DECLARATION OF YOLANDA ANDERSEN

I, Yolanda Andersen, declare as follows:

1. I am the Director of Member Services at the Sierra Club. I have had this position for more than 22 years.
2. In that role, I manage all aspects of the Sierra Club's customer service functions related to members, including maintaining an accurate list of members and managing the organization's member databases.
3. The Sierra Club is a non-profit membership organization incorporated under the laws of the State of California.
4. The Sierra Club's mission is to explore, enjoy and protect the wild places of the Earth; to practice and promote the responsible use of the Earth's resources and ecosystems; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives.
5. The Sierra Club's Natural Gas Reform campaign is focused on reducing the amount and impacts of natural gas extraction, including preventing the export of unconventional natural gas without a full analysis of the environmental and public interest effects of such export.

6. When an individual becomes a member of the Sierra Club, his or her current residential address is recorded in our membership database. The database entry reflecting the member's residential address is verified or updated as needed.
7. The Sierra Club currently has 583,913 members in the United States, and 2,755 members in Louisiana. These members have a strong interest in protecting human health and the environment from the effects of natural gas extraction and export.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed in San Francisco, California on January 30, 2013.

Yolanda Andersen

Yolanda Andersen

Statement of
Christopher Smith
Deputy Assistant Secretary for Oil and Natural Gas
Office of Fossil Energy
U.S. Department of Energy

Before the

Committee on Energy and Natural Resources
United States Senate

The Department of Energy's Role in Liquefied Natural Gas Export Applications

November 8, 2011

Thank you Chairman Bingaman, Ranking Member Murkowski, and members of the Committee; I appreciate the opportunity to be here today to discuss the Department of Energy's (DOE) program regulating the export of natural gas, including liquefied natural gas (LNG).

DOE's Statutory Authority

DOE's authority to regulate the export of natural gas arises under section 3 of the Natural Gas Act, 15 USC 717b, and section 301(b) of the DOE Organization Act, 42 USC 7151. That authority is vested in the Secretary of Energy and has been delegated to the Assistant Secretary for Fossil Energy.

Section 3(a) of the Natural Gas Act sets forth the standard for review of most LNG export applications:

> – [N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary of Energy] authorizing it to do so. The [Secretary] shall issue such order upon application, unless after opportunity for hearing, [he] finds that the proposed exportation or importation will not be consistent with the public interest. The [Secretary] may by [the Secretary's] order grant such application, in whole or part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate.

Section 3(a) thus creates a rebuttable presumption that a proposed export of natural gas is in the public interest, and requires DOE to grant an export application unless DOE finds that the record in the proceeding of the application overcomes that presumption. Section 3(a) also authorizes DOE to attach terms or conditions to the order that the Secretary finds are necessary or appropriate to protect the public interest.

In the Energy Policy Act of 1992 (EPAct 92), Congress introduced a new section 3(c) to the Natural Gas Act. Section 3(c) created a different standard of review for applications to export natural gas, including LNG, to those countries with which the United States has in effect a free trade agreement requiring the national treatment for trade in natural gas. Section 3(c) requires such applications to be deemed consistent with the public interest, and requires such applications to be granted without modification or delay.

There are currently 15 countries with which the United States has in place free trade agreements that require national treatment for trade in natural gas. These 15 countries include:

- Australia, Bahrain, Canada, Chile, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Peru, and Singapore.

There also are two countries—Israel and Costa Rica—that have free trade agreements with the United States that do not require national treatment for trade in natural gas. Additionally, there are three more countries—South Korea, Colombia, and Panama—that have negotiated free trade agreements with the United States. While these three free trade agreements have recently been ratified by the U.S. Senate, the agreements have not yet taken effect. However, as negotiated, the agreements require national treatment for trade in natural gas, which will have the effect of bringing applications to export LNG to those three countries under section 3(c) of the Natural Gas Act.

Because applications under section 3(c) must be granted without modification or delay and are deemed to be in the public interest, DOE does not conduct a public interest analysis of those applications and cannot condition them by the insertion of terms which otherwise might be considered necessary or appropriate.

For applications requesting authority to export LNG to countries that do not have free trade agreements requiring national treatment for trade in natural gas, DOE conducts a full public interest review. A wide range of criteria are considered as part of DOE's public interest review process, including:

- Domestic need for the natural gas proposed for export
- Adequacy of domestic natural gas supply
- U.S. energy security
- Impact on the U.S. economy (GDP), consumers, and industry
- Jobs creation
- U.S. balance of trade
- International considerations
- Environmental considerations
- Consistency with DOE's long-standing policy of promoting competition in the marketplace through free negotiation of trade arrangements
- Other issues raised by commenters and/or interveners deemed relevant to the proceeding

DOE's review of applications to export LNG to non-free trade agreement countries is conducted through a publicly transparent process. Upon receipt of an application, DOE issues a notice of the application in the *Federal Register*, posts the application and all subsequent pleadings and orders in the proceeding on its website, and invites interested persons to participate in the proceeding by intervening and/or filing comments or protests. Section 3(a) applicants are typically given an opportunity to respond to any such comments or protests and, after consideration of the evidence that has been introduced into the record, DOE issues an order either granting the application as requested, granting with additional terms or conditions, or denying the application.

Under the Natural Gas Act, DOE's orders are subject to a rehearing process that can be initiated by any party to a proceeding seeking to challenge DOE's determinations. Court review is available as well after the rehearing process is exhausted.

Recent Developments in LNG Exports

Over the last several years, domestic natural gas production has increased significantly, primarily due to the development of improved drilling technologies, including the ability to produce natural gas trapped in shale gas geologic formations. The most recent data and analysis prepared by the Energy Information Administration (EIA) within DOE shows an increasing volume of shale gas production. Specifically, EIA indicates that domestic gross gas production from shale increased to 3.4 trillion cubic feet (Tcf) in 2009, compared to 2.3 Tcf in 2008.[1] Further, in the Annual Energy Outlook 2011 (AEO 2011), EIA projected that, by 2015, annual dry shale gas production will increase to 7.2 Tcf and, by 2035, to 12.2 Tcf. Natural gas prices have declined and imports of LNG have significantly declined. Recently, the domestic price of natural gas at the Henry Hub for November 2011 delivery was $3.60 per million Btu.[2] International prices of LNG are significantly higher. Due in part to these changing market economics, DOE has begun to receive a growing number of applications to export domestically produced lower-48 natural gas to overseas markets in the form of LNG.

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[1] EIA, *Natural Gas Gross Withdrawals and Production, Release Date: October 29, 2011 http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm*

[2] The November 2011 contract price as of October 24, 2011, was $3.60 per million Btu.

Insofar as these applications have involved exports to free trade agreement countries, they are by statute, deemed consistent with the public interest and DOE is required to grant them without modification or delay. To the extent the applications involve non-free trade agreement countries, as I have indicated above, DOE conducts a thorough public interest analysis and attaches terms and conditions which are necessary or appropriate to protect the public interest.

Sabine Pass Liquefaction, LLC

DOE received the first application for long-term (greater than 2 years) authority to export LNG produced in the lower-48 States to non-free trade agreement countries on September 7, 2010, from Sabine Pass Liquefaction, LLC (Sabine Pass), a subsidiary of Cheniere Energy, Inc. This followed on DOE's earlier issuance of authority to Sabine Pass to export a like volume of natural gas to free trade agreement countries on September 7, 2010. A notice of the non-free trade agreement export application was published in the *Federal Register* and the public was provided 60 days to intervene and/or protest the application.

Sabine Pass' non-free trade agreement export application sought authority to export the equivalent of up to 2.2 billion cubic feet per day (Bcf/d) of natural gas, equivalent to about 3.3 percent of current domestic consumption. In its application, Sabine Pass pointed to several economic and public benefits likely to follow on a grant of the requested authorization, including:

– Creation of several thousand temporary and permanent jobs, both through direct and indirect job formation; and

- Improvement in U.S. balance of payments valued at approximately $6.7 billion from LNG exports and the impact of increased production of natural gas liquids.

Additionally, Sabine Pass addressed the question of the domestic need for the gas to be exported; the volume of domestic supplies; and the likely impact of the proposed exports on natural gas prices. To this end, it included with its application several economic and technical reports indicating that any increase in natural gas prices from the proposed exports would be relatively modest and not detrimental to domestic energy security.

Sabine Pass's application was opposed by the Industrial Energy Consumers of America and the American Public Gas Association. Those groups challenged Sabine Pass' claims of economic benefits and no detrimental impact on domestic energy security. However, neither opponent of the application introduced economic or technical studies to support their allegations.

DOE closely analyzed the evidence introduced by the applicant and by those opposing the application. Mindful of the statutory presumption favoring a grant of the application, the agency found that:

- The studies introduced by applicant indicated LNG exports will result in a modest projected increase in domestic market price for natural gas, which reflects the increasing marginal costs of domestic production; and

- The public record supported the conclusion that the requested authorization will yield tangible benefits to the public whereas the allegations of negative impacts submitted by interveners opposing the application were not substantiated on the record. In particular, the interveners failed to offer any rebuttal studies of natural gas supply, demand and/or price analysis to support their claim the application was not consistent with the public interest.

Following a review of the record in this proceeding, DOE concluded that the opponents of the application had not demonstrated that a grant of the requested authorization would be inconsistent with the public interest, and DOE granted the requested authorization subject to several terms and conditions.

Pending LNG Export Applications

As indicated above, applicants are increasingly seeking authorization from DOE to export domestic supplies of natural gas as LNG to higher priced overseas markets. The Natural Gas Act favors granting applications to export to non-free trade agreement countries unless it can be demonstrated that a proposed export is inconsistent with the public interest. In the case of exports of LNG to free trade agreement countries that require national treatment for trade in natural gas, DOE is without any authority to deny, condition, or otherwise limit such exports.

Mindful of the growing interest in exporting domestically produced LNG, DOE recognized in the Sabine Pass order that the cumulative impact of Sabine Pass and additional future LNG export authorizations could pose a threat to the public interest. DOE stated that it would monitor the cumulative impact and take such action as necessary in future orders.

DOE presently has before it four long-term applications to export lower-48 domestically produced LNG to countries with which the United States does not have a free trade agreement that requires national treatment for trade in natural gas. The volumes of LNG that could be authorized for export in these non-free trade agreement applications, including the 2.2 Bcf/d authorized for export in Sabine Pass, would total 6.6 Bcf/d, which represents 10 percent of total current domestic natural gas daily consumption in the United States. Consistent with the Natural Gas Act, DOE already has granted authorization from these five facilities to export this same volume to free trade agreement countries.

In order to address the potential cumulative impact of a grant of the pending applications, DOE has commissioned two studies: one by the EIA and the other by a private contractor. Taken together, these studies will address the impacts of additional natural gas exports on domestic energy consumption, production, and prices, as well as the cumulative impact on the U.S. economy, including the effect on gross domestic product, jobs creation, and balance of trade, among other factors. We anticipate that these studies will be completed in the first quarter of calendar year 2012. In this regard, we are mindful of the need for prompt action in each of the proceedings before us. However, we believe that a sound evidentiary record is essential in order to proceed to a decision and that the studies being undertaken are important elements of such a record.

Conclusion

I am happy to answer any questions that you may have.

Group	Name	Population	Status	Lead Office	Recovery Plan Name	Recovery Plan Stage
Birds	Brown pelican (Pelecanus	except U.S. Atlantic coast, FL,	Recovery	Ventura Fish And Wildlife Office		
Birds	Piping Plover (Charadrius	except Great Lakes watershed	Threatened	Office Of The Regional Director	Great Lakes & Northern Great	Final
Birds	Piping Plover (Charadrius	except Great Lakes watershed	Threatened	Office Of The Regional Director	Piping Plover Atlantic Coast	Final Revision 1
Birds	Sprague's pipit (Anthus		Candidate	North Dakota Ecological		
Fishes	Gulf sturgeon (Acipenser	Entire	Threatened	Panama City Ecological	Gulf Sturgeon	Final
Fishes	Pallid sturgeon (Scaphirhynchus	Entire	Endangered	Yellowstone River Coordinator	Pallid Sturgeon	Final
Mammals	West Indian Manatee	Entire	Endangered	North Florida Ecological	Florida Manatee Recovery Plan,	Final Revision 3
Mammals	West Indian Manatee	Entire	Endangered	North Florida Ecological	Recovery Plan Puerto Rican	Final
Mammals	Louisiana black bear (Ursus	Entire	Threatened	Louisiana Ecological Services	Louisiana Black Bear	Final
Reptiles	Hawksbill sea turtle	Entire	Endangered	North Florida Ecological	Recovery Plan for the Hawksbill	Final Revision 1
Reptiles	Hawksbill sea turtle	Entire	Endangered	North Florida Ecological	Recovery Plan for U.S. Pacific	Final Revision 1
Reptiles	Leatherback sea turtle	Entire	Endangered	North Florida Ecological	Recovery Plan for U.S. Pacific	Final Revision 1
Reptiles	Leatherback sea turtle	Entire	Endangered	North Florida Ecological	Recovery Plan for Leatherback	Final Revision 1
Reptiles	Kemp's ridley sea turtle	Entire	Endangered	Corpus Christi Ecological	Bi-National Recovery Plan for	Final Revision 2
Reptiles	Green sea turtle (Chelonia	except where endangered	Threatened	North Florida Ecological	Recovery Plan for U.S.	Final Revision 1
Reptiles	Green sea turtle (Chelonia	except where endangered	Threatened	North Florida Ecological	Recovery Plan for U.S. Pacific	Final Revision 1

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OFFICE OF
ECOSYSTEMS,
TRIBAL AND PUBLIC
AFFAIRS

October 29, 2012

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1A
Washington, DC 20426

Re: SCOPING COMMENTS – The Jordan Cove Energy Project LP and the Pacific Connector Gas Pipeline Notice of Intent to Prepare an Environmental Impact Statement. EPA Region 10 Project Number: 12-0042-FRC and 12-0049-AFS. *FERC Docket Nos. PF12-7-000 and PF12-17-000.*

Dear Secretary Bose:

The U.S. Environmental Protection Agency (EPA) would like to provide detailed scoping comments in response to the Federal Energy Regulatory Commission's (FERC's) August 13, 2012 Notice of Intent (NOI) to prepare an Environmental Impact Statement (EIS) for the Jordan Cove Energy Project and Pacific Connector Gas Pipeline. With these comments we are also responding to the September 21, 2012 NOI to prepare an EIS issued by the Forest Service and BLM for Right of Way grants and land use amendments related to the Pacific Connector Gas Pipeline. These comments were prepared in accordance with our authorities pursuant to the National Environmental Policy Act (NEPA), Section 309 of the Clean Air Act, the Clean Water Act, and our responsibilities as a Cooperating Agency. We appreciate the opportunity for early involvement at this step of the NEPA process.

The Clean Air Act Section 309 directs the EPA to review and comment in writing on the environmental impacts resulting from certain proposed actions of other federal agencies and the adequacy of the Draft EIS in meeting the procedural and public disclosure requirements in accordance with NEPA. Please see the EPA's review criteria for rating Draft EISs at the EPA web site: (http://www.epa.gov/compliance/nepa/comments/ratings.html). Our review authorities under Section 309 are independent of our responsibilities as a Cooperating Agency for this EIS.

The FERC's NOI describes Jordan Cove's proposal to construct and operate an LNG export terminal on the North Spit of Coos Bay. The terminal would have the capacity to produce approximately six million metric tons per annum of LNG (equivalent to 0.9 billion cubic feet per day [Bcf/d] of natural gas). Facilities would include:

- 7.3 mile long waterway in Coos Bay for about 80 LNG carriers per year;
- 0.3 mile long access channel and marine berth;
- A cryogenic transfer pipeline;
- Two 160,000 cubic meter LNG storage tanks;
- Four liquefaction trains (each with a capacity of 1.5 million metric tons per annum);
- Two feed gas and dehydration trains with a combined throughput of 1Bcf/d of natural gas; and
- A 350 megawatt South Dunes power plant.

The attendant Pacific Connector pipeline would be 36 inches in diameter and about 230 miles long, extending from interconnections with other interstate pipelines near Malin, Oregon to the Jordan Cove LNG terminal at Coos Bay. The pipeline would have a design capacity of 0.9 Bcf/d of natural gas. Related facilities include:

- Two meter stations at the interconnections with the existing Gas Transmission Northwest and Ruby pipelines near Malin, Oregon;
- A 23,000 horsepower compressor station adjacent to the GTN and Ruby meter stations;
- A meter station at the interconnection with the existing Williams Northwest Pipeline system near Myrtle Creek, Oregon; and
- A meter station at the Jordan Cove terminal.

The enclosed scoping comments were prepared based on our review of the NOIs referenced above and the draft Resource Reports 1 and 10. Our comments reflect a broad range of issues that we believe to be significant and warrant treatment in the EIS. Among these issues is the range of alternatives. We encourage the FERC to consider a broad range of reasonable alternatives in the EIS that are capable of meeting the project's purpose and need and we look forward to continued discussions on this matter. For example, we would be interested in discussing whether an intertie with the Williams pipeline could be considered as a reasonable alternative and examined in the EIS. We also recommend expanding the scope of analysis to capture the non-jurisdictional South Dunes power plant as well as indirect effects related to gas drilling and combustion.

As a Cooperating Agency, we look forward to continued communication with your office throughout the development of the EIS, and we are available to work with FERC to review and comment on preliminary sections of the document. If you have any questions regarding our scoping comments, please do not hesitate to contact me at (206) 553-1601 or by electronic mail at reichgott.christine@epa.gov, or you may contact Teresa Kubo of my staff in the Oregon Operations Office at (503) 326-2859 or by electronic mail at kubo.teresa@epa.gov. We look forward to our continued coordination and involvement in this project.

Sincerely,

Christine B. Reichgott

Christine B. Reichgott, Manager
Environmental Review and Sediment Management Unit

Enclosure

U.S. Environmental Protection Agency
Detailed Scoping Comments to Address the Federal Energy Regulatory Commission's Notice of Intent to Prepare an Environmental Impact Statement for the Jordan Cove Energy Project and Pacific Connector Gas Pipeline
FERC Docket Nos. PF12-7-000 and PF12-17-000

Purpose and Need
The EIS should include a clear and concise statement of the underlying purpose and need for the proposed project, consistent with the implementing regulations for NEPA (see 40 CFR 1502.13). In presenting the purpose and need for the project, the EIS should reflect not only the FERC's purpose, but also the broader public interest and need.

In supporting the statement of purpose and need, we recommend discussing the proposed project in the context of the larger energy market, including existing export capacity and export capacity under application to the Department of Energy, and clearly describe how the need for the proposed action has been determined.

Alternatives Analysis
NEPA requires evaluation of reasonable alternatives, including those that may not be within the jurisdiction of the lead agency[1]. A robust range of alternatives will include options for avoiding significant environmental impacts. The EIS should "rigorously explore and objectively evaluate all reasonable alternatives"[2] by developing a screening process. The screening process should rate each alternative against a set of pre-determined criteria. Each alternative should then be analyzed for its level of impact on a resource (e.g. no effect, negligible effect, minor effect, major effect, significant effect). Only the alternative that effectively meets or best meets all of the screening criteria should be recommended as the preferred alternative. The EIS should provide a clear discussion of the reasons for the elimination of alternatives which are not evaluated in detail.

We appreciate that Resource Report 10 for the Pacific Connector Pipeline Project (Section 10.4) evaluates system alternatives for the pipeline route. In the EIS we would like to see a more rigorous exploration of those alternatives. The basis for conclusions reached in Section 10.4.4 is not clear. Specifically, it is not clear how it was determined that an intertie with the Williams pipeline would result in prohibitive costs, associated rates, and environmental impacts. Because such a route would be significantly shorter than the currently proposed route, we recommend that the EIS give this route alternative additional consideration.

Non-Jurisdictional Facilities
In Section 1.9.2 of Resource Report 1, it is determined that as a non-jurisdictional facility, the South Dunes Power Plant does not need to be included in the DEIS. This assertion is based on the Report's interpretation of FERC's NEPA regulations at 18 CFR § 380.12(c)(2)(ii). Per those regulations, four factors are applied to determine the need for FERC to do an environmental review of project-related non-jurisdictional facilities. These factors include:

[1] 40 CFR 1502.14(c)
[2] 40 CFR 1502.14(a)

1. Whether or not the regulated activity comprises "merely a link" in a corridor type project (such as a transportation or utility transmission project);
2. Whether there are aspects of the non-jurisdictional facility in the immediate vicinity of the regulated activity which affect the location and configuration of the regulated activity;
3. The extent to which the entire project will be within the FERC's jurisdiction; and
4. The extent of cumulative federal control and responsibility.

Resource Report 1 considers each of these factors and finds that FERC environmental review is not warranted. We believe the Resource Report's interpretation of these criteria to be overly narrow. In particular, because the South Dunes Power Plant and the Jordan Cove Export Facility are interdependent and interconnected, we believe the power plant inherently affects the location of the export facility. Without the power supplied by the power plant, the export facility cannot be built; and without the export facility, there is no need for the power plant to be built.

In addition, CEQ NEPA regulations at 40 CFR 1508.25(a)(1) address connected actions, and clearly call for actions to be considered within the scope of an EIS if they "cannot or will not proceed unless other actions are taken previously or simultaneously" or " are interdependent parts of a larger action and depend on the larger action for their justification"[3]. It is clear from Resource Report 1 that the Power Plant is being constructed for the purpose of supporting the Project. The Power Plant is not being constructed for a purpose independent from the Project. On the contrary, it is being constructed specifically to support the power needs of the Project.

Section 40 C.F.R. 1508.25(a)(3) states that two actions should be evaluated in a single EIS when they are "similar actions, which when viewed with other reasonably foreseeable or proposed agency actions have similarities that provide a basis for evaluating their environmental consequences together, such as common timing and geography." The Power Plant will be built in a timeframe that will coincide with the Project's power needs. The Power Plant is specifically sited in proximity to the Project so that it can operate in conjunction with the Project. Because the South Dunes Power Plan and the Jordan Cove Export Facility are interdependent and interconnected, the locations of the two were selected to enhance the effectiveness of their co-operation. Therefore, we recommend that the FERC include the South Dunes Power Plant within the scope of the EIS.

Environmental Consequences
According to 40 CFR Part 1502.1, an Environmental Impact Statement, "...shall provide full and fair discussion of significant environmental impacts and shall inform decision makers and the public of the reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the environment." In order to facilitate a full and fair discussion on significant environmental issues, we encourage the FERC to establish thresholds of significance for each resource of concern, and to analyze environmental consequences in a clear, repeatable manner. For each action, a series of questions should be considered: 1) What is the action? 2) What is the intensity or extent of impacts? 3) Based on identified thresholds, is that significant? If an impact of the action is significant, then the EIS must contain appropriate mitigation measures.

[3] 40 CFR 1508.25(a)(1)(ii) and (iii)

Water Quality

In order to adequately address water quality issues, the EPA recommends the EIS identify water bodies likely to be impacted by the project, the nature of the potential impacts, and the specific discharges and pollutants likely to impact those waters (addressing both Section 402 and 404 discharges and potential impairments to water quality standards). We also recommend the EIS disclose information regarding relevant Total Maximum Daily Load allocations, the water bodies to which they apply, water quality standards and pollutants of concern.

Clean Water Act Section 303(d) listed waters should not be further degraded. If additional pollutant loading is predicted to occur to a 303(d) listed stream as a result of a project, the EIS should include measures to control existing sources of pollution to offset pollutant additions.

Consider implementing watershed or aquatic habitat restoration activities to compensate for past impacts to water resources, particularly in watersheds with 303(d) listed waters where development may have contributed to impairments through past channelization, riverine or floodplain encroachments, sediment delivery during construction, and other activities that may have affected channel stability, water quality, aquatic habitat, and designated waterbody uses. Provisions for antidegradation of water quality apply to water bodies where water quality standards are presently being met. We recommend the EIS describe how antidegradation provisions would be met.

Hydrostatic Test Water

Hydrostatic testing of pipelines and tanks will be required to verify their integrity. We recommend that the EIS identify the water sources and withdrawal rates that would be required for hydrostatic testing. We recommend that the EIS identify and describe the location of these water sources (surface areas, depth, volumes, withdrawal rates, and project requirements). For each water source, we recommend that the EIS discuss the presence of any anadromous and/or resident fish species, including a discussion of any direct and cumulative impacts to fisheries resources. In addition, we recommend that the locations of discharge to land and/or surface waters, and discharge methods be specified in the EIS. Emphasis should be placed on minimizing interbasin transfers of water to the maximum extent practicable in order to minimize the risk of mobilizing invasive species. We recommend that the EIS describe the mitigation measures and control devices that would be implemented to minimize environmental impacts.

Source Water Protection

Public drinking water supplies and/or their source areas often exist in many watersheds. Source water areas may exist within watersheds where the pipeline and associated facilities would be located. Source waters are streams, rivers, lakes, springs, and aquifers used as supply for drinking water. Source water areas are delineated and mapped by the states for each federally-regulated public water system. The 1996 amendments to the Safe Drinking Water Act require federal agencies to protect sources of drinking water for communities. As a result, state agencies have been delegated responsibility to conduct source water assessments and provide a database of information about the watersheds and aquifers that supply public water systems.

Since construction, operation, and maintenance of a buried natural gas pipeline may impact sources of drinking water, the EPA recommends that the FERC work with the Oregon Department of Environmental Quality to identify source water protection areas. Typical databases contain information about the watersheds and aquifer recharge areas, the most sensitive zones within those areas, and the numbers and types of potential contaminant sources for each system. We recommend that the EIS identify source water protection areas within the project area, activities (e.g., trenching and excavation, water withdrawal, etc.) that could potentially affect source water areas, potential contaminants that may result from the proposed project and mitigation measures that would be taken to protect the source water protection areas.

Wetlands and Aquatic Habitats

In the EIS, we recommend describing aquatic habitats in the affected environment (e.g., habitat type, plant and animal species, functional values, and integrity) and the environmental consequences of the proposed alternatives on these resources. Impacts to aquatic resources should be evaluated in terms of the areal (acreage) or linear extent to be impacted and by the functions they perform.

The proposed activities will require a Clean Water Act Section 404 permit from the Army Corps of Engineers. For wetlands and other special aquatic sites, the Section 404(b) (1) guidelines establish a presumption that upland alternatives are available for non-water dependent activities. The 404(b)(1) guidelines require that impacts to aquatic resources be (1) avoided, (2) minimized, and (3) mitigated, in that sequence. We recommend the EIS discuss in detail how planning efforts (and alternative selection) conform with Section 404(b)(1) guidelines sequencing and criteria. In other words, we request the FERC show that impacts to wetlands and other special aquatic sites have been avoided to the maximum extent practicable. The EPA also recommends the EIS discuss alternatives that would avoid wetlands and aquatic resource impacts from fill placement, water impoundment, construction, and other activities before proceeding to minimization/ mitigation measures.

The EPA recommends the EIS describe all waters of the U.S. that could be affected by the project alternatives, and include maps that clearly identify all waters within the project area. We also request the document include data on acreages and channel lengths, habitat types, values, and functions of these waters. As discussed above, projects affecting waters of the U.S. may need to comply with CWA Section 404 requirements. If project alternatives involve discharge of dredged or fill material into waters of the U.S., the EIS should include information regarding alternatives to avoid the discharges or how potential impacts caused by the discharges would be minimized and mitigated. This mitigation discussion would include the following elements:

- acreage and habitat type of waters of the U.S. that would be created or restored;
- water sources to maintain the mitigation area;
- re-vegetation plans, including the numbers and age of each species to be planted, as well as special techniques that may be necessary for planting;
- maintenance and monitoring plans, including performance standards to determine mitigation success;
- size and location of mitigation zones;
- mitigation banking and/or in lieu fees where appropriate;
- parties that would be ultimately responsible for the plan's success; and
- contingency plans that would be enacted if the original plan fails.

Where possible, mitigation should be implemented in advance of the impacts to avoid habitat losses due to the lag time between the occurrence of the impact and successful mitigation.

Water Body Crossing

As noted in Section 1.6.4 of Resource Report 1, the PCGP Project would affect 383 waterbodies. We appreciate the effort that the FERC and the proponent have made in the past to establish appropriate water body crossing procedures. We encourage the FERC to build upon these efforts through the use of risk screening tools that have been developed since the FEIS for the Jordan Cove LNG Export Facility was finalized. Specifically, we encourage the use of 1) a Project Screening Risk Matrix to evaluate the potential risks posed by the project to species or habitat, and to prioritize reviews; 2) a Project Information Checklist to evaluate whether all the necessary information is available to facilitate critical and thorough project evaluation; and 3) the River Restoration Assessment Tool, which can promote consistent and comprehensive project planning and review. These tools are available at www.restorationreview.com.

Maintenance Dredging

Resource Report 1 (Section 1.1.2.2) states that maintenance dredging requirements have been revised based on new modeling. The new estimate is that approximately 37,700 cubic yards would need to be dredged for maintenance at year 1. At year 10 that volume would be expected to decrease to 34,600 cubic yards. This is a substantial reduction from estimates of maintenance dredging included in the FEIS for the Jordan Cove Import Facility. We continue to request the inclusion of an analysis supporting the assertion that the capacity of the EPA's Ocean Disposal Site F would be unaffected by the addition of maintenance dredging material over the next 20 years in the EIS. In order for the EPA to concur with the issuance of a Section 103 permit, this will need to be clearly demonstrated.

In addition, we encourage the development of a Maintenance Dredging Plan in consultation with the U.S. Army Corps of Engineers and the EPA. That plan, including disposal, should be consistent with the site management and monitoring plan and reviewed and approved as part of the Section 103 permit process.

Air Quality

The EPA recommends the EIS provide a detailed discussion of ambient air conditions (baseline or existing conditions), National Ambient Air Quality Standards, criteria pollutant nonattainment areas, and potential air quality impacts of the proposed project (including cumulative and indirect impacts). Such an evaluation is necessary to assure compliance with State and Federal air quality regulations, and to disclose the potential impacts from temporary or cumulative degradation of air quality. The EPA recommends the EIS describe and estimate air emissions from potential construction, operation, and maintenance activities, including emissions associated with LNG carriers at berth. The analysis should also include assumptions used regarding the types of fuel burned and/or the ability for carriers to utilize dockside power (i.e. cold ironing). Emissions at berth are of particular relevance because the deep draft LNG carriers would be required to remain docked between high tides. We also recommend proposing mitigation measures in the EIS to address identified emissions impacts.

Fugitive Dust Emissions

Fugitive dust may contain small airborne particles that have the potential to adversely affect human health and the environment. The EPA defines fugitive dust as "particulate matter that is generated or emitted from open air operations (emissions that do not pass through a stack or a vent)". The most common forms of particulate matter (PM) are known as PM_{10} and $PM_{2.5}$ (particulate matter size less than 10 and 2.5 microns, respectively).

Sources of fugitive dust from this project may include unpaved gravel roads and facility pads, and clearing and construction sites. Effects of fugitive dust to the natural environment may include visibility reduction and haze, surface water impacts, impacts to wetlands, and reduction in plant growth. Fugitive dust may pose a human health risk due to chronic exposure in areas with vulnerable populations, such as infants and the elderly. The EPA recommends the EIS evaluate the magnitude and significance of fugitive dust emissions resulting from this project and potential impacts on human health.

We also recommend that a Dust Control Plan be developed and included as an appendix to the EIS. This plan should include provisions for monitoring fugitive dust during construction and operations, and implementing measures to reduce fugitive dust emissions, such as wetting the source material, installing barriers to prevent dust from leaving the source area, and halting operations during high wind events. We recommend that the EIS identify mitigation measures to avoid and minimize potential adverse impacts to the natural and human environment.

Biological Resources, Habitat and Wildlife

The EPA recommends the EIS identify all petitioned and listed threatened and endangered species under the Endangered Species Act, as well as critical habitat that might occur within the project area. We also recommend the EIS identify and quantify which species or critical habitat might be directly, indirectly, or cumulatively affected by each alternative and mitigate impacts to those species. The EPA recommends that the FERC continue to work with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service. The EPA also recommends that the FERC continue to coordinate with the Oregon Department of Fish and Wildlife to ensure that State sensitive species are adequately addressed within the analysis and that current and consistent surveying, monitoring, and reporting protocols are applied in protection and mitigation efforts.

The EPA recommends the EIS also identify species listed under the Marine Mammal Protection Act. Marine barge/vessel traffic may result in potential conflicts with threatened and/or endangered marine mammals and their migration patterns and routes. We also recommend that the EIS describe the barge/vessel traffic schedule, patterns and marine transportation routes, as well as the migration period, patterns, and routes of potentially affected marine mammals. The direct, indirect and cumulative impacts from barge/vessel traffic on marine mammals, threatened and endangered species, critical habitats, and subsistence resources should be analyzed in the EIS.

Land Use Impacts

Land use impacts would include, but not be limited to, disturbance of existing land uses within construction work areas during construction and creation of permanent right-of-ways for construction, operations, and maintenance of the pipeline and above ground facilities. The EPA recommends the EIS document all land cover and uses within the project corridor, impacts by the project to the land cover and uses, and mitigation measures that would be implemented to reduce the impacts.

The primary impact of construction on forests and other open land use types would be the removal of trees, shrubs, and other vegetation. Although these can be regenerated or replanted, their re-establishment can take up to 20 years or more, making the construction impacts to these resources long term and in some cases permanent. The impact on forest land use, for example, in the permanent right-of-way areas would be a permanent change to open land. We recommend the EIS describe the impacts to forest and open land use types, indicate if the impacts would be permanent or temporary, and state measures that would be taken to compensate landowners for loss of their resources because of the project.

If the project would cross sensitive areas then the EIS should specify the areas, indicate impacts to the areas, and document any easement conditions for use of the areas, including mitigation measures.

Invasive Species
The establishment of invasive nuisance species has become an issue of environmental and economic significance. The EPA recommends consideration of impacts associated with invasive nuisance species consistent with *E.O. 13112 Invasive Species*. In particular, construction activities associated with buried pipelines which disturb the ground may expose areas and could facilitate propagation of invasive species. Mitigation, monitoring and control measures should be identified and implemented to manage establishment of invasive species throughout the entire pipeline corridor right-of-way. We recommend that the EIS include a project design feature that calls for the development of an invasive species management plan to monitor and control noxious weeds, and to utilize native plants for restoration of disturbed areas after construction.

If pesticides and herbicides will be applied during construction, operation, and maintenance of the project, we recommend that the EIS address any potential toxic hazards related to the application of the chemicals, and describe what actions will be taken to assure that impacts by toxic substances released to the environment will be minimized.

Ballast water from barges/vessels is a major source of introducing non-native species into the marine ecosystems where they would not otherwise be present. Non-native species can adversely impact the economy, the environment, or cause harm to human health. Impacts may include reduction of biodiversity of species inhabiting coastal waters from competition between non-native and native species for food and resources. We recommend that the EIS discuss potential impacts from non-native invasive species associated with ballast water and identify mitigation measures to minimize adverse impacts to the marine environment and human health.

Hazardous Materials/Hazardous Waste/Solid Waste
The EPA recommends EIS address potential direct, indirect, and cumulative impacts of hazardous waste from construction and operation of the proposed project. The document should identify projected hazardous waste types and volumes, and expected storage, disposal, and management plans. It should identify any hazardous materials sites within the project's study area and evaluate whether those sites would impact the project in any way.

Seismic and Other Risks
Construction and operation of the proposed facility and pipeline may cause or be affected by increased seismicity (earthquake activity) in tectonically active zones. We recommend that the EIS identify potentially active and inactive fault zones where the proposed pipeline may cross. This analysis should discuss the potential for seismic risk and how this risk will be evaluated, monitored, and managed. A map depicting these geologic faults should be included in the EIS. The construction of the proposed project must use appropriate seismic design and construction standards and practices. Ground movement on these faults can cause a pipeline to rupture, resulting in discharge of gas and subsequent explosion. Particular attention should be paid to areas where the pipeline may cross areas with high population

densities. Mitigation measures should be identified in the EIS to minimize effects on the pipeline due to seismic activities.

Blasting Activities

During project construction, blasting may be required in certain areas along the pipeline route corridor and adjacent facilities, resulting in increased noise and related effects to local residents, and disruption and displacement of bird and wildlife species. We recommend that the EIS discuss where blasting in the project area would be required, blasting methods that would be used, and how blasting effects would be controlled and mitigated. Noise levels in the project area should be quantified and the effects of blasting to the public and to wildlife should also be evaluated in the EIS. We recommend that a Blasting Management Plan be developed and the environmental impacts evaluated in the EIS.

National Historic Preservation Act

Consultation for tribal cultural resources is required under Section 106 of the National Historic Preservation Act (NHPA). Historic properties under the NHPA are properties that are included in the National Register of Historic Places or that meet the criteria for the National Register. Section 106 of the NHPA requires a federal agency, upon determining that activities under its control could affect historic properties, consult with the appropriate State Historic Preservation Officer /Tribal Historic Preservation Officer. Under NEPA, any impacts to tribal, cultural, or other treaty resources must be discussed and mitigated. Section 106 of the NHPA requires that federal agencies consider the effects of their actions on cultural resources, following regulation in 36 CFR 800.

Environmental Justice and Impacted Communities

In compliance with NEPA and with Executive Order (EO) 12898 on Environmental Justice, actions should be taken to conduct adequate public outreach and participation that ensures the public and Native American tribes understand the possible impacts to their communities and trust resources.

EO 12898 requires each Federal agency to identify and address disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations, low-income populations, and Native American tribes.[4] The EPA also considers children, the disabled, the elderly, and those of limited English proficiency to be potential Environmental Justice communities due to their unique vulnerabilities.

According to the Council on Environmental Quality, when determining whether environmental effects are disproportionately high and adverse, agencies should consider the following factors: [5]

- Whether environmental effects are or may be having an adverse impact on minority populations, low-income populations, or Indian tribes that appreciably exceeds or is likely to appreciably exceed those on the general population or other appropriate comparison group
- Whether the disproportionate impacts occur or would occur in a minority population, low-income population, or Indian tribe affected by cumulative or multiple adverse exposures from environmental hazards

[4] EO 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-income Populations. February 11, 1994.

[5] http://ceq.hss.doe.gov/nepa/regs/ej/justice.pdf

Socioeconomic Impacts

Council on Environmental Quality Regulations at 40 CFR 1500-1508 state that the "human environment" is to be "interpreted comprehensively" to include "the natural and physical environment and the relationship of people with that environment" (40 CFR 1508.14). Consistent with this direction, agencies need to assess not only "direct" effects, but also "aesthetic, historic, cultural, economic, social, or health" effects, "whether direct, indirect, or cumulative" (40 CFR 1508.8).

Social impact assessment variables point to measurable change in human population, communities, and social relationships resulting from a development project or policy change. We suggest that the EIS analyze the following social variables:

- Population Characteristics
- Community and Institutional Structures
- Political and Social Resources
- Individual and Family Changes
- Community Resources

Impacts to these social variables should be considered for each stage of the project (development, construction, operation, decommissioning). With regard to the construction and operation phase of the project, we recommend the analysis give consideration to how marine traffic might change, and how this may affect commercial or recreational use on the bay and travel over the bar.

Greenhouse Gas (GHG) Emissions

On February 18, 2010, the CEQ issued draft guidance to Federal Agencies on analyzing the effects of Greenhouse Gas (GHG) emissions and climate change when describing the environmental effects of a proposed agency action in accordance with NEPA[6].

CEQ's draft guidance defines GHG emissions in accordance with Section 19(i) of *E.O. 13514 Federal Leadership in Environment, Energy, and Economic Performance (October 5, 2009)* to include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorcarbon (HFCs), perfluorcarbon (PFCs), and sulfurhexafluoride (SF_6). Because CO_2 is the reference gas for climate change based on their potential to absorb heat in the atmosphere, measures of non-CO_2 GHGs should be reflected as CO_2-equivalent (CO_2-e) values.

The EPA supports evaluation and disclosure of GHG emissions and climate change effects resulting from the proposed project during all project phases, including (1) pre-construction (e.g., transportation, mobilization, and staging), (2) construction, (3) operation, (4) maintenance, and (5) decommissioning. We recommend that the GHG emission accounting/inventory include each proposed stationary source (e.g., power plant, liquefaction facility, compressor and metering stations, etc.) and mobile emission source (e.g., heavy equipment, supply barges, rail transports, etc.). We also recommend that the EIS establish reasonable spatial and temporal boundaries for this analysis, and that the EIS quantify and disclose the expected annual direct and indirect GHG emissions for the proposed action. In the analysis of direct effects, we recommend that the EIS quantify cumulative emissions over the life of the project, discuss measures to reduce GHG emissions, including consideration of reasonable alternatives

[6]See http://ceq.hss.doe.gov/current_developments/new_ceq_nepa_guidance.html

We recommend that the EIS consider mitigation measures and reasonable alternatives to reduce action-related GHG emissions, and include a discussion of cumulative effects of GHG emissions related to the proposed action. We recommend that this discussion focus on an assessment of annual and cumulative emissions of the proposed action and the difference in emissions associated with the alternatives.

In addition, greenhouse gas emission sources in the petroleum and natural gas industry are required to report GHG emissions under 40CFR Part 98 (subpart W), the Greenhouse Gas Reporting Program. Consistent with draft CEQ guidance[5], we recommend that this information be included in the EIS for consideration by decision makers and the public. Please see http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

Climate Change
Scientific evidence supports the concern that continued increases in greenhouse gas emissions resulting from human activities will contribute to climate change. Global warming is caused by emissions of carbon dioxide and other heat-trapping gases. On December 7, 2009, the EPA determined that emissions of GHGs contribute to air pollution that "endangers public health and welfare" within the meaning of the Clean Air Act. Higher temperatures and increased winter rainfall will be accompanied by a reduction in snow pack, earlier snowmelts, and increased runoff. Some of the impacts, such as reduced groundwater discharge, and more frequent and severe drought conditions, may impact the proposed projects. The EPA recommends the EIS consider how climate change could potentially influence the proposed project, specifically within sensitive areas, and assess how the projected impacts could be exacerbated by climate change.

Coordination with Tribal Governments
Executive Order 13175, Consultation and Coordination with Indian Tribal Governments (November 6, 2000), was issued in order to establish regular and meaningful consultation and collaboration with tribal officials in the development of federal policies that have tribal implications, and to strengthen the United States government-to-government relationships with Indian tribes. The EIS should describe the process and outcome of government-to-government consultation between the FERC and tribal governments within the project area, issues that were raised, and how those issues were addressed in the selection of the proposed alternative.

Indirect Impacts
Per CEQ regulations at CFR 1508.8(b), the indirect effects analysis "may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems." The 2012 report from the Energy Information Administration[7] states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report goes on to say that about three-quarters of that increase production would be from shale resources. We believe it is appropriate to consider available information about the extent to which drilling activity might be stimulated by the construction of an LNG export facility on the west coast, and any potential environmental effects associated with that drilling expansion.

[7] Energy Information Administration, Effects of Increased Natural Gas Exports on Domestic Energy Markets, 6 (January 2012) available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf

Cumulative Impacts

The cumulative impacts analysis should identify how resources, ecosystems, and communities in the vicinity of the project have already been, or will be affected by past, present, or future activities in the project area. These resources should be characterized in terms of their response to change and capacity to withstand stresses. Trends data should be used to establish a baseline for the affected resources, to evaluate the significance of historical degradation, and to predict the environmental effects of the project components.

For the cumulative impacts assessment, we recommend focusing on resources of concern or resources that are "at risk" and /or are significantly impacted by the proposed project, before mitigation. For this project, the FERC should conduct a thorough assessment of the cumulative impacts to aquatic and biological resources (including plover habitat), air quality, and commercial and recreational use of the bay. We believe the EIS should consider the Oregon Gateway Marine Terminal Complex as described by the Port of Coos Bay (http://www.portofcoosbay.com/orgate.htm) as reasonably foreseeable for the purposes of cumulative effects analysis. We recognize that uncertainty about future development of the North Spit remains, but we believe the stated aspirations of the Port and the Oregon Department of State Lands' 2011 issuance of a removal-fill permit for the development of an access channel and multi-purpose vessel slip provide sufficient reason for including the marine terminal complex in the effects analysis.

The EPA also recommends the EIS delineate appropriate geographic boundaries, including natural ecological boundaries, whenever possible, and should evaluate the time period of the project's effects. For instance, for a discussion of cumulative wetland impacts, a natural geographic boundary such as a watershed or sub-watershed could be identified. The time period, or temporal boundary, could be defined as from 1972 (when the Clean Water Act established section 404) to the present.

Please refer to CEQ's "Considering Cumulative Effects Under the National Environmental Policy Act"[8] and the EPA's "Consideration of Cumulative Impacts in EPA Review of NEPA Documents"[9] for assistance with identifying appropriate boundaries and identifying appropriate past, present, and reasonably foreseeable future projects to include in the analysis.

Mitigation and Monitoring

On February 18, 2010, CEQ issued draft guidance on the Appropriate Use of Mitigation and Monitoring. This guidance seeks to enable agencies to create successful mitigation planning and implementation procedures with robust public involvement and monitoring programs[10].

We recommend that the EIS include a discussion and analysis of proposed mitigation measures and compensatory mitigation under CWA §404. The EIS should identify the type of activities which would require mitigation measures either during construction, operation, and maintenance phases of this project. To the extent possible, mitigation goals and measureable performance standards should be identified in the EIS to reduce impacts to a particular level or adopted to achieve an environmentally preferable outcome.

[8] http://ceq.hss.doe.gov/nepa/ccenepa/ccenepa.htm
[9] http://www.epa.gov/compliance/resources/policies/nepa/cumulative.pdf
[10] http://ceq.hss.doe.gov/current_developments/docs/Mitigation_and_Monitoring_Guidance_14Jan2011.pdf

Mitigation measures could include best management practices and options for avoiding and minimizing impacts to important aquatic habitats and to compensate for the unavoidable impacts. Compensatory mitigation options could include mitigation banks, in-lieu fee, preservation, applicant proposed mitigation, etc. and should be consistent with the *Compensatory Mitigation for Losses of Aquatic Resources; Final Rule* (33 CFR Parts 325 and 332 and 40 CFR Part 230). A mitigation plan should be developed in compliance with 40 CFR Part 230 Subpart J 230.94, and included in the EIS.

An environmental monitoring program should be designed to assess both impacts from the project and that mitigation measures being implemented are effective. We recommend the EIS identify clear monitoring goals and objectives, such as what parameters are to be monitored, where and when monitoring will take place, who will be responsible, how the information will be evaluated, what actions (contingencies, triggers, adaptive management, corrective actions, etc.) will be taken based on the information. Furthermore, we recommend the EIS discuss public participation, and how the public can get information on mitigation effectiveness and monitoring results.

ORIGINAL

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

November 15, 2012

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

RE: EPA Region 3 Scoping Comments in Response to FERC's Notice of Intent to Prepare an Environmental Assessment (EA) for the Planned Cove Point Liquefaction Project; FERC Docket No. PF12-16-000

Dear Secretary Bose:

The U.S. Environmental Protection Agency (EPA), Region III Office, has conducted a review of the above Notice in conjunction with our responsibilities under the National Environmental Policy Act (NEPA), the Clean Water Act (CWA) and Section 309 of the Clean Air Act. As part of the FERC pre-filing process of soliciting public and agency comments for development of the EA, EPA offers the following scoping comments.

The NOI describes Dominion's proposal to add an LNG export terminal to its existing LNG import terminal on the Chesapeake Bay in Lusby, Maryland. The new terminal would have capacity to process and export up to 750 million standard cubic feet of natural gas per day (0.75 billion cubic feet/day). Facilities would include:

- Natural gas fired turbines to drive the main refrigerant compressors;
- One or two LNG drive trains and new processing facilities;
- 29,000 to 34,000 additional horsepower compression at its existing Loudon County, VA
- Compressor Station and/or its existing Pleasant Valley (Fairfax County, VA) Compressor Station;
- Additional on-site power generation
- Minor modifications to the existing off-shore pier;
- Use of nearby properties and possible relocation of administrative functions

The Project would not include new LNG storage tanks or an increase in the size and/or frequency of LNG marine traffic currently authorized for the Cove Point LNG Terminal. The NEPA document should include a clear and robust justification of the underlying purpose and need for the proposed project. In order for the project to move forward, FERC would need to issue a certificate of "public convenience and necessity". We recommend discussing the proposal in the context of the broader energy market, including existing and proposed LNG export capacity, describing the factors involved in determining public convenience and necessity for this facility.

EPA recommends assessing the cumulative environmental effects resulting from implementation of the proposed project, when combined with other past, present and reasonably foreseeable future actions, regardless of whether these actions are energy related or not, or whether or not FERC has jurisdiction over them. We recommend focusing on resources or communities of concern, or resources "at risk" which could be cumulatively impacted by all of the above actions. Please refer to the Council on Environmental Quality (CEQ) guidance on "Considering Cumulative Effects Under the National Environmental Policy Act", and EPA's "Consideration of Cumulative Impacts in EPA Review of NEPA Documents" for further assistance in identifying appropriate spatial and temporal boundaries for this analysis.

We also recommend expanding the scope of analysis to include indirect effects related to gas drilling and combustion. A 2012 report (http://www.eia.gov/analysis/requests/fe/) from the Energy Information Administration (EIA) states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report also indicated that about three-quarters of that increase production would be from shale resources and that domestic natural gas prices could rise by more than 50% if permitted to be exported. We believe it is appropriate to consider the extent to which implementation of the proposed project, combined with implementation of other similar facilities nationally, could increase the demand for domestic natural gas extraction and increase domestic natural gas prices. As part of this assessment, please discuss the extent to which implementation of the proposed project would create a demand for construction of new gas pipelines or expansion of existing pipelines, in order to accommodate the increased volumes of gas supplied to the Cove Point and other facilities.

In the air impact analysis for the Cove Point Project, we recommend considering the direct, temporary emissions from construction of all facilities, as well as permanent air emission impacts from facility operations, including all compressor stations and any vessel traffic related to LNG exports. Additionally, indirect and reasonably foreseeable cumulative impacts from past, present and future actions, when added to the incremental impacts of the Project proposed should be evaluated. These other actions should include FERC jurisdictional facilities and energy generating and transporting-related facilities, as well as actions or facilities which might have air emissions which could impact the same air receptors as the Project, including downstream combustion.

Please note whether construction or operation of the Project would involve any discharges to Waters of the United States, and whether it would affect the Chesapeake Bay Total Maximum Daily Load (TMDL) or any related Watershed Implementation Plans (WIPs).

As part of any environmental documentation, please include evaluation of the Project's direct and indirect impacts on the nearby Chesapeake Bay fisheries and fishermen (both recreational and commercial). Will any additional dredging of waterways be required to accommodate the vessels exporting LNG? What biosecurity controls and protocols will be instituted to prevent introduction of invasive species due to ballast water releases? Please include a discussion of how the Project will comply with the Magnuson-Stevens Fishery Conservation and Management Act, as amended by the Sustainable Fisheries Act of 1966 (PL 04-267)(Essential Fish Habitat).

Please express the volume of natural gas proposed to be exported in terms that the average reader can more easily understand. For example, in addition to indicating that the Project would be capable of processing an average of 750 million standard cubic feet of natural gas per day, also express that figure as an equivalent number of average homes this amount of gas could heat, or how many tankers, and of what size, this amount of gas would fill. Also, please calculate how many production wells, on average, would need to be drilled in order to produce this amount of gas.

The NOI states that the Project would not increase the size and/or frequency of LNG marine traffic currently authorized for the Cove Point LNG Terminal. Please discuss in the NEPA document whether this would be accomplished by reducing the volume of LNG imports to match the volume of proposed exports, or by employing some other approach.

Please indicate the number, location, size and capacity of the network of bidirectional pipelines from which the proposed Project would or could receive natural gas, and also indicate whether any of those pipelines would need to be expanded or modified in order to provide the volumes of gas anticipated.

Please indicate whether any aspect of the Project would trigger any requirements for hazardous waste management under the Resource Conservation and Recovery Act (RCRA) or other Federal statutes involving management of such waste.

The proposed Dominion Cove Point facility represents one of sixteen (16) applications currently pending before the U.S. Department of Energy (DOE) for approval to export LNG to countries which do not have Free Trade Agreements (FTA) with the United States. At this time, it appears that only one facility has been initially granted full approval (Sabine Pass in Cameron Parish, Louisiana). Although we are aware of the DOE national study in progress on the cumulative *economic* impacts of allowing natural gas exports, EPA believes that the Cove Point NEPA process represents an opportunity for FERC and DOE to jointly and thoroughly consider the indirect and cumulative *environmental* impacts of exporting LNG from Cove Point. The environmental study of the Cove Point Project should be a comprehensive and robust evaluation of potential impacts, which may require a higher level analysis particularly in consideration of the potential for significant cumulative impacts and the level of community interest.

Thank you for the opportunity to comment on this Notice. EPA welcomes the opportunity to discuss these topics by phone or in-person, at your convenience. If you have any questions concerning these comments, please contact Mr. Thomas Slenkamp of this Office at (215) 814-2750.

Sincerely,

Jeffrey D. Lapp, Associate Director
Office of Environmental Programs

Document Content(s)

Independent Statistics & Analysis
U.S. Energy Information Administration

Effect of Increased Natural Gas Exports on Domestic Energy Markets

as requested by the Office of Fossil Energy

January 2012

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

Contacts

The Office of Energy Analysis prepared this report under the guidance of John Conti, Assistant Administrator for Energy Analysis. General questions concerning the report can be directed to Michael Schaal (michael.schaal@eia.gov, 202/586-5590), Director, Office of Petroleum, Natural Gas and Biofuels Analysis; and Angelina LaRose, Team Lead, Natural Gas Markets Team (angelina.larose@eia.gov, 202/586-6135).

Technical information concerning the content of the report may be obtained from Joe Benneche (joseph.benneche@eia.gov, 202/586-6132).

Preface

The U.S. Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The views in this report, therefore, should not be construed as representing those of the Department of Energy or other Federal agencies.

The projections in this report are not statements of what *will* happen but of what *might* happen, given the assumptions and methodologies used. The Reference case in this report is a business-as-usual trend estimate, reflecting known technology and technological and demographic trends, and current laws and regulations. Thus, it provides a policy-neutral starting point that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes.

Contents

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Introduction

This report responds to an August 2011 request from the Department of Energy's Office of Fossil Energy (DOE/FE) for an analysis of "the impact of increased domestic natural gas demand, as exports." Appendix A provides a copy of the DOE/FE request letter. Specifically, DOE/FE asked the U.S. Energy Information Administration (EIA) to assess how specified scenarios of increased natural gas exports could affect domestic energy markets, focusing on consumption, production, and prices.

DOE/FE provided four scenarios of export-related increases in natural gas demand (Figure 1) to be considered:

- 6 billion cubic feet per day (Bcf/d), phased in at a rate of 1 Bcf/d per year (low/slow scenario),
- 6 Bcf/d phased in at a rate of 3 Bcf/d per year (low/rapid scenario),
- 12 Bcf/d phased in at a rate of 1 Bcf/d per year (high/slow scenario), and
- 12 Bcf/d phased in at a rate of 3 Bcf/d per year (high/rapid scenario).

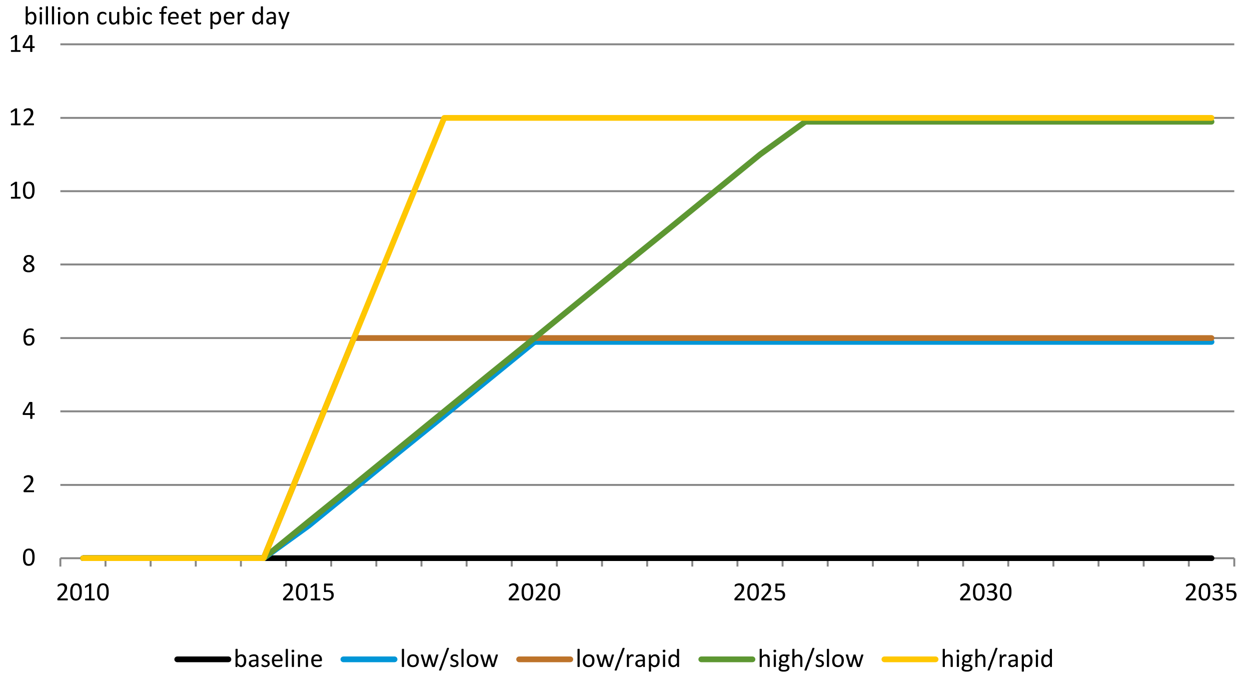
Total marketed natural gas production in 2011 was about 66 Bcf/d. The two ultimate levels of increased natural gas demand due to additional exports in the DOE/FE scenarios represent roughly 9 percent or 18 percent of current production.

DOE/FE requested that EIA consider the four scenarios of increased natural gas exports in the context of four cases from the EIA's *2011 Annual Energy Outlook* (*AEO2011*) that reflect varying perspectives on the domestic natural gas supply situation and the growth rate of the U.S. economy. These are:

- the *AEO2011* Reference case,
- the High Shale Estimated Ultimate Recovery (EUR) case (reflecting more optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent higher than in the Reference case),
- the Low Shale EUR case (reflecting less optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent lower than in the Reference case), and
- the High Economic Growth case (assuming the U.S. gross domestic product will grow at an average annual rate of 3.2 percent from 2009 to 2035, compared to 2.7 percent in the Reference case, which increases domestic energy demand).

DOE/FE requested this study as one input to their assessment of the potential impact of current and possible future applications to export domestically produced natural gas. Under Section 3 of the Natural Gas Act (NGA) (15 U.S.C. § 717b), DOE must evaluate applications to import and export natural gas and liquefied natural gas (LNG) to or from the United States. The NGA requires DOE to grant a permit unless it finds that such action is not consistent with the public interest. As a practical matter, the need for DOE to make a public interest judgment applies only to trade involving countries that have not entered into a free trade agreement (FTA) with the United States requiring the national treatment for trade in natural gas and LNG. The NGA provides that applications involving imports from or exports to an FTA country are deemed to be in the public interest and shall be granted without modification or delay. Key countries with FTAs include Canada and Mexico, which engage in significant natural gas trade with the United States via pipeline. A FTA with South Korea, currently the world's second largest importer of LNG, which does not currently receive domestically produced natural gas from the United States, has been ratified by both the U.S. and South Korean legislatures, but had not yet entered into force as of the writing of this report.

Figure 1. Four scenarios of increased natural gas exports specified in the analysis request



Source: U.S. Energy Information Administration based on DOE Office of Fossil Energy request letter

Analysis approach

EIA used the *AEO2011* Reference case issued in April 2011 as the starting point for its analysis and made several changes to the model to accommodate increased exports. EIA exogenously specified additional natural gas exports from the United States in the National Energy Modeling System (NEMS), as the current version of NEMS does not generate an endogenous projection of LNG exports. EIA assigned these additional exports to the West South Central Census Division.[1] Any additional natural gas consumed during the liquefaction process is counted within the total additional export volumes specified in the DOE/FE scenarios. Therefore the net volumes of LNG produced for export are roughly 10 percent below the gross volumes considered in each export scenario.

Other changes in modeled flows of gas into and out of the lower-48 United States were necessary to analyze the increased export scenarios. U.S. natural gas exports to Canada and U.S. natural gas imports from Mexico are exogenously specified in all of the *AEO2011* cases. U.S. imports of natural gas from

[1] This effectively assumes that incremental LNG exports would be shipped out of the Gulf Coast States of Texas or Louisiana.

Canada are endogenously set in the model and continue to be so for this study. However, U.S. natural gas exports to Mexico and U.S. LNG imports that are normally determined endogenously within the model were set to the levels projected in the associated *AEO2011* cases for this study. Additionally, EIA assumed that an Alaska pipeline, which would transport Alaskan produced natural gas into the lower-48 United States, would not be built during the forecast period in any of the cases in order to isolate the lower-48 United States supply response. Due to this restriction, both the *AEO2011* High Economic Growth and Low Shale EUR cases were rerun, as those cases had the Alaska pipeline entering service during the projection period in the published *AEO2011*.

Caveats regarding interpretation of the analysis results

EIA recognizes that projections of energy markets over a 25-year period are highly uncertain and subject to many events that cannot be foreseen, such as supply disruptions, policy changes, and technological breakthroughs. This is particularly true in projecting the effects of exporting significant natural gas volumes from the United States due to the following factors:

- NEMS is not a world energy model and does not address the interaction between the potential for additional U.S. natural gas exports and developments in world natural gas markets.
- Global natural gas markets are not integrated and their nature could change substantially in response to significant changes in natural gas trading patterns. Future opportunities to profitably export natural gas from the United States depend on the future of global natural gas markets, the inclusion of relevant terms in specific contracts to export natural gas, as well as on the assumptions in the various cases analyzed.
- Macroeconomic results have not been included in the analysis because the links between the energy and macroeconomic modules in NEMS do not include energy exports.
- NEMS domestic focus makes it unable to account for all interactions between energy prices and supply/demand in energy-intensive industries that are globally competitive. Most of the domestic industrial activity impacts in NEMS are due to changes in the composition of final demands rather than changes in energy prices. Given its domestic focus, NEMS does not account for the impact of energy price changes on the global utilization pattern for existing capacity or the siting of new capacity inside or outside of the United States in energy-intensive industries.

Representation of natural gas markets

Unlike the oil market, current natural gas markets are not integrated globally. In today's markets, natural gas prices span a range from $0.75 per million British thermal units (MMBtu) in Saudi Arabia to $4 per MMBtu in the United States and $16 per MMBtu in Asian markets that rely on LNG imports. Prices in European markets, which reflect a mix of spot prices and contract prices with some indexation to oil, fall between U.S and Asian prices. Spot market prices at the U.K. National Balancing Point averaged $9.21 per MMBtu during November 2011.

Liquefaction projects typically take four or more years to permit and build and are planned to run for at least 20 years. As a result, expectations of future competitive conditions over the lifetime of a project play a critical role in investment decisions. The current large disparity in natural gas prices across major world regions, a major driver of U.S. producers' interest in possible liquefaction projects to increase natural gas exports, is likely to narrow as natural gas markets become more globally integrated. Key questions remain regarding how quickly convergence might occur and to what extent it will involve all or only some global regions. In particular, it is unclear how far converged prices may reflect purely "gas on gas" competition, a continuing relationship between natural gas and oil prices as in Asia (and to a lesser extent in Europe), or some intermediate outcome. As an example of the dynamic quality of global gas markets, recent regulatory changes combined with abundant supplies and muted demands appear to have put pressure on Europe's oil-linked contract gas prices.

U.S. market conditions are also quite variable, as monthly average Henry Hub spot prices have ranged from over $12 to under $3 per MMBtu over the past five years. Furthermore, while projected Henry Hub prices in the *AEO2011* Reference case reach $7.07 per MMBtu in 2035, in the High and Low Shale EUR cases prices in 2035 range from $5.35 per MMBtu to $9.26 per MMBtu.[2] For purposes of this study, the scenarios of additional exports posited by DOE/FE in their request do not vary across the different baseline cases that are considered. In reality, given available prices in export markets, lower or higher U.S. natural gas prices would tend to make any given volume of additional exports more or less likely.

The prospects for U.S. LNG exports depend greatly on the cost-competitiveness of liquefaction projects in the United States relative to those at other locations. The investment to add liquefaction capacity to an existing regasification terminal in the United States is significant, typically several times the original cost of a regasification-only terminal. However, the ability to make use of existing infrastructure, including natural gas processing plants, pipelines, and storage and loading facilities means that U.S. regasification terminals can reduce costs relative to those that would be incurred by a "greenfield" LNG facility. Many of the currently proposed LNG supply projects elsewhere in the world are integrated standalone projects that would produce, liquefy, and export stranded natural gas. These projects would require much more new infrastructure, entailing not only the construction of the liquefaction plant from the ground up, but also storage, loading, and production facilities, as well pipelines and natural gas processing facilities.

While the additional infrastructure for integrated standalone projects adds considerably to their cost, such projects can be sited at locations where they can make use of inexpensive or stranded natural gas resources that would have minimal value independent of the project. Also, while these projects may require processing facilities to remove impurities and liquids from the gas, the value of the separated liquids can improve the overall project economics. On the other hand, liquefaction projects proposed for the lower-48 United States plan to use pipeline gas drawn from the largest and most liquid natural gas market in the world. Natural gas in the U.S. pipeline system has a much greater inherent value than stranded natural gas, and most of the valuable natural gas liquids have already been removed.

Future exports of U.S. LNG depend on other factors as well. Potential buyers may place additional value on the greater diversity of supply that North American liquefaction projects provide. Also, the degree of regulatory and other risks are much lower for projects proposed in countries like the United States,

[2] All prices in this report are in 2009 dollars unless otherwise noted. For the Low Shale EUR case used in this study the Henry Hub price in 2035 is $9.75 per MMBtu, slightly higher than in the AEO2011 case with the Alaska pipeline projected to be built towards the end of the projection period.

Canada, and Australia than for those proposed in countries like Iran, Venezuela, and Nigeria. However, due to relatively high shipping costs, LNG from the United States may have an added cost disadvantage in competing against countries closer to key markets, such as in Asia. Finally, LNG projects in the United States would frequently compete not just against other LNG projects, but against other natural gas supply projects aimed at similar markets, such as pipeline projects from traditional natural gas sources or projects to develop shale gas in Asia or Europe.

Macroeconomic considerations related to energy exports and global competition in energy-intensive industries

Macroeconomic results have not been included in the analysis because energy exports are not explicitly represented in the NEMS macroeconomic module. [3] The macroeconomic module takes energy prices, energy production, and energy consumption as inputs (or assumptions) from NEMS energy modules. The macroeconomic module then calculates economic drivers that are passed back as inputs to the NEMS energy modules. Each energy module in NEMS uses different economic inputs; however these economic concepts are encompassed by U.S. gross domestic product (GDP), a summary measure describing the value of goods and services produced in the economy.[4]

The net exports component of GDP in the macroeconomic module, however, does not specifically account for energy exports. As a result, increases in energy exports generated in the NEMS energy modules are not reflected as increases in net exports of goods and services in the macroeconomic module. This results in an underestimation of GDP, all else equal. The components of GDP are calculated based on this underestimated amount as well, and do not reflect the increases in energy exports. This is particularly important in the industrial sector, where the value of its output will not reflect the increased energy exports either.

The value of output in the domestic industrial sector in NEMS depends in general on both domestic and global demand for its products, and on the price of inputs. Differences in these factors between countries will also influence where available production capacity is utilized and where new production capacity is built in globally competitive industries. For energy-intensive industries, the price of energy is particularly important to utilization decisions for existing plants and siting decisions for new ones. Given its domestic focus, however, NEMS does not account for the impact of energy price changes on global utilization pattern of existing capacity or the siting of new capacity inside or outside of the United States in energy-intensive industries. Capturing these linkages requires an international model of the particular industry in question, paired with a global macroeconomic model.

[3] In the macroeconomic model, energy exports are used in two places: estimating exports of industrial supplies and materials and estimating energy's impact on the overall production of the economy. To assess their impact on overall production, energy exports are included in the residual between energy supply (domestic production plus imports) and energy demand. This residual also includes changes in inventory.

[4] GDP is defined as the sum of consumption, investment, government expenditure and net exports (equal to exports minus imports).

Summary of Results

Increased natural gas exports lead to higher domestic natural gas prices, increased domestic natural gas production, reduced domestic natural gas consumption, and increased natural gas imports from Canada via pipeline.

Impacts overview

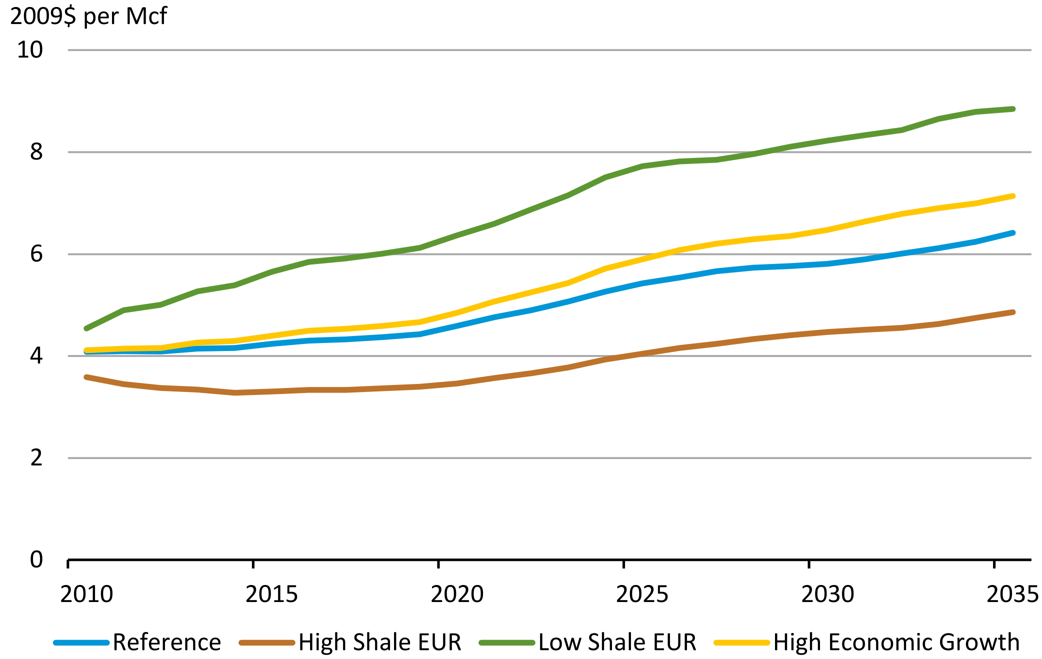
- **Increased natural gas exports lead to increased natural gas prices.** Larger export levels lead to larger domestic price increases, while rapid increases in export levels lead to large initial price increases that moderate somewhat in a few years. Slower increases in export levels lead to more gradual price increases but eventually produce higher average prices during the decade between 2025 and 2035.
- **Natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production.** Increased natural gas production satisfies about 60 to 70 percent of the increase in natural gas exports, with a minor additional contribution from increased imports from Canada. Across most cases, about three-quarters of this increased production is from shale sources.
- **The remaining portion is supplied by natural gas that would have been consumed domestically if not for the higher prices.** The electric power sector accounts for the majority of the decrease in delivered natural gas. Due to higher prices, the electric power sector primarily shifts to coal-fired generation, and secondarily to renewable sources, though there is some decrease in total generation due to the higher price of natural gas. There is also a small reduction in natural gas use in all sectors from efficiency improvements and conservation.
- **Even while consuming less, on average, consumers will see an increase in their natural gas and electricity expenditures.** On average, from 2015 to 2035, natural gas bills paid by end-use consumers in the residential, commercial, and industrial sectors combined increase 3 to 9 percent over a comparable baseline case with no exports, depending on the export scenario and case, while increases in electricity bills paid by end-use customers range from 1 to 3 percent. In the rapid growth cases, the increase is notably greater in the early years relative to the later years. The slower export growth cases tend to show natural gas bills increasing more towards the end of the projection period.

Natural gas prices

Wellhead natural gas prices in the baseline cases (no additional exports)
EIA projects that U.S. natural gas prices are projected to rise over the long run, even before considering the possibility of additional exports (Figure 2). The projected price increase varies considerably, depending on the assumptions one makes about future gas supplies and economic growth. Under the Reference case, domestic wellhead prices rise by about 57 percent between 2010 and 2035. But different assumptions produce different results. Under the more optimistic resource assumptions of the High Shale EUR case, prices actually fall at first and rise by only 36 percent by 2035. In contrast, under the more pessimistic resource assumptions of the Low Shale EUR case, prices nearly double by 2035.

While natural gas prices rise across all four baseline cases (no additional exports) considered in this report, it should be noted that natural gas prices in all of the cases are far lower than the price of crude oil when considered on an energy-equivalent basis. Projected natural gas prices in 2020 range from $3.46 to $6.37 per thousand cubic feet (Mcf) across the four baseline cases, which roughly corresponds to an oil price range of $20 to $36 per barrel in energy-equivalent terms. In 2030, projected baseline natural gas prices range from $4.47 to $8.23 per Mcf in the four baseline cases, which roughly corresponds to an oil price range of $25 to $47 per barrel in energy-equivalent terms.

Figure 2. Natural gas wellhead prices in the baseline cases (no additional exports)



Source: U.S. Energy Information Administration, National Energy Modeling System

Export scenarios—relationship between wellhead and delivered natural gas prices

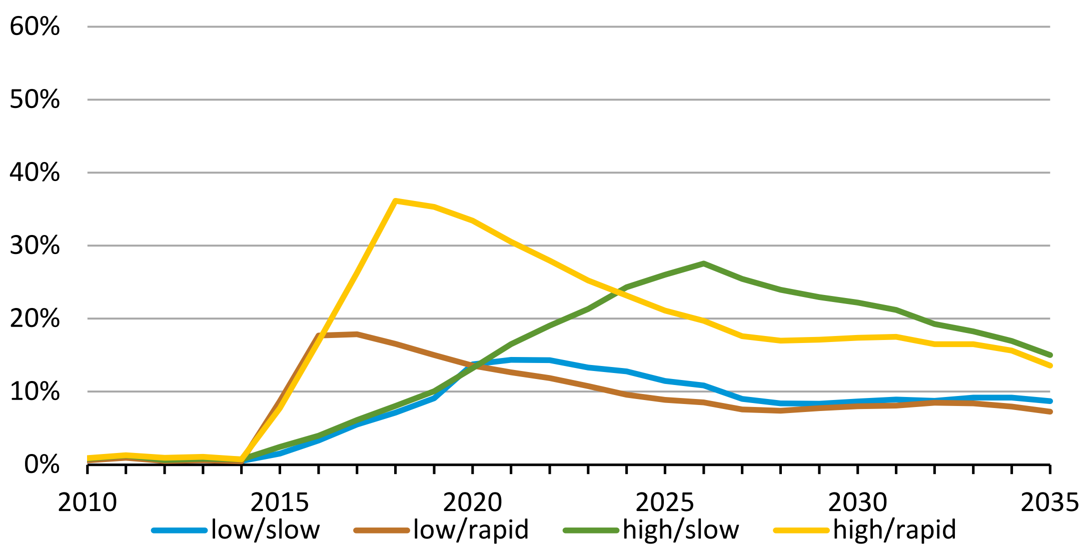
Increases in natural gas prices at the wellhead translate to similar absolute increases in delivered prices to customers under all export scenarios and baseline cases. However, delivered prices include transportation charges (for most customers) and distribution charges (especially for residential and commercial customers). These charges change to much less of a degree than the wellhead price does under different export scenarios. As a result, the percentage change in prices that industrial and electric customers pay tends to be somewhat lower than the change in the wellhead price. The percentage change in prices that residential and commercial customers pay is significantly lower. Summary statistics on delivered prices are provided in Appendix B. More detailed results on delivered prices and other report results can be found in the standard NEMS output tables that are posted online.

Export scenarios – wellhead price changes under the Reference case.

Increased exports of natural gas lead to increased wellhead prices in all cases and scenarios. The basic pattern is evident in considering how prices would change under the Reference case (Figure 3):

- The pattern of price increases reflects both the ultimate level of exports and the rate at which increased exports are phased in. In the low/slow scenario (which phases in 6 Bcf/d of exports over six years), wellhead price impacts peak at about 14% ($0.70/Mcf) in 2022. However, the wellhead price differential falls below 10 percent by about 2026.
- In contrast, rapid increases in export levels lead to large initial price increases that would moderate somewhat in a few years. In the high/rapid scenario (which phases in 12 Bcf/d of exports over four years), wellhead prices are about 36 percent higher ($1.58/Mcf) in 2018 than in the no-additional-exports scenario. But the differential falls below 20 percent by about 2026. The sharp projected price increases during the phase-in period reflect what would be needed to balance the market through changes in production, consumption, and import levels in a compressed timeframe.
- Slower increases in export levels lead to more gradual price increases but eventually produce higher average prices, especially during the decade between 2025 and 2035. The differential between wellhead prices in the high/slow scenario and the no-additional-exports scenario peaks in 2026 at about 28 percent ($1.53/Mcf), and prices remain higher than in the high/rapid scenario. The lower prices in the early years of the scenarios with slow export growth leads to more domestic investment in additional natural gas burning equipment, which increases demand somewhat in later years, relative to rapid export growth scenarios.

Figure 3. Natural gas wellhead price difference from *AEO2011* Reference case with different additional export levels imposed

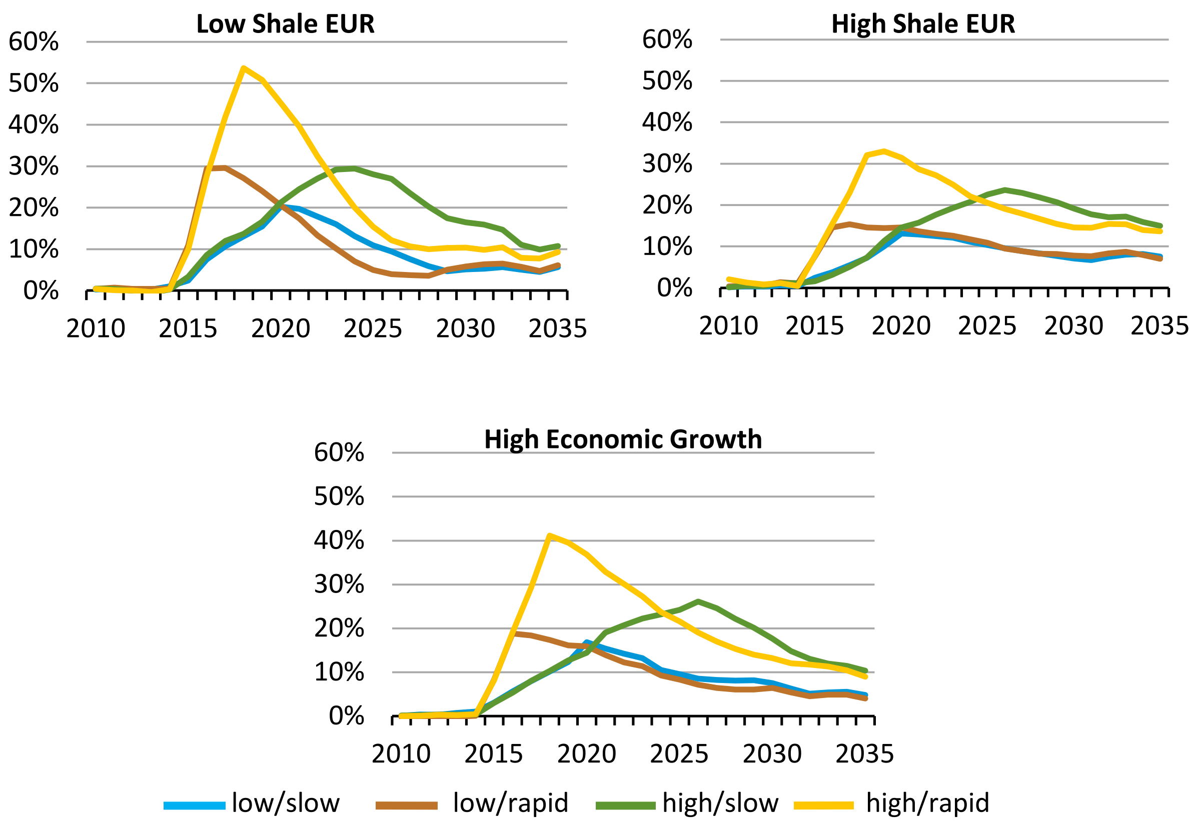


Source: U.S. Energy Information Administration, National Energy Modeling System

Export scenarios—wellhead price changes under alternative baseline cases

The effect of increasing exports on natural gas prices varies somewhat under alternative baseline case assumptions about resource availability and economic growth. However, the basic patterns remain the same: higher export levels would lead to higher prices, rapid increases in exports would lead to sharp price increases, and slower export increases would lead to slower but more lasting price increases. But the relative size of the price increases changes with changing assumptions (Figure 4).

Figure 4. Natural gas wellhead price difference from indicated baseline case (no additional exports) with different additional export levels imposed



Source: U.S. Energy Information Administration, National Energy Modeling System

In particular, with more pessimistic assumptions about the Nation's natural gas resource base (the Low Shale EUR case), wellhead prices in all export scenarios initially increase more in percentage terms over the baseline case (no additional exports) than occurs under Reference case conditions. For example, in the Low Shale EUR case the rapid introduction of 12 Bcf/d of exports results in a 54 percent ($3.23/Mcf) increase in the wellhead price in 2018; whereas under Reference case conditions with the same export scenario the price increases in 2018 by only 36 percent ($1.58/Mcf).[5] But the percentage price increase falls in later years under the Low Shale EUR case, even below the price response under Reference case conditions. Under Low Shale EUR conditions, the addition of exports ultimately results in wellhead prices exceeding the $9 per Mcf threshold, with this occurring as early as 2018 in the high/rapid scenario.

[5] The percentage rise in prices for the low EUR case also represents a larger absolute price increase because it is calculated on the higher baseline price under the same pessimistic resource assumptions.

More robust economic growth shows a similar pattern – higher initial percentage price increases and lower percentage increases in later years. On the other hand, with more optimistic resource assumptions (the High Shale EUR case), the percentage price rise would be slightly smaller than under Reference case conditions, and result in wellhead prices never exceeding the $6 per Mcf threshold.

Natural gas supply and consumption

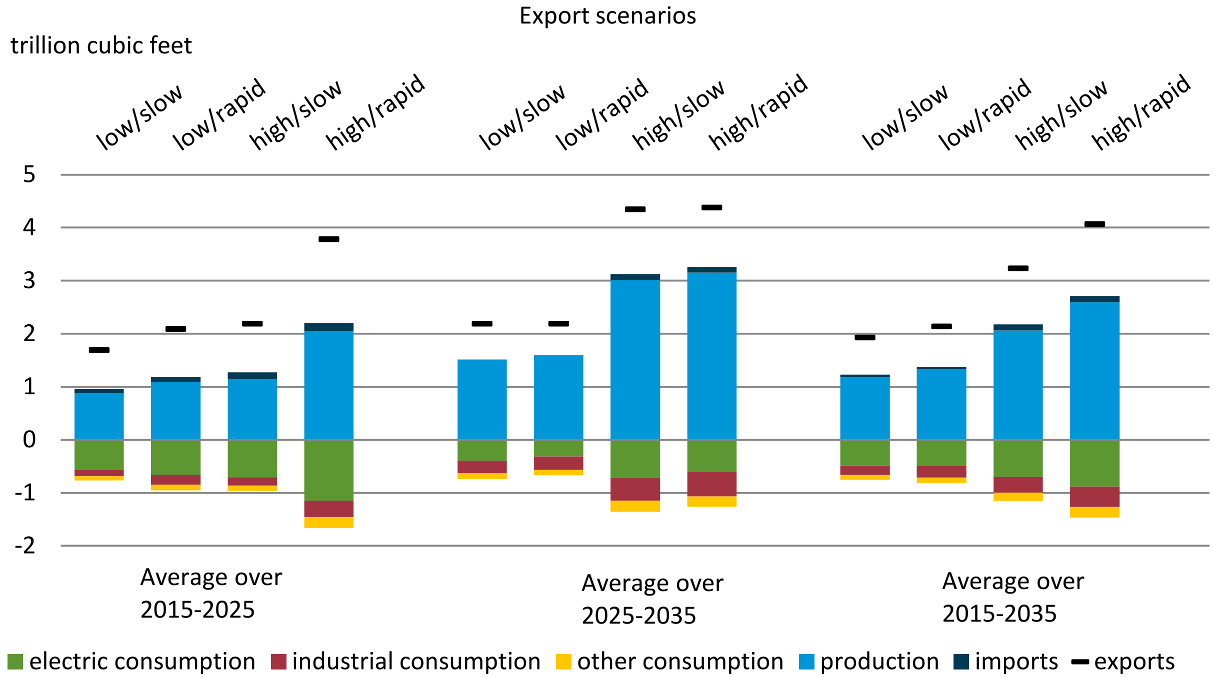
In the AEO2011 Reference case, total domestic natural gas production grows from 22.4 trillion cubic feet (Tcf) in 2015 to 26.3 Tcf in 2035, averaging 24.2 Tcf for the 2015-2035 period. U.S. net imports of natural gas decline from 11 percent of total supply in 2015 to 1 percent in 2035, with lower net imports from Canada and higher net exports to Mexico. The industrial sector consumes an average of 8.1 Tcf of natural gas (34.2% of delivered volumes) between 2015 and 2035, with 7.1 Tcf, 4.8 Tcf, and 3.6 Tcf consumed in the electric power, residential, and commercial sectors respectively.

Under the scenarios specified for this analysis, increased natural gas exports lead to higher domestic natural gas prices, which lead to reduced domestic consumption, and increased domestic production and pipeline imports from Canada (Figure 5). Lower domestic consumption dampens the degree to which supplies must increase to satisfy the additional natural gas exports. Accordingly, in order to accommodate the increased exports in each of the four export scenarios, the mix of production, consumption, and imports changes relative to the associated baseline case. In all of the export scenarios across all four baseline cases, a majority of the additional natural gas needed for export is provided by increased domestic production, with a minor contribution from increased pipeline imports from Canada. The remaining portion of the increased export volumes is offset by decreases in consumption resulting from the higher prices associated with the increased exports.

The absolute value of the sum of changes in consumption (delivered volumes), production, and imports (represented by the total bar in Figure 5) approximately[6] equals the average change in exports. Under Reference case conditions, about 63 percent, on average, of the increase in exports in each of the four scenarios is accounted for by increased production, with most of the remainder from decreased consumption from 2015 to 2035. The percentage of exports accounted for by increased production is slightly lower in the earlier years and slightly higher in the later years. While this same basic relationship between added exports and increased production is similar under the other cases, the percentage of added exports accounted for by increased production is somewhat less under a Low Shale EUR environment and more under a High Economic Growth environment.

[6] The figure displays the changes in delivered volumes of natural gas to residential, commercial, industrial, vehicle transportation, and electric generation customers. There are also some minor differences in natural gas used for lease, plant, and pipeline fuel use which are not included.

Figure 5. Average change in annual natural gas delivered, produced, and imported from *AEO2011* Reference case with different additional export levels imposed



Source: U.S. Energy Information Administration, National Energy Modeling System

One seeming anomaly that can be seen in Figure 5 is in the 2025 to 2035 timeframe: the decrease in consumption is somewhat lower in the rapid export penetration relative to the slow export penetration scenarios. This is largely attributed to slightly lower prices in the later years of the rapid export penetration scenarios relative to the slow penetration scenarios.

Supply

Increases in natural gas production that contribute to additional natural gas exports from the relative baseline scenario come predominately from shale sources. On average, across all cases and export scenarios, the shares of the increase in total domestic production coming from shale gas, tight gas, coalbed, and other sources are 72 percent, 13 percent, 8 percent, and 7 percent, respectively. Most of the export scenarios are also accompanied by a slight increase in pipeline imports from Canada. Under the Low Shale EUR case (which just applies to domestic shale), imports from Canada contribute to a greater degree than in other cases.

Consumption by sector

In general, greater export levels lead to higher domestic prices and larger decreases in consumption, although the price and consumption differences across the scenarios narrow in the later part of the projection period.

Electric power generation

In the AEO2011 Reference case, electric power generation averages 4,692 billion kilowatthours (bkWh) over the 2015-2035 period. Natural gas generation averages 23 percent of total power generation, increasing from 1,000 bkWh in 2015 to 1,288 bkWh in 2035. Coal, nuclear, and renewables provide an average of 43 percent, 19 percent, and 14 percent of generation, respectively, with a minimal contribution from liquids.

In scenarios with increased natural gas exports, most of the decrease in natural gas consumption occurs in the electric power sector (Figure 5). Most of the tradeoff in electric generators' natural gas use is between natural gas and coal, especially in the early years (Figure 6), when there is excess coal-fired capacity to allow for additional generation. Over the projection period, excess coal capacity progressively declines, along with the degree by which coal-fired generation can be increased in response to higher natural gas prices.[7] Increased coal-fired generation accounts for about 65 percent of the decrease in natural gas-fired generation under Reference case conditions.

The increased use of coal for power generation results in an average increase in coal production from 2015 to 2035 over Reference case levels of between 2 and 4 percent across export scenarios. Accordingly, coal prices also increase slightly which, along with higher gas prices, drive up electricity prices. The resulting increase in electricity prices reduces total electricity demand, also offsetting some of the drop in natural gas-fired generation. The decline in total electricity demand tends to be less in the earlier years.

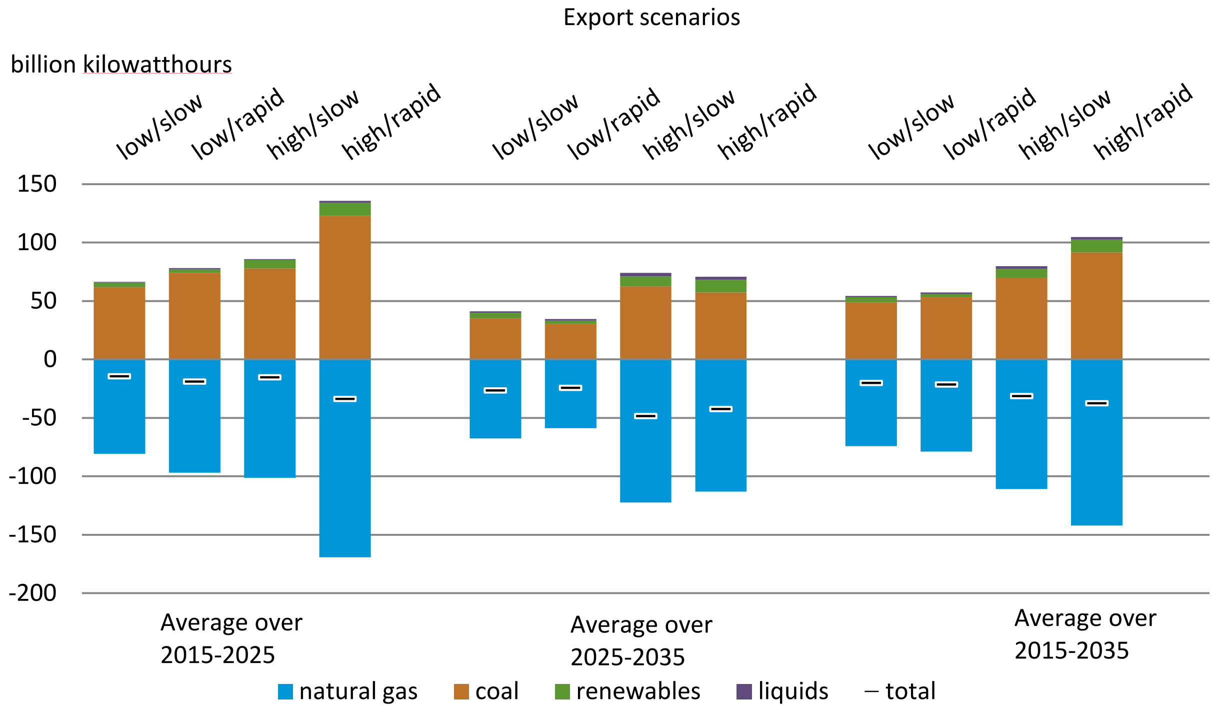
In addition, small increases in renewable generation contribute to reduced natural gas-fired generation. Relatively speaking, the role of renewables is greater in a higher-gas-price environment (i.e., the Low Shale EUR case), when they can more successfully compete with coal, and in a higher-generation environment (i.e., the High Economic Growth case), particularly in the later years.

Industrial sector

Reductions in industrial natural gas consumption in scenarios with increased natural gas exports tend to grow over time. In general, higher gas prices earlier in the projection period in these scenarios provide some disincentive for natural gas-fired equipment purchases (such as natural gas-fired combined heat and power (CHP) capacity) by industrial consumers, which has a lasting impact on their projected use of natural gas.

[7] The degree to which coal might be used in lieu of natural gas depends on what regulations are in-place that might restrict coal use. These scenarios reflect current laws and regulations in place at the time the *AEO2011* was produced.

Figure 6. Average change in annual electric generation from *AEO2011* Reference case with different additional export levels imposed



Source: U.S. Energy Information Administration, National Energy Modeling System

Note: Nucleargeneration levels do not change in the Reference case scenarios.

As noted in the discussion of caveats in the first section of this report, the NEMS model does not explicitly address the linkage between energy prices and the supply/demand of industrial commodities in global industries. To the extent that the location of production is very sensitive to changes in natural gas prices, industrial natural gas demand would be more responsive than shown in this analysis.

Other sectors

Natural gas consumption in the other sectors (residential, commercial, and compressed natural gas vehicles) also decreases in response to the higher gas prices associated with increased exports, although less significantly than in the electric and industrial sectors. Even so, under Reference case conditions residential and commercial consumption decreases from 1 to 2 percent and from 2 to 3 percent, respectively, across the export scenarios, on average from 2015 to 2035. Their use of electricity also declines marginally in response to higher electricity prices. In response to higher natural gas and electricity prices, residential and commercial customers directly cut back their energy usage and/or purchase more efficient equipment.

Exports to Canada and Mexico

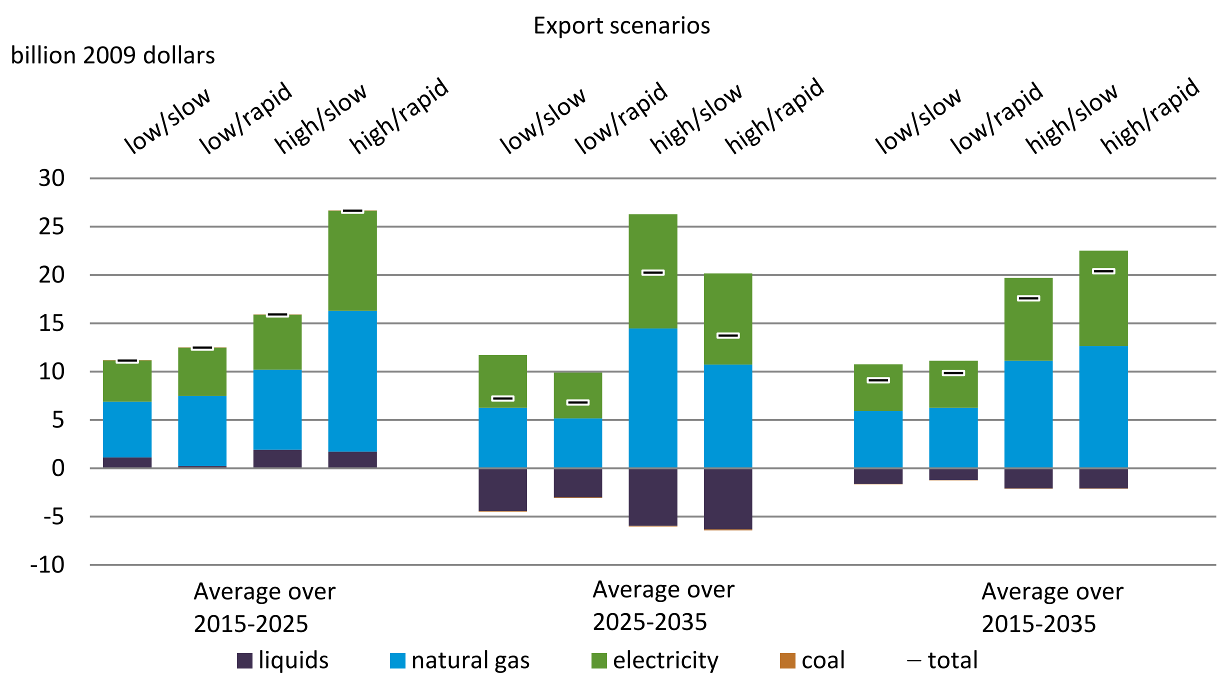
If exports to Canada and Mexico were allowed to vary under these additional export scenarios, they would likely respond similarly to domestic consumption and decrease in response to higher natural gas prices.

End-use energy expenditures

The AEO2011 Reference case projects annual average end-use energy expenditures of $1,490 billion over the 2015-2035 period. Of that, $975 billion per year is spent on liquids, $368 billion on electricity bills, $140 billion on natural gas bills, and $7 billion on coal expenditures.

From an end-user perspective in the scenarios with additional gas exports, consumers will consume less and pay more on both their natural gas and electricity bill, and generally a little less for liquid fuels (Figure 7). Under Reference case conditions, increased end-use expenditures on natural gas as a result of additional exports average about 56 percent of the total additional expenditures for natural gas and electricity combined. For example, under Reference case conditions in the low/slow scenario, end-use consumers together are expected to increase their total energy expenditures by $9 billion per year, or 0.6 percent on average from 2015 to 2035. Under the high/rapid scenarios, consumed total energy expenditures increase by $20 billion per year, or 1.4 percent on average, between 2015 and 2035.

Figure 7. Average change in annual end-use energy expenditures from *AEO2011* Reference case as a result of additional natural gas exports



Source: U.S. Energy Information Administration, National Energy Modeling System

Natural gas expenditures

As discussed earlier, given the lower consumption levels in response to the higher prices from increased exports, the percentage change in the dollars expended by customers for natural gas is less than the percentage change in the delivered prices. In general, the relative pattern of total end-use expenditures across time, export scenarios, and cases, is similar to the relative pattern shown in the wellhead prices in Figures 3 and 4. The higher export volume scenarios result in greater increases in expenditures, while those with rapid export penetration show increases peaking earlier and at higher levels than their slow export penetration counterpart, which show bills increasing more towards the end of the projection period. Under Reference case conditions, the greatest single year increase in total end-use consumer bills is 16 percent, while the lowest single year increase is less than 1 percent. In all but three export scenarios and cases, the higher average increase over the comparable baseline scenario in natural gas bills paid by end-use consumers occurred during the early years. The greatest percentage increase in end-use expenditures over the comparable baseline level in a single year (26 percent) occurs in the high/rapid scenario under the Low Shale EUR case.

On average between 2015 and 2035, total U.S. end-use natural gas expenditures as a result of added exports, under Reference case conditions, increase between $6 billion to $13 billion (between 3 to 9 percent), depending on the export scenario. The Low Shale EUR case shows the greatest average annual increase in end-use natural gas expenditures over the same time period, with increases over the baseline (no additional exports) scenario ranging from $7 billion to $15 billion.

At the sector level, since the natural gas commodity charge represents significantly different portions of each natural gas consuming sector's bill, the degree to which each sector is projected to see their total bill change with added exports varies significantly (Table 1). Natural gas expenditures increase at the highest percentages in the industrial sector, where low transmission and distribution charges constitute a relatively small part of the delivered natural gas price.

Table 1. Change in natural gas expenditures by end use consumers from AEO2011 Reference case with different additional export levels imposed

Sector	Scenario	Average 2015-2025	Average 2025-2035	Average 2015-2035	Maximum Annual Change	Minimum Annual Change
Residential	low/slow	3.2%	3.3%	3.2%	4.7%	0.5%
Residential	low/rapid	4.2%	2.9%	3.6%	5.4%	2.2%
Residential	high/slow	4.4%	7.1%	5.6%	8.9%	0.9%
Residential	high/rapid	8.3%	5.7%	7.0%	10.9%	2.5%
Commercial	low/slow	3.2%	3.2%	3.2%	4.8%	0.6%
Commercial	low/rapid	4.3%	2.7%	3.5%	5.8%	2.0%
Commercial	high/slow	4.6%	6.9%	5.6%	8.9%	0.9%
Commercial	high/rapid	8.3%	5.4%	6.9%	11.4%	2.7%
Industrial	low/slow	7.2%	5.8%	6.4%	11.1%	1.2%
Industrial	low/rapid	9.4%	4.6%	7.1%	14.0%	3.5%
Industrial	high/slow	10.2%	14.7%	12.2%	19.3%	2.0%
Industrial	high/rapid	18.7%	10.4%	14.6%	26.9%	5.2%

Source: U.S. Energy Information Administration, National Energy Modeling System

The results in Table 1 do not reflect changes in natural gas expenditures in the electric power sector. The projected overall decrease in natural gas use by generators is significant enough to result in a decrease in natural gas expenditures for that sector, largely during 2015-2025. However, electric generators will see an increase in their overall costs of power generation that will be reflected in higher electricity bills for consumers.

Electricity expenditures

On average across the projection period, electricity prices under Reference case conditions increase by between 0.14 and 0.29 cents per kilowatthour (kWh) (between 2 and 3 percent) when gas exports are added. The greatest increase in the electricity price occurs in 2019 under the Low Shale EUR case for the high export/rapid growth export scenario, with an increase of 0.85 cents per kWh (9 percent).

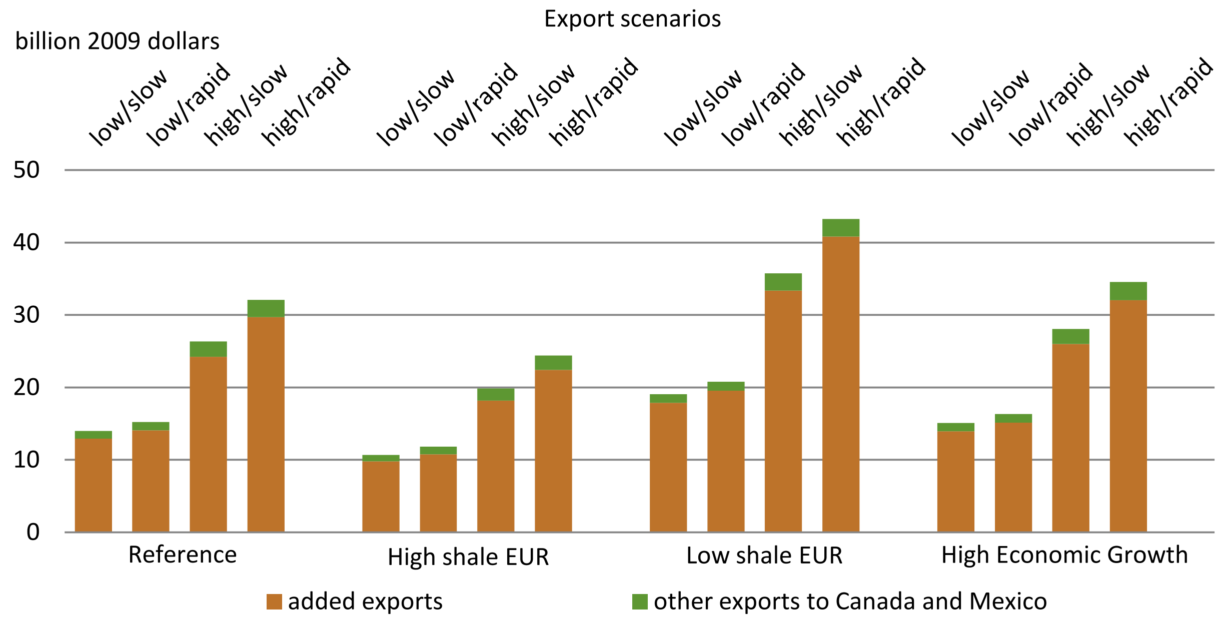
Similar to natural gas, higher electricity prices due to the increased exports reduce end-use consumption making the percentage change in end-use electricity expenditures less than the percentage change in delivered electricity prices; additionally, the percentage increase in end-use electricity expenditures will be lower for the residential and commercial sectors and higher for the industrial sector. Under Reference case conditions, the greatest single year increase in total end-use consumer electricity bills is 4 percent, while the lowest single year increase is negligible. The greatest percentage increase in end-use electricity expenditures over the comparable baseline level in a single year (7 percent) occurs in the high/rapid scenario under the Low Shale EUR case.

On average between 2015 and 2035, total U.S. end-use electricity expenditures as a result of added exports, under Reference case conditions, increase between $5 billion to $10 billion (between 1 to 3 percent), depending on the export scenario. The High Macroeconomic Growth case shows the greatest average annual increase in natural gas expenditures over the same time period, with increases over the baseline (no additional exports) scenario ranging from $6 billion to $12 billion.

Natural gas producer revenues

Total additional natural gas revenues to producers from exports increase on an average annual basis from 2015 to 2035 between $14 billion and $32 billion over the *AEO2011* Reference case, depending on the export scenario (Figure 8). These revenues largely come from the added exports defining the scenarios, as well as other exports to Canada and Mexico in the model that see higher prices under the additional export scenarios, even though the volumes are assumed not to vary. Revenues associated with the added exports reflect dollars spent to purchase and move the natural gas to the export facility, but do not include any revenues associated with the liquefaction and shipping process. The Low Shale EUR case shows the greatest average annual increase in revenues over the 2015 to 2035 time period, with revenues ranging from over $19 billion to $43 billion, due to the relatively high natural gas wellhead prices in that case. These figures represent increased revenues, not profits. A large portion of the additional export revenues will cover the increased costs associated with supplying the increased level of production required when natural gas exports are increased, such as for equipment (e.g., drilling rigs) and labor. In contrast, the additional revenues resulting from the higher price of natural gas that would have been produced and sold to largely domestic customers even in the absence of the additional exports posited in the analysis scenarios would preponderantly reflect increased profits for producers and resource owners.

Figure 8. Average annual increase in domestic natural gas export revenues from indicated baseline case (no additional exports) with different additional export levels imposed, 2015-2035



Source: U.S. Energy Information Administration, National Energy Modeling System

Impacts beyond the natural gas industry

While the natural gas industry would be directly impacted by increased exports, there are indirect impacts on other energy sectors. The electric generation industry shows the largest impact, followed by the coal industry.

As discussed earlier, higher natural gas prices lead electric generators to burn more coal and less natural gas. Coal producers benefit from the increased coal demand. On average, from 2015 to 2035, coal minemouth prices, production, and revenues increase by at most 1.1, 5.5, and 6.2 percent, respectively, across the increased export scenarios applied to all cases.

Domestic petroleum production in the form of lease condensate and natural gas plant liquids also rises due to increased natural gas drilling. For example, under Reference case conditions, in the scenario with the greatest overall response (high/rapid exports), total domestic energy production is 4.13 quadrillion British thermal units (Btu) per year (4.7 percent), which is greater on average from 2015 to 2035 than in the baseline scenario, while total domestic energy consumption is only 0.12 quadrillion Btu (0.1 percent) lower.

Effects on non-energy sectors, other than impacts on their energy expenditures, are generally beyond the scope of this report for reasons described previously.

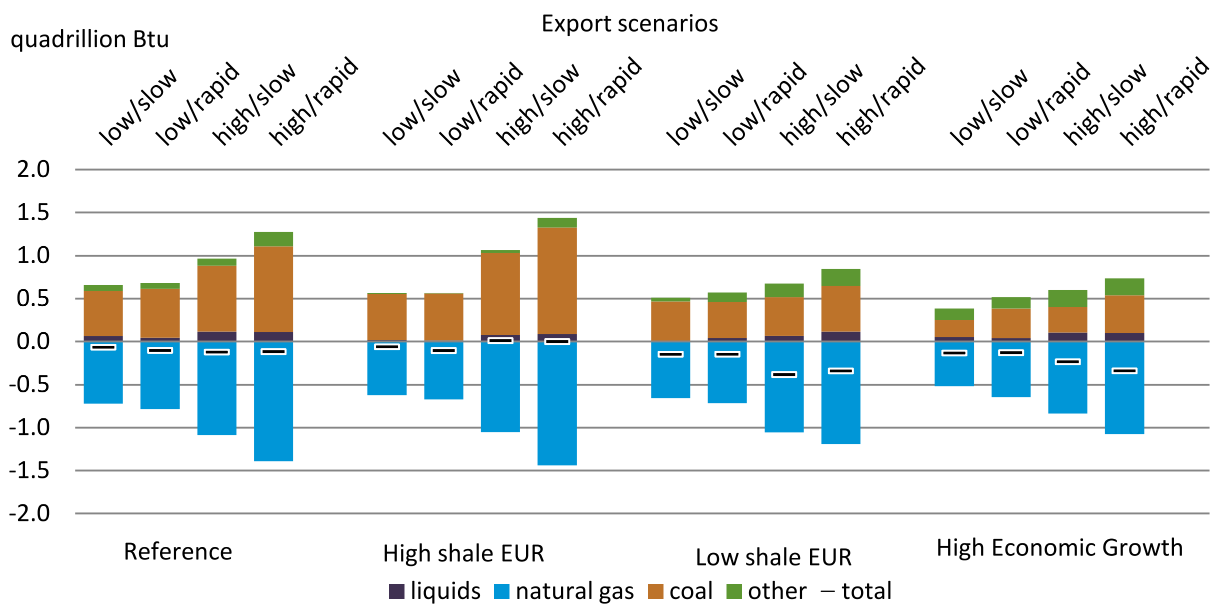
Total energy use and energy-related carbon dioxide emissions

Annual primary energy consumption in the AEO2011 Reference case, measured in Btu, averages 108 quadrillion Btu between 2015 and 2035, with a growth rate of 0.6 percent. Cumulative carbon dioxide (CO_2) emissions total 125,000 million metric tons for that twenty-year period.

The changes in overall energy consumption across scenarios and cases are largely reflective of what occurs in the electric power sector. While additional exports result in decreased natural gas consumption, changes in overall energy consumption are relatively minor as much of the decrease in natural gas consumption is replaced with increased coal consumption (Figure 9). In fact, in some of the earlier years total energy consumption increases with added exports since directly replacing natural gas with coal in electricity generation requires more Btu, as the heat rates (Btu per kWh) for coal generators exceed those for natural gas generators.

On average from 2015 to 2035 under Reference case conditions, decreased natural gas consumption as a result of added exports are countered proportionately by increased coal consumption (72 percent), increased liquid fuel consumption (8 percent), other increased consumption, such as from renewable generation sources (9 percent), and decreases in total consumption (11 percent). In the earlier years, the amount of natural gas to coal switching is greater, and coal plays a more dominant role in replacing the decreased levels of natural gas consumption, which also tend to be greater in the earlier years. Switching from natural gas to coal is less significant in later years, partially as a result of a greater proportion of switching into renewable generation. As a result decreased natural gas consumption from added exports more directly results in decreased total energy consumption via the end-use consumer cutting back energy use in response to higher prices. This basic pattern similarly occurs under the Low Shale EUR and High Economic Growth cases – less switching from natural gas into coal and more into renewable than under Reference case conditions, as well as greater decreases in total energy consumption as a result of added exports.

Figure 9. Average annual change from indicated baseline case (no additional exports) in total primary energy consumed with different additional export levels imposed, 2015-2035



Source: U.S. Energy Information Administration, National Energy Modeling System
Note: Other includes renewable and nuclear generation.

While lower domestic natural gas deliveries resulting from added exports reduce natural gas related CO_2 emissions, the increased use of coal in the electric sector generally results in a net increase in overall

CO_2 emissions. The exceptions occur in environments when renewables are better able to compete against natural gas and coal. However, when also accounting for emissions related to natural gas used in the liquefaction process, additional exports increase CO_2 levels under all cases and export scenarios, particularly in the earlier years of the projection period. Table 2 displays the cumulative CO_2 emissions levels from 2015 to 2035 in all cases and scenarios, with the change relative to the associated baseline case.

Table 2. Cumulative CO_2 emissions from 2015 to 2035 associated with additional natural gas export levels imposed (million metric tons CO_2 and percentage)

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

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

Appendix A. Request Letter

Department of Energy
Washington, DC 20585
August 15, 2011

MEMORANDUM

TO: HOWARD K. GRUENSPECHT
ACTING ADMINISTRATOR
ENERGY INFORMATION ADMINISTRATION

FROM: CHARLES D. MCCONNELL
CHIEF OPERATING OFFICER
OFFICE OF FOSSIL ENERGY

SUBJECT: **ACTION:** Request for EIA to Perform a Domestic Natural Gas Export Case Study

ISSUE: The Department of Energy's (DOE) Office of Fossil Energy (FE) must determine whether exports of liquefied natural gas (LNG) to non-free trade agreement countries are not inconsistent with the public interest. An independent case study analysis of the impact of increased domestic natural gas demand, as exports, under different incremental demand scenarios, performed by the Energy Information Administration (EIA) will be useful to assist DOE/FE in making future public interest determinations.

BACKGROUND: DOE/FE has been delegated the statutory responsibility under section 3 of the Natural Gas Act (NGA) (15 U.S.C. § 717b) to evaluate and approve or deny applications to import and export natural gas and liquefied natural gas to or from the United States. Applications to DOE/FE to export natural gas and LNG to non-free trade agreement countries are reviewed under section 3(a) of the NGA, under which FE must determine if the proposed export arrangements meet the public interest requirements of section 3 of the NGA.

To-date, DOE/FE has received applications for authority to export domestically produced LNG by vessel from three proposed liquefaction facilities, one application to export LNG by ISO containers on cargo carriers, and additional applications could be submitted by others in the future. Applications submitted to DOE/FE total 5.6 billion cubic feet per day (Bcf/day) of natural gas to be exported from the United States, equal to over 8 percent of U.S. natural gas consumption in 2015 compared to the EIA reference case projection of 68.8 Bcf/day in 2015.[1]

Studies and analyses submitted with, and in support of, LNG export applications to DOE/FE evaluated the impact LNG exports could have on domestic natural gas supply,

[1] EIA *Annual Energy Outlook 2011 (AEO2011)*

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demand and market prices. It would be helpful in DOE/FE reviews of these applications, and other potential applications, to understand the implications of additional natural gas demand (as exports) on domestic energy consumption, production, and prices under different scenarios.

Understanding that the domestic natural gas market is sensitive to a number of factors, including those highlighted on page 37 of the *AEO2011*, we request that EIA include sensitivity cases to explore some of these uncertainties, using the modeling analysis presented in the *AEO2011* as a starting point. The results of this study will be beneficial to DOE/FE by providing an independent assessment of how increased natural gas exports could affect domestic markets, and could be used in making future public interest determinations. The specific request of the study is provided in the attachment. We would like to receive the study, along with an analysis and commentary of the results by October 2011, and recognize that the study may be made available on EIA's website.

We are available to further discuss the study with your staff as they begin the study to clarify any issues associated with this request as needed.

RECOMMENDATION: That you approve this request.

APPROVE:______________ DISAPPROVE: ________________ DATE: _______

ATTACHMENTS:
Impact of Higher Demand for U.S. Natural Gas on Domestic Energy Markets
Background: (15 U.S.C. § 717b)

Impact of Higher Demand for U.S. Natural Gas on Domestic Energy Markets

The Office of Fossil Energy (FE) requests the Energy Information Administration (EIA) to evaluate the impact of increased natural gas demand, reflecting possible exports of U.S. natural gas, on domestic energy markets using the modeling analysis presented in the *Annual Energy Outlook 2011 (AEO2011)* as a starting point. In discussions with EIA we learned that EIA's National Energy Modeling System is not designed to capture the impact of increased export-driven demand for natural gas on economy-wide economic indicators such as gross domestic product and employment, and that it does not include a representation of global natural gas markets. Therefore, EIA should focus its analysis on the implications of additional natural gas demand on domestic energy consumption, production, and prices.

The study should address scenarios reflecting export-related increases in natural gas demand of between 6 billion cubic feet per day (Bcf/d) and 12 Bcf/d that are phased in at rates of between 1 Bcf/d per year and 3 Bcf/d per year starting in 2015. Understanding that the domestic natural gas market is sensitive to a number of factors, including those highlighted on page 37 of the *AEO2011*, we request that EIA include sensitivity cases to explore some of these uncertainties. We are particularly interested in sensitivity cases relating to alternative recovery economics for shale gas resources, as in the *AEO2011 Low and High Shale EUR* cases, and a sensitivity case with increased baseline natural gas demand as in the *AEO2011 High Economic Growth* case.

The study report should review and synthesize the results obtained in the modeling work and include, as needed, discussions of context, caveats, issues and limitations that are relevant to the study. Please include tables or figures that summarize impacts on annual domestic natural gas prices, domestic natural gas production and consumption levels, domestic expenditures for natural gas and other relevant fuels, and revenues associated with the incremental export demand for natural gas. The standard *AEO 2011* reporting tables should also be provided, with the exception of tables reporting information that EIA considers to be spurious or misleading given the limitations of its modeling tools in addressing the study questions.

We would like to receive the completed analysis by October 2011 and recognize that EIA may post the study on its website after providing it to us.

Thank you for your attention to this request. Please do not hesitate to contact me (Charles D. McConnell) or John Anderson at 6-0521, if you have any questions.

Source: http://uscode.house.gov/download/pls/15C15B.txt

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-CITE-
    15 USC Sec. 717b                                            01/07/2011

-EXPCITE-
    TITLE 15 - COMMERCE AND TRADE
    CHAPTER 15B - NATURAL GAS

-HEAD-
    Sec. 717b. Exportation or importation of natural gas; LNG terminals

-STATUTE-
    (a) Mandatory authorization order
      After six months from June 21, 1938, no person shall export any
    natural gas from the United States to a foreign country or import
    any natural gas from a foreign country without first having secured
    an order of the Commission authorizing it to do so. The Commission
    shall issue such order upon application, unless, after opportunity
    for hearing, it finds that the proposed exportation or importation
    will not be consistent with the public interest. The Commission may
    by its order grant such application, in whole or in part, with such
    modification and upon such terms and conditions as the Commission
    may find necessary or appropriate, and may from time to time, after
    opportunity for hearing, and for good cause shown, make such
    supplemental order in the premises as it may find necessary or
    appropriate.
    (b) Free trade agreements
      With respect to natural gas which is imported into the United
    States from a nation with which there is in effect a free trade
    agreement requiring national treatment for trade in natural gas,
    and with respect to liquefied natural gas -
        (1) the importation of such natural gas shall be treated as a
      "first sale" within the meaning of section 3301(21) of this
      title; and
        (2) the Commission shall not, on the basis of national origin,
      treat any such imported natural gas on an unjust, unreasonable,
      unduly discriminatory, or preferential basis.
    (c) Expedited application and approval process
      For purposes of subsection (a) of this section, the importation
    of the natural gas referred to in subsection (b) of this section,
    or the exportation of natural gas to a nation with which there is
    in effect a free trade agreement requiring national treatment for
    trade in natural gas, shall be deemed to be consistent with the
    public interest, and applications for such importation or
    exportation shall be granted without modification or delay.
    (d) Construction with other laws
      Except as specifically provided in this chapter, nothing in this
    chapter affects the rights of States under -
        (1) the Coastal Zone Management Act of 1972 (16 U.S.C. 1451 et
      seq.);
        (2) the Clean Air Act (42 U.S.C. 7401 et seq.); or
        (3) the Federal Water Pollution Control Act (33 U.S.C. 1251 et
      seq.).
    (e) LNG terminals
      (1) The Commission shall have the exclusive authority to approve
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or deny an application for the siting, construction, expansion, or operation of an LNG terminal. Except as specifically provided in this chapter, nothing in this chapter is intended to affect otherwise applicable law related to any Federal agency's authorities or responsibilities related to LNG terminals.

(2) Upon the filing of any application to site, construct, expand, or operate an LNG terminal, the Commission shall -

(A) set the matter for hearing;

(B) give reasonable notice of the hearing to all interested persons, including the State commission of the State in which the LNG terminal is located and, if not the same, the Governor-appointed State agency described in section 717b-1 of this title;

(C) decide the matter in accordance with this subsection; and

(D) issue or deny the appropriate order accordingly.

(3)(A) Except as provided in subparagraph (B), the Commission may approve an application described in paragraph (2), in whole or part, with such modifications and upon such terms and conditions as the Commission find (!1) necessary or appropriate.

(B) Before January 1, 2015, the Commission shall not -

(i) deny an application solely on the basis that the applicant proposes to use the LNG terminal exclusively or partially for gas that the applicant or an affiliate of the applicant will supply to the facility; or

(ii) condition an order on -

(I) a requirement that the LNG terminal offer service to customers other than the applicant, or any affiliate of the applicant, securing the order;

(II) any regulation of the rates, charges, terms, or conditions of service of the LNG terminal; or

(III) a requirement to file with the Commission schedules or contracts related to the rates, charges, terms, or conditions of service of the LNG terminal.

(C) Subparagraph (B) shall cease to have effect on January 1, 2030.

(4) An order issued for an LNG terminal that also offers service to customers on an open access basis shall not result in subsidization of expansion capacity by existing customers, degradation of service to existing customers, or undue discrimination against existing customers as to their terms or conditions of service at the facility, as all of those terms are defined by the Commission.

(f) Military installations

(1) In this subsection, the term "military installation" -

(A) means a base, camp, post, range, station, yard, center, or homeport facility for any ship or other activity under the jurisdiction of the Department of Defense, including any leased facility, that is located within a State, the District of Columbia, or any territory of the United States; and

(B) does not include any facility used primarily for civil works, rivers and harbors projects, or flood control projects, as determined by the Secretary of Defense.

(2) The Commission shall enter into a memorandum of understanding

with the Secretary of Defense for the purpose of ensuring that the Commission coordinate and consult (!2) with the Secretary of Defense on the siting, construction, expansion, or operation of liquefied natural gas facilities that may affect an active military installation.

(3) The Commission shall obtain the concurrence of the Secretary of Defense before authorizing the siting, construction, expansion, or operation of liquefied natural gas facilities affecting the training or activities of an active military installation.

-SOURCE-

(June 21, 1938, ch. 556, Sec. 3, 52 Stat. 822; Pub. L. 102-486, title II, Sec. 201, Oct. 24, 1992, 106 Stat. 2866; Pub. L. 109-58, title III, Sec. 311(c), Aug. 8, 2005, 119 Stat. 685.)

-REFTEXT-

REFERENCES IN TEXT

The Coastal Zone Management Act of 1972, referred to in subsec. (d)(1), is title III of Pub. L. 89-454 as added by Pub. L. 92-583, Oct. 27, 1972, 86 Stat. 1280, as amended, which is classified generally to chapter 33 (Sec. 1451 et seq.) of Title 16, Conservation. For complete classification of this Act to the Code, see Short Title note set out under section 1451 of Title 16 and Tables.

The Clean Air Act, referred to in subsec. (d)(2), is act July 14, 1955, ch. 360, 69 Stat. 322, as amended, which is classified generally to chapter 85 (Sec. 7401 et seq.) of Title 42, The Public Health and Welfare. For complete classification of this Act to the Code, see Short Title note set out under section 7401 of Title 42 and Tables.

The Federal Water Pollution Control Act, referred to in subsec. (d)(3), is act June 30, 1948, ch. 758, as amended generally by Pub. L. 92-500, Sec. 2, Oct. 18, 1972, 86 Stat. 816, which is classified generally to chapter 26 (Sec. 1251 et seq.) of Title 33, Navigation and Navigable Waters. For complete classification of this Act to the Code, see Short Title note set out under section 1251 of Title 33 and Tables.

-MISC1-

AMENDMENTS

2005 - Pub. L. 109-58, Sec. 311(c)(1), inserted "; LNG terminals" after "natural gas" in section catchline.

Subsecs. (d) to (f). Pub. L. 109-58, Sec. 311(c)(2), added subsecs. (d) to (f).

1992 - Pub. L. 102-486 designated existing provisions as subsec. (a) and added subsecs. (b) and (c).

-TRANS-

TRANSFER OF FUNCTIONS

Enforcement functions of Secretary or other official in Department of Energy and Commission, Commissioners, or other official in Federal Energy Regulatory Commission related to compliance with authorizations for importation of natural gas from Alberta as pre-deliveries of Alaskan gas issued under this section with respect to pre-construction, construction, and initial operation of transportation system for Canadian and Alaskan natural gas transferred to the Federal Inspector, Office of Federal Inspector for Alaska Natural Gas Transportation System, until first anniversary of date of initial operation of Alaska Natural Gas Transportation System, see Reorg. Plan No. 1 of 1979, Secs. 102(d), 203(a), 44 F.R. 33663, 33666, 93 Stat. 1373, 1376, effective July 1, 1979, set out under section 719e of this title. Office of Federal Inspector for the Alaska Natural Gas Transportation System abolished and functions and authority vested in Inspector transferred to Secretary of Energy by section 3012(b) of Pub. L. 102-486, set out as an Abolition of Office of Federal Inspector note under section 719e of this title. Functions and authority vested in Secretary of Energy subsequently transferred to Federal Coordinator for Alaska Natural Gas Transportation Projects by section 720d(f) of this title.

DELEGATION OF FUNCTIONS

Functions of President respecting certain facilities constructed and maintained on United States borders delegated to Secretary of State, see Ex. Ord. No. 11423, Aug. 16, 1968, 33 F.R. 11741, set out as a note under section 301 of Title 3, The President.

-EXEC-

EX. ORD. NO. 10485. PERFORMANCE OF FUNCTIONS RESPECTING ELECTRIC POWER AND NATURAL GAS FACILITIES LOCATED ON UNITED STATES BORDERS

Ex. Ord. No. 10485. Sept. 3, 1953, 18 F.R. 5397, as amended by Ex. Ord. No. 12038, Feb. 3, 1978, 43 F.R. 4957, provided:

Section 1. (a) The Secretary of Energy is hereby designated and empowered to perform the following-described functions:

(1) To receive all applications for permits for the construction, operation, maintenance, or connection, at the borders of the United States, of facilities for the transmission of electric energy between the United States and a foreign country.

(2) To receive all applications for permits for the construction, operation, maintenance, or connection, at the borders of the United States, of facilities for the exportation or importation of natural gas to or from a foreign country.

(3) Upon finding the issuance of the permit to be consistent with the public interest, and, after obtaining the favorable recommendations of the Secretary of State and the Secretary of Defense thereon, to issue to the applicant, as appropriate, a permit for such construction, operation, maintenance, or connection. The Secretary of Energy shall have the power to attach to the issuance of the permit and to the exercise of the rights granted thereunder such conditions as the public interest may in its judgment require.

(b) In any case wherein the Secretary of Energy, the Secretary of State, and the Secretary of Defense cannot agree as to whether or not a permit should be issued, the Secretary of Energy shall submit to the President for approval or disapproval the application for a permit with the respective views of the Secretary of Energy, the Secretary of State and the Secretary of Defense.

Sec. 2. [Deleted.]

Sec. 3. The Secretary of Energy is authorized to issue such rules and regulations, and to prescribe such procedures, as it may from time to time deem necessary or desirable for the exercise of the authority delegated to it by this order.

Sec. 4. All Presidential Permits heretofore issued pursuant to Executive Order No. 8202 of July 13, 1939, and in force at the time of the issuance of this order, and all permits issued hereunder, shall remain in full force and effect until modified or revoked by the President or by the Secretary of Energy.

Sec. 5. Executive Order No. 8202 of July 13, 1939, is hereby revoked.

-FOOTNOTE-

(!1) So in original. Probably should be "finds".

(!2) So in original. Probably should be "coordinates and consults".

-End-

Appendix B. Summary Tables

Table B1. U.S. Annual Average Values from 2015 to 2025

	Reference					High Shale EUR					Low Shale EUR					High Macroeconomic Growth				
	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																				
Net Exports	(1.90)	(0.29)	0.11	0.17	1.74	(1.32)	0.32	0.70	0.79	2.35	(2.72)	(1.17)	(0.88)	(0.73)	0.66	(2.00)	(0.38)	0.01	0.07	1.64
gross imports	3.62	3.70	3.70	3.74	3.76	3.19	3.25	3.26	3.27	3.31	4.27	4.42	4.53	4.48	4.68	3.70	3.78	3.79	3.82	3.85
gross exports	1.72	3.41	3.81	3.91	5.50	1.87	3.56	3.96	4.06	5.65	1.56	3.25	3.65	3.75	5.34	1.70	3.39	3.79	3.89	5.49
Dry Production	23.27	24.15	24.37	24.42	25.33	26.24	27.28	27.51	27.57	28.41	19.80	20.72	20.78	20.99	21.83	23.85	24.90	25.10	25.22	26.20
shale gas	8.34	8.96	9.17	9.13	9.90	11.90	12.66	12.87	12.89	13.64	3.88	4.42	4.63	4.53	5.22	8.73	9.49	9.70	9.69	10.51
other	14.93	15.18	15.20	15.29	15.43	14.34	14.61	14.65	14.68	14.77	15.91	16.30	16.15	16.45	16.62	15.12	15.41	15.39	15.53	15.70
Delivered Volumes (1)	23.34	22.57	22.38	22.37	21.68	25.58	24.94	24.79	24.75	24.00	20.82	20.13	19.90	19.94	19.35	23.99	23.37	23.17	23.22	22.60
electric generators	6.81	6.25	6.16	6.11	5.67	8.35	7.94	7.88	7.80	7.30	5.07	4.66	4.55	4.54	4.23	6.99	6.63	6.53	6.54	6.21
industrial	8.14	8.01	7.95	7.98	7.83	8.55	8.40	8.34	8.37	8.19	7.74	7.58	7.51	7.56	7.38	8.50	8.34	8.27	8.30	8.12
residential	4.83	4.80	4.79	4.79	4.75	4.94	4.92	4.90	4.91	4.87	4.68	4.63	4.61	4.62	4.57	4.90	4.86	4.85	4.85	4.81
commercial	3.48	3.44	3.42	3.42	3.37	3.65	3.61	3.59	3.60	3.55	3.27	3.20	3.17	3.18	3.11	3.52	3.46	3.45	3.45	3.39
NATURAL GAS END-USE PRICES (2009$/Mcf)																				
residential	11.19	11.63	11.77	11.81	12.33	9.92	10.24	10.37	10.36	10.72	13.23	14.05	14.27	14.42	15.10	11.56	12.09	12.21	12.29	12.87
commercial	9.23	9.66	9.79	9.83	10.34	7.97	8.28	8.40	8.39	8.74	11.27	12.09	12.31	12.46	13.16	9.60	10.12	10.24	10.31	10.88
industrial	5.59	6.10	6.25	6.32	6.91	4.41	4.80	4.95	4.94	5.41	7.50	8.40	8.62	8.83	9.59	5.89	6.49	6.63	6.73	7.41
OTHER PRICES																				
Natural Gas Wellhead Price (2009$/Mcf)	4.70	5.17	5.30	5.37	5.91	3.56	3.90	4.02	4.03	4.42	6.52	7.41	7.63	7.84	8.64	4.99	5.54	5.66	5.77	6.39
Henry Hub Price (2009$/MMBtu)	5.17	5.69	5.83	5.91	6.51	3.92	4.29	4.43	4.43	4.87	7.18	8.16	8.41	8.64	9.51	5.49	6.10	6.23	6.35	7.04
Coal Minemouth Price (2009$/short-ton)	32.67	32.76	32.89	32.89	32.89	32.33	32.69	32.52	32.59	32.77	32.91	33.15	33.10	32.97	33.04	33.23	33.18	33.06	33.33	33.28
End-Use Electricity Price (2009 cents/KWh)	8.85	8.98	9.00	9.02	9.17	8.56	8.62	8.67	8.64	8.70	9.44	9.64	9.71	9.78	9.97	9.08	9.26	9.27	9.32	9.46
NATURAL GAS REVENUES (B 2009$)																				
Export Revenues (2)	9.47	20.64	23.25	25.10	37.74	7.51	16.01	18.17	19.27	28.89	12.83	29.03	32.72	36.09	53.91	10.04	22.11	24.82	26.97	40.81
Domestic Supply Revenues (3)	160.19	175.25	179.33	181.70	199.21	147.33	159.55	163.65	164.23	177.50	177.88	201.92	206.65	213.21	236.34	171.34	190.13	193.88	197.79	218.78
production revenues (4)	109.53	125.29	129.41	132.23	150.47	93.68	106.70	111.00	111.90	126.30	129.24	154.00	158.75	165.84	189.27	119.39	138.71	142.53	146.83	168.64
delivery revenues (5)	50.65	49.97	49.92	49.46	48.74	53.65	52.85	52.65	52.33	51.20	48.64	47.92	47.91	47.37	47.07	51.94	51.41	51.36	50.96	50.14
Import Revenues (6)	17.44	19.22	19.72	19.92	21.97	12.09	13.35	13.86	13.83	15.35	28.00	31.62	33.03	33.32	36.58	18.96	21.07	21.66	21.94	24.19
END-USE ENERGY EXPENDITURES (B 2009$)	1,398.11	1,409.25	1,410.59	1,414.03	1,424.75	1,368.25	1,375.50	1,377.65	1,379.69	1,386.87	1,448.36	1,465.24	1,469.02	1,473.83	1,482.50	1,485.34	1,498.28	1,499.67	1,504.03	1,514.65
liquids	913.43	914.55	913.66	915.34	915.15	908.98	909.65	908.67	911.23	911.57	920.92	921.56	921.21	920.98	916.83	971.80	971.63	971.22	972.09	970.98
natural gas	128.00	133.77	135.27	136.30	142.58	113.26	117.51	119.11	119.24	123.94	151.16	161.03	163.24	165.90	173.42	136.49	143.47	144.71	146.37	153.61
electricity	349.77	354.03	354.76	355.46	360.10	339.21	341.51	343.06	342.39	344.53	369.28	375.68	377.60	379.98	385.31	369.58	375.70	376.28	378.08	382.59
coal	6.90	6.91	6.91	6.93	6.92	6.80	6.82	6.81	6.83	6.83	6.99	6.98	6.97	6.97	6.94	7.47	7.49	7.46	7.49	7.46
END-USE ENERGY CONSUMPTION (quadrillion Btu)	67.88	67.68	67.59	67.67	67.37	68.58	68.40	68.28	68.37	68.11	66.93	66.63	66.49	66.54	66.20	70.23	70.02	69.89	69.98	69.64
liquids	36.71	36.74	36.74	36.78	36.78	36.67	36.71	36.71	36.74	36.75	36.71	36.72	36.71	36.74	36.73	38.13	38.18	38.16	38.20	38.20
natural gas	16.04	15.85	15.76	15.81	15.55	16.76	16.55	16.45	16.49	16.23	15.22	14.97	14.86	14.91	14.65	16.49	16.26	16.16	16.21	15.92
electricity	13.44	13.41	13.41	13.41	13.37	13.48	13.47	13.46	13.48	13.47	13.32	13.26	13.24	13.22	13.16	13.84	13.81	13.80	13.79	13.75
coal	1.68	1.68	1.68	1.68	1.67	1.67	1.67	1.67	1.67	1.67	1.68	1.68	1.68	1.68	1.67	1.77	1.77	1.77	1.77	1.76
ELECTRIC GENERATION (billion kWh)	4,456.38	4,441.98	4,437.47	4,441.10	4,422.62	4,492.78	4,484.65	4,477.63	4,483.35	4,471.75	4,391.20	4,369.32	4,360.19	4,356.29	4,329.07	4,594.62	4,577.41	4,572.19	4,572.39	4,552.42
coal	1,921.25	1,982.85	1,995.33	1,999.09	2,044.09	1,756.51	1,808.90	1,813.78	1,828.74	1,885.58	2,093.76	2,132.35	2,134.49	2,123.82	2,139.82	2,004.09	2,036.83	2,052.54	2,043.09	2,073.78
gas	999.19	918.42	902.15	898.01	829.83	1,232.25	1,170.15	1,158.31	1,147.99	1,070.38	733.83	671.33	653.23	655.42	608.52	1,036.47	978.19	959.84	964.71	909.63
nuclear	866.34	866.34	866.34	866.34	866.34	850.50	850.50	850.50	851.17	855.05	866.34	866.34	866.34	866.34	866.34	866.34	866.34	866.34	866.34	866.34
renewables	610.16	614.27	613.17	617.16	621.29	593.01	594.47	595.24	594.57	599.35	636.27	638.25	645.09	648.70	651.89	626.90	634.74	632.26	636.59	641.06
other	59.43	60.11	60.48	60.50	61.08	60.51	60.63	59.80	60.87	61.39	61.00	61.04	61.03	62.00	62.50	60.83	61.30	61.21	61.65	61.61
PRIMARY ENERGY (quadrillion Btu)																				
Consumption	104.89	104.90	104.87	104.98	104.91	105.24	105.25	105.14	105.32	105.27	104.34	104.16	104.07	104.06	103.75	108.35	108.31	108.25	108.36	108.12
Imports	28.62	28.75	28.72	28.78	28.90	27.69	27.73	27.77	27.87	27.94	29.78	29.83	29.92	29.98	30.08	30.06	30.22	30.21	30.24	30.28
Exports	7.06	8.76	9.15	9.26	10.86	7.20	8.92	9.32	9.43	11.03	6.85	8.54	8.93	9.01	10.60	7.10	8.80	9.20	9.30	10.90
Production	83.14	84.73	85.12	85.28	86.71	84.63	86.34	86.60	86.79	88.26	81.15	82.63	82.84	82.86	84.05	85.16	86.66	87.01	87.18	88.52
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	5,793.73	5,832.23	5,837.67	5,846.39	5,869.62	5,754.36	5,787.50	5,787.31	5,804.76	5,833.35	5,832.09	5,853.23	5,846.94	5,841.58	5,843.35	6,017.09	6,037.23	6,043.12	6,043.12	6,055.08

Table B2. Differential from Base in U.S. Average Annual Values from 2015 to 2025 when Exports are Added

	Reference				High Shale EUR				Low Shale EUR				High Macroeconomic Growth			
	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																
Net Exports	1.61	2.00	2.07	3.64	1.64	2.02	2.11	3.67	1.55	1.84	1.99	3.38	1.62	2.01	2.07	3.64
gross imports	0.08	0.09	0.12	0.15	0.05	0.07	0.08	0.12	0.14	0.25	0.20	0.41	0.07	0.08	0.12	0.14
gross exports	1.69	2.09	2.19	3.78	1.69	2.09	2.19	3.78	1.69	2.09	2.19	3.78	1.69	2.09	2.19	3.78
Dry Production	0.87	1.09	1.15	2.05	1.04	1.28	1.33	2.17	0.92	0.98	1.19	2.04	1.05	1.24	1.37	2.35
shale gas	0.62	0.82	0.79	1.55	0.77	0.97	0.99	1.74	0.53	0.75	0.65	1.33	0.76	0.97	0.96	1.78
other	0.25	0.27	0.36	0.50	0.27	0.31	0.34	0.43	0.39	0.24	0.54	0.71	0.29	0.27	0.41	0.57
Delivered Volumes (1)	(0.77)	(0.95)	(0.97)	(1.66)	(0.64)	(0.80)	(0.84)	(1.59)	(0.69)	(0.91)	(0.88)	(1.46)	(0.62)	(0.82)	(0.77)	(1.39)
electric generators	(0.57)	(0.66)	(0.71)	(1.15)	(0.42)	(0.47)	(0.55)	(1.05)	(0.41)	(0.52)	(0.53)	(0.84)	(0.36)	(0.46)	(0.45)	(0.78)
industrial	(0.13)	(0.19)	(0.16)	(0.32)	(0.15)	(0.22)	(0.19)	(0.36)	(0.15)	(0.23)	(0.18)	(0.35)	(0.16)	(0.23)	(0.20)	(0.38)
residential	(0.03)	(0.04)	(0.04)	(0.08)	(0.03)	(0.04)	(0.04)	(0.07)	(0.05)	(0.07)	(0.07)	(0.11)	(0.04)	(0.05)	(0.05)	(0.09)
commercial	(0.05)	(0.06)	(0.06)	(0.11)	(0.04)	(0.06)	(0.05)	(0.10)	(0.07)	(0.09)	(0.09)	(0.15)	(0.05)	(0.07)	(0.07)	(0.13)
NATURAL GAS END-USE PRICES (2009$/Mcf)																
residential	0.44	0.58	0.62	1.14	0.32	0.45	0.44	0.80	0.81	1.03	1.18	1.87	0.53	0.65	0.72	1.31
commercial	0.43	0.57	0.61	1.12	0.31	0.43	0.42	0.76	0.82	1.04	1.19	1.89	0.52	0.64	0.71	1.28
industrial	0.51	0.66	0.73	1.32	0.39	0.54	0.54	1.00	0.90	1.13	1.33	2.09	0.61	0.74	0.85	1.52
OTHER PRICES																
Natural Gas Wellhead Price (2009$/Mcf)	0.47	0.60	0.68	1.21	0.33	0.46	0.47	0.86	0.88	1.11	1.32	2.11	0.55	0.67	0.77	1.40
Henry Hub Price (2009$/MMBtu)	0.52	0.66	0.74	1.34	0.37	0.51	0.51	0.95	0.97	1.22	1.46	2.33	0.60	0.74	0.85	1.54
Coal Minemouth Price (2009$/short-ton)	0.09	0.21	0.22	0.22	0.36	0.19	0.26	0.44	0.24	0.19	0.06	0.13	(0.05)	(0.17)	0.11	0.06
End-Use Electricity Price (2009 cents/KWh)	0.13	0.15	0.17	0.31	0.06	0.11	0.08	0.14	0.20	0.27	0.34	0.53	0.17	0.19	0.24	0.38
NATURAL GAS REVENUES (B 2009$)																
Export Revenues (2)	11.17	13.77	15.63	28.26	8.50	10.65	11.75	21.38	16.20	19.89	23.25	41.08	12.07	14.79	16.93	30.78
Domestic Supply Revenues (3)	15.07	19.14	21.51	39.02	12.22	16.32	16.91	30.17	24.04	28.77	35.33	58.46	18.79	22.55	26.46	47.44
production revenues (4)	15.75	19.88	22.70	40.93	13.02	17.31	18.22	32.62	24.76	29.51	36.60	60.03	19.32	23.13	27.44	49.24
delivery revenues (5)	(0.68)	(0.74)	(1.19)	(1.91)	(0.80)	(0.99)	(1.32)	(2.45)	(0.72)	(0.74)	(1.28)	(1.58)	(0.53)	(0.59)	(0.98)	(1.80)
Import Revenues (6)	1.78	2.28	2.48	4.53	1.26	1.77	1.74	3.26	3.62	5.03	5.32	8.58	2.12	2.70	2.99	5.24
END-USE ENERGY EXPENDITURES (B 2009$)	11.15	12.49	15.92	26.65	7.26	9.40	11.44	18.63	16.89	20.67	25.47	34.14	12.94	14.33	18.69	29.31
liquids	1.12	0.22	1.91	1.72	0.68	(0.30)	2.26	2.60	0.64	0.29	0.05	(4.09)	(0.18)	(0.59)	0.29	(0.82)
natural gas	5.76	7.26	8.30	14.58	4.26	5.85	5.98	10.68	9.86	12.07	14.73	22.25	6.98	8.22	9.88	17.12
electricity	4.26	4.99	5.69	10.32	2.31	3.85	3.18	5.32	6.39	8.31	10.70	16.02	6.12	6.70	8.50	13.01
coal	0.01	0.01	0.03	0.02	0.02	0.00	0.03	0.03	(0.00)	(0.01)	(0.01)	(0.04)	0.02	(0.01)	0.02	(0.00)
END-USE ENERGY CONSUMPTION (quadrillion Btu)	(0.20)	(0.29)	(0.21)	(0.50)	(0.18)	(0.30)	(0.21)	(0.47)	(0.30)	(0.44)	(0.38)	(0.73)	(0.22)	(0.34)	(0.26)	(0.60)
liquids	0.03	0.03	0.06	0.06	0.04	0.04	0.07	0.08	0.01	(0.00)	0.03	0.02	0.05	0.03	0.07	0.07
natural gas	(0.19)	(0.28)	(0.23)	(0.49)	(0.22)	(0.32)	(0.27)	(0.53)	(0.25)	(0.36)	(0.31)	(0.57)	(0.24)	(0.34)	(0.28)	(0.57)
electricity	(0.03)	(0.04)	(0.04)	(0.08)	(0.00)	(0.02)	(0.00)	(0.01)	(0.06)	(0.08)	(0.09)	(0.16)	(0.03)	(0.04)	(0.05)	(0.09)
coal	(0.00)	(0.00)	0.00	(0.00)	(0.00)	(0.00)	0.00	(0.00)	(0.00)	(0.01)	(0.00)	(0.01)	(0.00)	(0.00)	0.00	(0.01)
ELECTRIC GENERATION (billion kWh)	(14.39)	(18.91)	(15.27)	(33.75)	(8.13)	(15.15)	(9.43)	(21.02)	(21.89)	(31.02)	(34.92)	(62.13)	(17.21)	(22.43)	(22.23)	(42.20)
coal	61.59	74.07	77.84	122.84	52.39	57.26	72.23	129.07	38.59	40.73	30.06	46.06	32.74	48.46	39.01	69.70
gas	(80.76)	(97.03)	(101.17)	(169.36)	(62.10)	(73.94)	(84.25)	(161.86)	(62.50)	(80.59)	(78.41)	(125.31)	(58.28)	(76.63)	(71.76)	(126.84)
nuclear	-	-	-	-	0.00	0.00	0.67	4.55	(0.00)	-	-	(0.00)	-	-	-	-
renewables	4.10	3.00	7.00	11.12	1.46	2.24	1.57	6.35	1.98	8.82	12.43	15.61	7.85	5.36	9.70	14.17
other	0.67	1.04	1.07	1.64	0.11	(0.71)	0.36	0.88	0.04	0.03	1.00	1.50	0.47	0.38	0.82	0.78
PRIMARY ENERGY (quadrillion Btu)																
Consumption	0.02	(0.02)	0.09	0.02	0.01	(0.09)	0.08	0.03	(0.18)	(0.27)	(0.28)	(0.59)	(0.03)	(0.10)	0.01	(0.23)
Imports	0.13	0.10	0.16	0.28	0.04	0.08	0.18	0.26	0.05	0.14	0.20	0.30	0.16	0.15	0.18	0.22
Exports	1.70	2.09	2.20	3.79	1.72	2.12	2.23	3.83	1.69	2.08	2.16	3.75	1.70	2.10	2.20	3.80
Production	1.59	1.98	2.14	3.58	1.71	1.96	2.16	3.63	1.47	1.69	1.71	2.90	1.50	1.85	2.02	3.36
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	38.50	43.94	52.67	75.90	33.14	32.94	50.39	78.99	21.14	14.85	9.48	11.26	20.14	26.03	26.03	37.99

Table B3. U.S. Annual Average Values from 2025 to 2035

	Reference					High Shale EUR					Low Shale EUR					High Macroeconomic Growth				
	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																				
Net Exports	(0.71)	1.48	1.48	3.52	3.57	0.10	2.16	2.15	4.19	4.20	(2.09)	(0.21)	(0.33)	1.83	1.76	(0.88)	1.29	1.29	3.21	3.38
gross imports	2.98	2.99	2.98	3.10	3.09	2.47	2.60	2.61	2.73	2.75	3.99	4.30	4.42	4.41	4.52	3.09	3.11	3.11	3.35	3.21
gross exports	2.28	4.47	4.47	6.62	6.66	2.57	4.76	4.76	6.91	6.95	1.90	4.09	4.09	6.25	6.28	2.21	4.40	4.40	6.56	6.59
Dry Production	25.07	26.58	26.66	28.08	28.23	28.73	30.16	30.21	31.50	31.51	20.98	22.22	22.24	23.61	23.89	26.84	28.59	28.55	29.99	30.31
shale gas	10.96	12.08	12.10	13.10	13.27	15.51	16.70	16.75	17.75	17.74	5.22	6.06	6.13	6.78	6.97	12.19	13.49	13.47	14.49	14.75
other	14.12	14.49	14.56	14.98	14.96	13.21	13.46	13.47	13.75	13.77	15.76	16.16	16.11	16.83	16.91	14.65	15.10	15.08	15.50	15.56
Delivered Volumes (1)	23.96	23.22	23.29	22.60	22.70	26.63	25.94	26.00	25.19	25.19	21.41	20.69	20.82	19.97	20.27	25.80	25.29	25.26	24.72	24.85
electric generators	7.27	6.87	6.95	6.56	6.66	8.89	8.55	8.65	8.11	8.20	5.78	5.28	5.41	4.82	5.08	8.21	8.04	8.03	7.77	7.93
industrial	8.06	7.82	7.81	7.62	7.60	8.68	8.45	8.42	8.25	8.16	7.47	7.34	7.32	7.20	7.19	8.68	8.43	8.40	8.22	8.18
residential	4.82	4.78	4.78	4.73	4.74	4.95	4.91	4.91	4.88	4.88	4.64	4.61	4.61	4.56	4.58	5.01	4.97	4.97	4.93	4.94
commercial	3.68	3.62	3.62	3.56	3.57	3.91	3.85	3.85	3.80	3.80	3.40	3.36	3.37	3.29	3.32	3.75	3.70	3.71	3.66	3.66
NATURAL GAS END-USE PRICES (2009$/Mcf)																				
residential	12.90	13.45	13.39	14.05	13.85	11.31	11.66	11.68	12.10	11.98	15.49	15.96	15.83	16.76	16.27	13.70	14.13	14.06	14.67	14.51
commercial	10.61	11.15	11.09	11.73	11.54	9.01	9.34	9.36	9.75	9.63	13.24	13.71	13.58	14.53	14.02	11.39	11.80	11.73	12.32	12.15
industrial	6.82	7.43	7.36	8.26	7.98	5.39	5.86	5.88	6.46	6.32	9.30	9.79	9.66	10.69	10.09	7.50	8.05	7.96	8.82	8.59
OTHER PRICES																				
Natural Gas Wellhead Price (2009$/Mcf)	5.88	6.42	6.35	7.14	6.88	4.45	4.82	4.83	5.31	5.17	8.25	8.77	8.68	9.69	9.10	6.52	6.98	6.90	7.67	7.43
Henry Hub Price (2009$/MMBtu)	6.47	7.06	6.99	7.86	7.58	4.90	5.30	5.31	5.85	5.69	9.08	9.66	9.56	10.67	10.02	7.18	7.68	7.60	8.45	8.18
Coal Minemouth Price (2009$/short-ton)	33.46	33.51	33.43	33.68	33.43	33.20	33.45	33.21	33.42	33.25	33.77	34.11	33.89	33.76	33.85	34.30	34.01	33.95	33.99	34.16
End-Use Electricity Price (2009 cents/KWh)	9.02	9.17	9.15	9.36	9.28	8.57	8.65	8.67	8.75	8.69	9.86	9.98	9.94	10.25	10.06	9.50	9.67	9.63	9.90	9.78
NATURAL GAS REVENUES (B 2009$)																				
Export Revenues (2)	12.81	29.82	29.50	50.58	48.98	10.46	23.42	23.49	38.88	38.06	17.38	39.57	38.98	66.69	62.90	14.21	32.48	32.11	54.16	52.87
Domestic Supply Revenues (3)	199.45	221.98	220.95	249.66	244.39	184.30	200.41	201.19	220.08	216.08	222.71	243.85	242.19	276.77	266.61	230.96	254.64	252.33	282.66	278.95
production revenues (4)	147.54	170.77	169.47	200.63	194.52	128.09	145.41	146.06	167.45	162.93	173.25	194.92	193.13	228.66	217.47	175.63	199.91	197.44	230.19	225.48
delivery revenues (5)	51.91	51.21	51.48	49.03	49.87	56.21	55.00	55.13	52.63	53.14	49.47	48.94	49.06	48.11	49.13	55.33	54.74	54.89	52.47	53.47
Import Revenues (6)	18.06	19.89	19.65	22.97	22.09	11.69	13.64	13.75	16.04	15.80	33.87	37.50	37.30	41.19	39.73	20.96	22.75	22.52	26.35	24.99
END-USE ENERGY EXPENDITURES (B 2009$)	1,582.70	1,589.93	1,589.52	1,602.94	1,596.44	1,543.37	1,552.01	1,553.43	1,559.62	1,552.40	1,648.34	1,658.55	1,651.04	1,673.64	1,651.53	1,766.94	1,773.78	1,770.57	1,786.74	1,777.53
liquids	1,036.91	1,032.47	1,033.91	1,030.97	1,030.61	1,032.78	1,033.84	1,034.44	1,031.39	1,028.44	1,044.39	1,046.22	1,041.53	1,044.12	1,034.65	1,156.40	1,151.96	1,151.22	1,149.05	1,147.03
natural gas	152.47	158.71	157.65	166.94	163.18	136.00	140.12	140.18	146.00	143.37	180.36	184.84	183.01	194.25	187.01	172.16	177.27	175.86	185.15	181.63
electricity	386.65	392.12	391.36	398.45	396.09	368.01	371.51	372.27	375.68	374.08	416.91	420.84	419.85	428.68	423.29	430.75	436.99	435.94	445.06	441.40
coal	6.67	6.62	6.61	6.59	6.56	6.57	6.54	6.53	6.54	6.51	6.68	6.64	6.65	6.59	6.58	7.63	7.55	7.54	7.48	7.46
END-USE ENERGY CONSUMPTION (quadrillion Btu)	70.29	69.92	69.90	69.59	69.57	71.26	70.89	70.87	70.66	70.61	68.84	68.56	68.64	68.25	68.43	74.98	74.60	74.59	74.25	74.26
liquids	37.85	37.84	37.82	37.84	37.83	37.75	37.74	37.75	37.81	37.80	37.74	37.71	37.77	37.73	37.81	40.67	40.66	40.65	40.64	40.64
natural gas	16.26	15.95	15.94	15.69	15.66	17.32	16.97	16.93	16.66	16.58	15.13	14.92	14.92	14.71	14.73	17.13	16.83	16.81	16.58	16.53
electricity	14.59	14.55	14.56	14.48	14.52	14.61	14.62	14.62	14.61	14.66	14.39	14.35	14.38	14.25	14.32	15.43	15.39	15.41	15.31	15.37
coal	1.59	1.58	1.58	1.57	1.57	1.58	1.57	1.57	1.57	1.57	1.58	1.57	1.57	1.56	1.56	1.74	1.73	1.73	1.72	1.72
ELECTRIC GENERATION (billion kWh)	4,926.27	4,899.77	4,902.00	4,877.85	4,883.87	4,985.61	4,970.39	4,968.96	4,955.47	4,962.16	4,805.29	4,785.02	4,792.39	4,749.29	4,771.60	5,218.96	5,192.01	5,194.85	5,161.80	5,172.17
coal	2,142.71	2,177.86	2,173.08	2,205.23	2,199.91	1,965.65	2,017.08	2,010.40	2,076.04	2,072.01	2,250.96	2,299.95	2,288.43	2,318.37	2,307.93	2,230.53	2,234.24	2,247.81	2,248.95	2,243.60
gas	1,143.09	1,075.44	1,084.20	1,020.61	1,029.93	1,418.58	1,349.39	1,356.51	1,272.85	1,275.05	878.08	797.50	812.65	731.17	762.84	1,317.28	1,273.98	1,266.15	1,220.40	1,234.87
nuclear	876.67	876.67	876.67	876.67	876.67	858.29	858.29	858.29	858.29	863.83	876.67	878.22	878.27	879.99	878.26	876.67	877.25	876.67	877.38	876.67
renewables	702.87	707.59	705.79	711.29	713.75	681.48	683.24	681.93	685.54	688.71	734.07	743.56	747.72	752.68	756.76	730.61	742.46	740.48	748.18	750.94
other	60.93	62.21	62.25	64.05	63.60	61.62	62.40	61.82	62.74	62.56	65.51	65.81	65.32	67.09	65.81	63.87	64.07	63.73	66.89	66.09
PRIMARY ENERGY (quadrillion Btu)																				
Consumption	111.05	110.88	110.85	110.69	110.76	111.50	111.37	111.37	111.45	111.46	109.71	109.57	109.69	109.18	109.59	117.72	117.47	117.54	117.22	117.23
Imports	27.93	27.63	27.67	27.60	27.46	26.80	26.78	26.86	27.04	26.99	29.22	29.38	29.42	29.45	29.40	30.26	30.04	29.97	30.09	29.72
Exports	7.91	10.13	10.13	12.29	12.32	8.18	10.39	10.40	12.58	12.62	7.54	9.74	9.72	11.88	11.94	7.97	10.17	10.18	12.32	12.36
Production	90.96	93.37	93.26	95.38	95.65	92.89	95.05	94.99	97.21	97.27	87.86	89.79	89.86	91.50	92.04	95.31	97.52	97.67	99.38	99.80
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	6,114.82	6,136.49	6,131.49	6,155.61	6,152.88	6,074.00	6,103.94	6,102.31	6,151.52	6,146.61	6,084.64	6,103.94	6,106.49	6,104.89	6,120.61	6,521.09	6,517.76	6,525.31	6,521.52	6,520.16

Table B4. Differential from Base in U.S. Average Annual Values from 2025 to 2035 when Exports are Added

	Reference				High Shale EUR				Low Shale EUR				High Macroeconomic Growth			
	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																
Net Exports	2.18	2.19	4.23	4.28	2.06	2.05	4.09	4.10	1.88	1.76	3.93	3.85	2.17	2.17	4.09	4.26
gross imports	0.01	0.00	0.12	0.10	0.13	0.14	0.26	0.28	0.31	0.43	0.42	0.53	0.02	0.02	0.26	0.12
gross exports	2.19	2.19	4.35	4.38	2.19	2.19	4.35	4.38	2.19	2.19	4.35	4.38	2.19	2.19	4.35	4.38
Dry Production	1.51	1.59	3.00	3.15	1.43	1.49	2.77	2.78	1.24	1.25	2.62	2.90	1.74	1.71	3.15	3.47
shale gas	1.13	1.15	2.14	2.31	1.18	1.23	2.24	2.23	0.84	0.91	1.55	1.75	1.29	1.28	2.30	2.56
other	0.38	0.44	0.86	0.84	0.25	0.25	0.53	0.55	0.40	0.35	1.07	1.16	0.45	0.43	0.85	0.91
Delivered Volumes (1)	(0.75)	(0.67)	(1.36)	(1.26)	(0.69)	(0.63)	(1.43)	(1.43)	(0.72)	(0.59)	(1.44)	(1.13)	(0.51)	(0.54)	(1.08)	(0.95)
electric generators	(0.40)	(0.32)	(0.71)	(0.61)	(0.35)	(0.25)	(0.79)	(0.70)	(0.50)	(0.37)	(0.96)	(0.69)	(0.17)	(0.19)	(0.45)	(0.28)
industrial	(0.24)	(0.25)	(0.44)	(0.46)	(0.24)	(0.27)	(0.43)	(0.53)	(0.13)	(0.15)	(0.27)	(0.28)	(0.25)	(0.27)	(0.46)	(0.49)
residential	(0.04)	(0.04)	(0.08)	(0.08)	(0.03)	(0.03)	(0.07)	(0.06)	(0.03)	(0.03)	(0.08)	(0.06)	(0.04)	(0.03)	(0.07)	(0.07)
commercial	(0.06)	(0.06)	(0.12)	(0.11)	(0.05)	(0.06)	(0.11)	(0.10)	(0.05)	(0.04)	(0.11)	(0.08)	(0.05)	(0.04)	(0.10)	(0.09)
NATURAL GAS END-USE PRICES (2009$/Mcf)																
residential	0.55	0.48	1.15	0.95	0.35	0.37	0.79	0.67	0.46	0.33	1.27	0.78	0.43	0.35	0.97	0.81
commercial	0.54	0.48	1.12	0.92	0.33	0.34	0.73	0.61	0.47	0.34	1.29	0.78	0.41	0.34	0.93	0.76
industrial	0.62	0.54	1.44	1.16	0.46	0.48	1.07	0.92	0.49	0.36	1.39	0.78	0.55	0.46	1.32	1.09
OTHER PRICES																
Natural Gas Wellhead Price (2009$/Mcf)	0.54	0.47	1.27	1.01	0.36	0.38	0.86	0.71	0.52	0.43	1.44	0.85	0.45	0.38	1.15	0.90
Henry Hub Price (2009$/MMBtu)	0.60	0.52	1.39	1.11	0.40	0.41	0.95	0.79	0.57	0.47	1.59	0.94	0.50	0.42	1.26	1.00
Coal Minemouth Price (2009$/short-ton)	0.05	(0.03)	0.22	(0.03)	0.25	0.01	0.22	0.05	0.34	0.12	(0.01)	0.08	(0.29)	(0.35)	(0.30)	(0.14)
End-Use Electricity Price (2009 cents/KWh)	0.16	0.13	0.35	0.27	0.08	0.10	0.18	0.12	0.12	0.08	0.38	0.20	0.17	0.13	0.40	0.28
NATURAL GAS REVENUES (B 2009$)																
Export Revenues (2)	17.01	16.69	37.77	36.17	12.96	13.03	28.42	27.60	22.19	21.60	49.31	45.52	18.27	17.90	39.95	38.66
Domestic Supply Revenues (3)	22.53	21.50	50.21	44.94	16.11	16.89	35.77	31.78	21.14	19.48	54.05	43.89	23.68	21.37	51.70	47.99
production revenues (4)	23.23	21.93	53.09	46.98	17.31	17.97	39.36	34.84	21.67	19.88	55.41	44.23	24.28	21.81	54.56	49.85
delivery revenues (5)	(0.71)	(0.44)	(2.88)	(2.04)	(1.21)	(1.08)	(3.58)	(3.06)	(0.53)	(0.40)	(1.36)	(0.33)	(0.60)	(0.44)	(2.86)	(1.87)
Import Revenues (6)	1.82	1.59	4.91	4.02	1.95	2.06	4.35	4.11	3.63	3.43	7.32	5.87	1.79	1.56	5.39	4.03
END-USE ENERGY EXPENDITURES (B 2009$)	7.22	6.81	20.24	13.73	8.64	10.06	16.25	9.03	10.21	2.71	25.31	3.19	6.84	3.63	19.81	10.59
liquids	(4.45)	(3.01)	(5.94)	(6.31)	1.05	1.66	(1.39)	(4.34)	1.83	(2.86)	(0.27)	(9.74)	(4.43)	(5.17)	(7.34)	(9.37)
natural gas	6.25	5.18	14.47	10.71	4.12	4.18	10.00	7.37	4.49	2.65	13.90	6.65	5.12	3.70	12.99	9.47
electricity	5.47	4.71	11.80	9.44	3.50	4.26	7.68	6.07	3.94	2.94	11.78	6.39	6.24	5.19	14.31	10.65
coal	(0.05)	(0.07)	(0.08)	(0.11)	(0.03)	(0.04)	(0.03)	(0.06)	(0.04)	(0.03)	(0.09)	(0.11)	(0.08)	(0.09)	(0.15)	(0.16)
END-USE ENERGY CONSUMPTION (quadrillion Btu)	(0.37)	(0.38)	(0.70)	(0.71)	(0.37)	(0.39)	(0.60)	(0.65)	(0.28)	(0.20)	(0.60)	(0.42)	(0.38)	(0.39)	(0.73)	(0.72)
liquids	(0.00)	(0.02)	(0.01)	(0.02)	(0.01)	0.00	0.06	0.06	(0.03)	0.03	(0.01)	0.07	(0.02)	(0.03)	(0.03)	(0.03)
natural gas	(0.31)	(0.32)	(0.57)	(0.60)	(0.35)	(0.39)	(0.65)	(0.74)	(0.21)	(0.21)	(0.42)	(0.40)	(0.30)	(0.32)	(0.54)	(0.60)
electricity	(0.04)	(0.03)	(0.11)	(0.07)	0.00	0.01	(0.00)	0.04	(0.04)	(0.01)	(0.14)	(0.07)	(0.05)	(0.02)	(0.13)	(0.07)
coal	(0.01)	(0.01)	(0.02)	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.02)	(0.01)	(0.01)	(0.02)	(0.03)
ELECTRIC GENERATION (billion kWh)	(26.50)	(24.27)	(48.42)	(42.40)	(15.22)	(16.66)	(30.14)	(23.45)	(20.26)	(12.90)	(55.99)	(33.69)	(26.95)	(24.11)	(57.15)	(46.78)
coal	35.15	30.37	62.53	57.20	51.43	44.76	110.39	106.36	48.98	37.46	67.41	56.97	3.71	17.28	18.42	13.07
gas	(67.65)	(58.89)	(122.48)	(113.16)	(69.19)	(62.06)	(145.72)	(143.53)	(80.58)	(65.43)	(146.91)	(115.24)	(43.30)	(51.13)	(96.88)	(82.41)
nuclear	-	(0.00)	-	-	0.00	0.00	0.00	5.55	1.54	1.60	3.32	1.59	0.58	0.00	0.71	0.00
renewables	4.72	2.92	8.41	10.87	1.76	0.46	4.07	7.23	9.49	13.65	18.61	22.69	11.85	9.87	17.57	20.33
other	1.28	1.33	3.12	2.68	0.77	0.19	1.12	0.94	0.30	(0.19)	1.58	0.31	0.20	(0.13)	3.02	2.22
PRIMARY ENERGY (quadrillion Btu)																
Consumption	(0.16)	(0.20)	(0.35)	(0.29)	(0.13)	(0.13)	(0.05)	(0.04)	(0.13)	(0.02)	(0.53)	(0.12)	(0.25)	(0.18)	(0.50)	(0.49)
Imports	(0.30)	(0.26)	(0.33)	(0.47)	(0.03)	0.05	0.23	0.19	0.16	0.20	0.23	0.18	(0.22)	(0.30)	(0.17)	(0.54)
Exports	2.21	2.21	4.37	4.41	2.21	2.22	4.40	4.43	2.20	2.19	4.35	4.41	2.20	2.21	4.35	4.39
Production	2.41	2.30	4.42	4.69	2.16	2.10	4.32	4.38	1.93	2.00	3.65	4.18	2.20	2.36	4.07	4.49
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	21.67	16.67	40.79	38.07	29.94	28.31	77.52	72.61	19.31	21.85	20.25	35.98	(3.33)	4.21	0.43	(0.93)

Table B5. U.S. Annual Average Values from 2015 to 2035

	Reference					High Shale EUR					Low Shale EUR					High Macroeconomic Growth				
	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																				
Net Exports	(1.31)	0.57	0.78	1.81	2.63	(0.63)	1.21	1.41	2.44	3.24	(2.40)	(0.70)	(0.60)	0.52	1.21	(1.45)	0.44	0.64	1.60	2.49
gross imports	3.31	3.35	3.35	3.42	3.43	2.84	2.94	2.95	3.01	3.04	4.13	4.36	4.46	4.44	4.59	3.40	3.45	3.45	3.59	3.53
gross exports	2.00	3.93	4.13	5.23	6.06	2.22	4.15	4.35	5.45	6.28	1.73	3.66	3.86	4.96	5.79	1.95	3.88	4.09	5.19	6.02
Dry Production	24.18	25.37	25.52	26.24	26.78	27.48	28.71	28.86	29.52	29.95	20.40	21.47	21.51	22.28	22.86	25.37	26.75	26.83	27.60	28.26
shale gas	9.65	10.51	10.63	11.10	11.56	13.70	14.67	14.79	15.30	15.67	4.56	5.23	5.37	5.64	6.08	10.47	11.48	11.58	12.08	12.62
other	14.54	14.85	14.89	15.15	15.21	13.78	14.04	14.06	14.22	14.28	15.84	16.24	16.14	16.64	16.78	14.90	15.27	15.25	15.53	15.65
Delivered Volumes (1)	23.67	22.91	22.85	22.52	22.20	26.12	25.46	25.41	25.00	24.61	21.12	20.42	20.36	19.97	19.81	24.92	24.35	24.23	24.01	23.75
electric generators	7.06	6.58	6.57	6.36	6.18	8.64	8.26	8.28	7.98	7.77	5.44	4.97	4.98	4.69	4.66	7.63	7.36	7.29	7.18	7.09
industrial	8.10	7.92	7.88	7.81	7.72	8.62	8.42	8.38	8.31	8.18	7.60	7.46	7.42	7.38	7.29	8.59	8.39	8.34	8.27	8.16
residential	4.82	4.79	4.78	4.76	4.75	4.94	4.91	4.91	4.89	4.88	4.66	4.62	4.61	4.59	4.57	4.95	4.92	4.91	4.90	4.87
commercial	3.58	3.53	3.52	3.49	3.47	3.78	3.73	3.72	3.70	3.68	3.34	3.28	3.27	3.24	3.22	3.64	3.59	3.58	3.56	3.53
NATURAL GAS END-USE PRICES (2009$/Mcf)																				
residential	12.04	12.53	12.57	12.91	13.08	10.61	10.95	11.02	11.22	11.35	14.35	14.98	15.06	15.55	15.69	12.63	13.10	13.13	13.45	13.68
commercial	9.91	10.39	10.44	10.76	10.93	8.49	8.80	8.88	9.06	9.18	12.24	12.88	12.95	13.46	13.60	10.49	10.95	10.98	11.29	11.50
industrial	6.20	6.76	6.80	7.26	7.44	4.90	5.32	5.41	5.69	5.86	8.38	9.07	9.15	9.71	9.84	6.69	7.26	7.29	7.75	7.99
OTHER PRICES																				
Natural Gas Wellhead Price (2009$/Mcf)	5.28	5.78	5.82	6.23	6.39	4.01	4.35	4.42	4.66	4.79	7.37	8.06	8.16	8.71	8.87	5.75	6.25	6.28	6.69	6.90
Henry Hub Price (2009$/MMBtu)	5.81	6.36	6.41	6.86	7.03	4.41	4.79	4.87	5.12	5.27	8.12	8.88	8.98	9.60	9.77	6.33	6.88	6.91	7.36	7.60
Coal Minemouth Price (2009$/short-ton)	33.06	33.12	33.15	33.29	33.18	32.77	33.07	32.87	32.99	33.00	33.34	33.64	33.50	33.38	33.46	33.74	33.60	33.52	33.66	33.72
End-Use Electricity Price (2009 cents/KWh)	8.94	9.08	9.08	9.19	9.22	8.56	8.63	8.67	8.70	8.70	9.65	9.81	9.83	10.00	10.02	9.29	9.46	9.45	9.60	9.62
NATURAL GAS REVENUES (B 2009$)																				
Export Revenues (2)	11.13	25.11	26.34	37.49	43.23	8.98	19.64	20.80	28.85	33.39	15.07	34.12	35.85	50.80	58.30	12.11	27.19	28.43	40.19	46.69
Domestic Supply Revenues (3)	179.79	198.43	200.12	215.08	221.64	165.83	179.88	182.38	191.82	196.70	200.15	222.46	224.55	243.87	251.43	201.24	222.30	223.13	239.62	248.66
production revenues (4)	128.46	147.79	149.40	165.76	172.31	110.87	125.92	128.47	139.27	144.50	151.06	173.98	176.05	196.01	203.32	147.54	169.19	169.97	187.82	196.82
delivery revenues (5)	51.32	50.64	50.72	49.32	49.33	54.96	53.96	53.92	52.55	52.21	49.09	48.48	48.50	47.86	48.12	53.70	53.12	53.16	51.79	51.84
Import Revenues (6)	17.77	19.53	19.69	21.37	22.03	11.92	13.52	13.84	14.94	15.61	30.84	34.49	35.15	37.10	38.16	19.97	21.90	22.09	24.07	24.58
END-USE ENERGY EXPENDITURES (B 2009$)	1,489.93	1,499.04	1,499.79	1,507.51	1,510.31	1,455.15	1,463.17	1,465.18	1,469.08	1,469.35	1,547.09	1,561.08	1,559.57	1,572.52	1,567.30	1,625.45	1,635.66	1,634.71	1,644.67	1,646.03
liquids	974.71	973.09	973.49	972.64	972.64	970.30	971.23	971.23	970.91	969.68	981.60	983.31	980.57	982.05	975.74	1,063.35	1,061.47	1,060.75	1,060.30	1,058.97
natural gas	140.16	146.09	146.41	151.27	152.79	124.61	128.76	129.62	132.45	133.62	165.55	172.70	173.21	179.55	180.30	154.27	160.27	160.24	165.41	167.51
electricity	368.28	373.10	373.13	376.85	378.14	353.56	356.51	357.67	359.05	359.38	393.11	398.26	398.98	404.14	404.50	400.29	406.41	406.21	411.48	412.09
coal	6.78	6.76	6.75	6.75	6.74	6.68	6.68	6.67	6.68	6.67	6.83	6.81	6.81	6.78	6.76	7.54	7.51	7.50	7.48	7.46
END-USE ENERGY CONSUMPTION (quadrillion Btu)	69.09	68.81	68.75	68.64	68.49	69.93	69.65	69.59	69.52	69.37	67.90	67.61	67.58	67.42	67.33	72.62	72.33	72.26	72.14	71.97
liquids	37.29	37.30	37.29	37.31	37.31	37.21	37.23	37.24	37.28	37.28	37.24	37.23	37.25	37.25	37.28	39.42	39.43	39.42	39.43	39.44
natural gas	16.15	15.90	15.85	15.76	15.61	17.04	16.76	16.69	16.58	16.41	15.18	14.95	14.89	14.82	14.69	16.81	16.55	16.49	16.41	16.23
electricity	14.02	13.98	13.98	13.95	13.95	14.05	14.05	14.04	14.04	14.06	13.85	13.81	13.81	13.74	13.74	14.64	14.60	14.61	14.55	14.56
coal	1.63	1.63	1.63	1.63	1.62	1.62	1.62	1.62	1.62	1.62	1.63	1.62	1.62	1.62	1.61	1.76	1.75	1.75	1.74	1.74
ELECTRIC GENERATION (billion kWh)	4,691.78	4,671.70	4,670.36	4,660.47	4,654.31	4,740.10	4,728.42	4,724.32	4,720.03	4,717.90	4,599.04	4,578.46	4,576.69	4,554.90	4,551.26	4,907.86	4,886.10	4,884.89	4,868.85	4,864.09
coal	2,030.24	2,078.96	2,083.33	2,100.15	2,121.75	1,860.54	1,912.06	1,912.09	1,949.35	1,977.66	2,171.63	2,216.91	2,212.07	2,221.68	2,224.94	2,114.85	2,134.13	2,149.63	2,144.11	2,158.39
gas	1,074.40	1,000.10	995.54	963.40	932.18	1,328.06	1,262.83	1,259.57	1,215.21	1,175.80	808.02	735.39	733.01	695.09	685.68	1,181.25	1,129.59	1,115.49	1,096.96	1,074.83
nuclear	871.23	871.23	871.23	871.23	871.23	854.18	854.18	854.18	854.53	859.21	871.23	872.04	872.07	872.97	872.07	871.23	871.54	871.23	871.61	871.23
renewables	655.74	660.26	658.89	663.43	666.81	636.24	637.87	637.72	639.17	643.29	684.94	690.77	696.38	700.70	704.42	678.14	688.13	686.04	691.94	695.77
other	60.17	61.15	61.37	62.26	62.34	61.08	61.49	60.76	61.77	61.93	63.21	63.35	63.16	64.47	64.16	62.38	62.71	62.50	64.24	63.86
PRIMARY ENERGY (quadrillion Btu)																				
Consumption	107.97	107.90	107.87	107.85	107.85	108.38	108.31	108.27	108.38	108.37	107.04	106.89	106.89	106.66	106.70	113.05	112.91	112.92	112.81	112.71
Imports	28.28	28.20	28.21	28.18	28.19	27.27	27.28	27.34	27.47	27.49	29.50	29.62	29.68	29.71	29.75	30.17	30.14	30.09	30.17	30.02
Exports	7.48	9.43	9.63	10.73	11.57	7.69	9.64	9.86	10.96	11.81	7.19	9.12	9.32	10.41	11.25	7.53	9.47	9.68	10.77	11.61
Production	87.04	89.04	89.18	90.30	91.17	88.73	90.66	90.77	91.94	92.73	84.52	86.20	86.35	87.18	88.04	90.24	92.09	92.35	93.26	94.16
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	5,955.05	5,985.66	5,986.04	6,001.82	6,013.46	5,915.71	5,947.04	5,946.80	5,977.68	5,991.27	5,960.10	5,981.23	5,978.85	5,976.06	5,984.27	6,270.24	6,279.14	6,286.47	6,283.68	6,290.23

Table B6. Differential from Base in U.S. Average Annual Values from 2015 to 2035 when Exports are Added

	Reference				High Shale EUR				Low Shale EUR				High Macroeconomic Growth			
	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																
Net Exports	1.89	2.10	3.12	3.95	1.84	2.03	3.06	3.87	1.70	1.81	2.92	3.61	1.89	2.09	3.05	3.94
gross imports	0.04	0.04	0.11	0.12	0.09	0.10	0.17	0.20	0.23	0.33	0.31	0.46	0.04	0.05	0.19	0.13
gross exports	1.93	2.14	3.23	4.07	1.93	2.14	3.23	4.07	1.93	2.14	3.23	4.07	1.93	2.14	3.23	4.07
Dry Production	1.18	1.33	2.06	2.59	1.23	1.38	2.04	2.47	1.06	1.11	1.88	2.45	1.38	1.46	2.23	2.89
shale gas	0.86	0.98	1.45	1.91	0.97	1.09	1.60	1.97	0.67	0.81	1.08	1.52	1.01	1.11	1.61	2.15
other	0.32	0.35	0.61	0.68	0.26	0.28	0.44	0.50	0.40	0.30	0.80	0.93	0.37	0.35	0.62	0.74
Delivered Volumes (1)	(0.76)	(0.82)	(1.15)	(1.47)	(0.66)	(0.71)	(1.12)	(1.51)	(0.71)	(0.77)	(1.15)	(1.31)	(0.57)	(0.69)	(0.91)	(1.17)
electric generators	(0.48)	(0.49)	(0.70)	(0.88)	(0.38)	(0.36)	(0.66)	(0.87)	(0.46)	(0.46)	(0.75)	(0.78)	(0.27)	(0.34)	(0.45)	(0.54)
industrial	(0.18)	(0.22)	(0.29)	(0.38)	(0.19)	(0.24)	(0.31)	(0.44)	(0.14)	(0.19)	(0.22)	(0.32)	(0.20)	(0.25)	(0.32)	(0.43)
residential	(0.04)	(0.04)	(0.06)	(0.08)	(0.03)	(0.04)	(0.05)	(0.06)	(0.04)	(0.05)	(0.07)	(0.09)	(0.04)	(0.04)	(0.06)	(0.08)
commercial	(0.05)	(0.06)	(0.09)	(0.11)	(0.05)	(0.06)	(0.08)	(0.10)	(0.06)	(0.07)	(0.10)	(0.12)	(0.05)	(0.06)	(0.08)	(0.11)
NATURAL GAS END-USE PRICES (2009$/Mcf)																
residential	0.49	0.53	0.87	1.04	0.33	0.41	0.60	0.73	0.64	0.71	1.20	1.34	0.47	0.50	0.82	1.05
commercial	0.48	0.52	0.84	1.02	0.31	0.39	0.57	0.69	0.64	0.71	1.22	1.35	0.46	0.49	0.80	1.02
industrial	0.56	0.60	1.07	1.24	0.42	0.51	0.79	0.96	0.69	0.77	1.33	1.46	0.57	0.60	1.06	1.30
OTHER PRICES																
Natural Gas Wellhead Price (2009$/Mcf)	0.50	0.54	0.95	1.11	0.34	0.42	0.65	0.79	0.69	0.79	1.34	1.50	0.50	0.52	0.94	1.15
Henry Hub Price (2009$/MMBtu)	0.55	0.59	1.05	1.22	0.38	0.46	0.72	0.87	0.77	0.87	1.48	1.65	0.55	0.58	1.03	1.26
Coal Minemouth Price (2009$/short-ton)	0.06	0.09	0.22	0.12	0.30	0.11	0.22	0.24	0.29	0.16	0.04	0.12	(0.14)	(0.22)	(0.08)	(0.02)
End-Use Electricity Price (2009 cents/KWh)	0.14	0.14	0.25	0.29	0.07	0.10	0.13	0.13	0.16	0.18	0.35	0.37	0.17	0.16	0.31	0.33
NATURAL GAS REVENUES (B 2009$)																
Export Revenues (2)	13.99	15.22	26.36	32.10	10.66	11.82	19.87	24.41	19.05	20.78	35.73	43.23	15.08	16.32	28.08	34.57
Domestic Supply Revenues (3)	18.64	20.34	35.29	41.85	14.05	16.55	25.99	30.88	22.30	24.39	43.72	51.28	21.06	21.88	38.37	47.42
production revenues (4)	19.33	20.94	37.29	43.84	15.05	17.60	28.40	33.63	22.92	24.98	44.95	52.25	21.64	22.43	40.28	49.28
delivery revenues (5)	(0.69)	(0.60)	(2.00)	(1.99)	(1.00)	(1.04)	(2.41)	(2.75)	(0.61)	(0.59)	(1.23)	(0.97)	(0.58)	(0.54)	(1.91)	(1.86)
Import Revenues (6)	1.76	1.93	3.60	4.26	1.60	1.92	3.02	3.69	3.65	4.31	6.26	7.31	1.93	2.12	4.11	4.61
END-USE ENERGY EXPENDITURES (B 2009$)	9.11	9.86	17.59	20.39	8.02	10.03	13.93	14.19	13.98	12.47	25.42	20.21	10.22	9.26	19.22	20.58
liquids	(1.63)	(1.22)	(2.07)	(2.07)	0.92	0.92	0.61	(0.62)	1.70	(1.04)	0.45	(5.86)	(1.88)	(2.60)	(3.05)	(4.38)
natural gas	5.94	6.26	11.12	12.63	4.15	5.01	7.84	9.01	7.15	7.66	14.00	14.75	6.00	5.98	11.14	13.24
electricity	4.82	4.86	8.57	9.87	2.95	4.11	5.49	5.82	5.15	5.87	11.03	11.39	6.12	5.92	11.19	11.80
coal	(0.02)	(0.03)	(0.03)	(0.04)	(0.01)	(0.02)	(0.00)	(0.02)	(0.02)	(0.02)	(0.05)	(0.07)	(0.03)	(0.04)	(0.06)	(0.08)
END-USE ENERGY CONSUMPTION (quadrillion Btu)	(0.28)	(0.34)	(0.45)	(0.60)	(0.27)	(0.34)	(0.41)	(0.55)	(0.29)	(0.32)	(0.48)	(0.57)	(0.30)	(0.36)	(0.49)	(0.65)
liquids	0.01	0.00	0.03	0.03	0.02	0.02	0.06	0.07	(0.01)	0.02	0.01	0.04	0.02	0.00	0.02	0.02
natural gas	(0.25)	(0.30)	(0.40)	(0.54)	(0.28)	(0.35)	(0.46)	(0.63)	(0.23)	(0.29)	(0.36)	(0.49)	(0.27)	(0.33)	(0.41)	(0.58)
electricity	(0.04)	(0.03)	(0.07)	(0.07)	(0.00)	(0.00)	(0.00)	0.02	(0.05)	(0.05)	(0.11)	(0.11)	(0.04)	(0.03)	(0.09)	(0.08)
coal	(0.00)	(0.01)	(0.01)	(0.01)	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)	(0.01)	(0.01)	(0.02)
ELECTRIC GENERATION (billion kWh)	(20.08)	(21.43)	(31.31)	(37.47)	(11.67)	(15.77)	(20.07)	(22.20)	(20.58)	(22.35)	(44.13)	(47.78)	(21.76)	(22.98)	(39.01)	(43.78)
coal	48.72	53.09	69.91	91.51	51.52	51.55	88.82	117.12	45.28	40.44	50.04	53.31	19.28	34.78	29.25	43.53
gas	(74.30)	(78.86)	(111.00)	(142.22)	(65.24)	(68.49)	(112.86)	(152.26)	(72.63)	(75.01)	(112.93)	(122.34)	(51.66)	(65.76)	(84.29)	(106.42)
nuclear	-	(0.00)	-	-	0.00	0.00	0.35	5.02	0.81	0.84	1.74	0.83	0.30	0.00	0.37	0.00
renewables	4.52	3.15	7.69	11.07	1.63	1.48	2.94	7.06	5.84	11.44	15.76	19.48	9.99	7.89	13.80	17.63
other	0.98	1.20	2.09	2.17	0.41	(0.32)	0.69	0.86	0.13	(0.06)	1.25	0.94	0.33	0.11	1.86	1.48
PRIMARY ENERGY (quadrillion Btu)																
Consumption	(0.07)	(0.10)	(0.12)	(0.12)	(0.06)	(0.11)	0.01	(0.00)	(0.15)	(0.15)	(0.38)	(0.34)	(0.13)	(0.13)	(0.24)	(0.34)
Imports	(0.09)	(0.08)	(0.10)	(0.10)	0.01	0.07	0.20	0.22	0.12	0.18	0.21	0.25	(0.03)	(0.07)	0.00	(0.15)
Exports	1.94	2.15	3.25	4.09	1.96	2.17	3.28	4.12	1.93	2.13	3.22	4.06	1.94	2.15	3.24	4.08
Production	2.00	2.14	3.26	4.13	1.93	2.03	3.20	4.00	1.68	1.83	2.66	3.52	1.85	2.11	3.02	3.92
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	30.62	30.99	46.77	58.42	31.33	31.09	61.96	75.56	21.14	18.75	15.96	24.18	8.90	16.23	13.44	19.99

FOOTNOTES

(1) total includes components below plus deliveries to the transportation sector

(2) export volumes added for this study times the Henry Hub price plus an assumed transport fee to the liquefaction facility of 20 cents per Mcf, plus sum of all other export volumes (i.e., to Canada and Mexico) times the associated price at the border

(3) represents producer revenues at the wellhead plus other revenues extracted before final gas delivery.

(4) dry gas production times average wellhead or first-purchase price

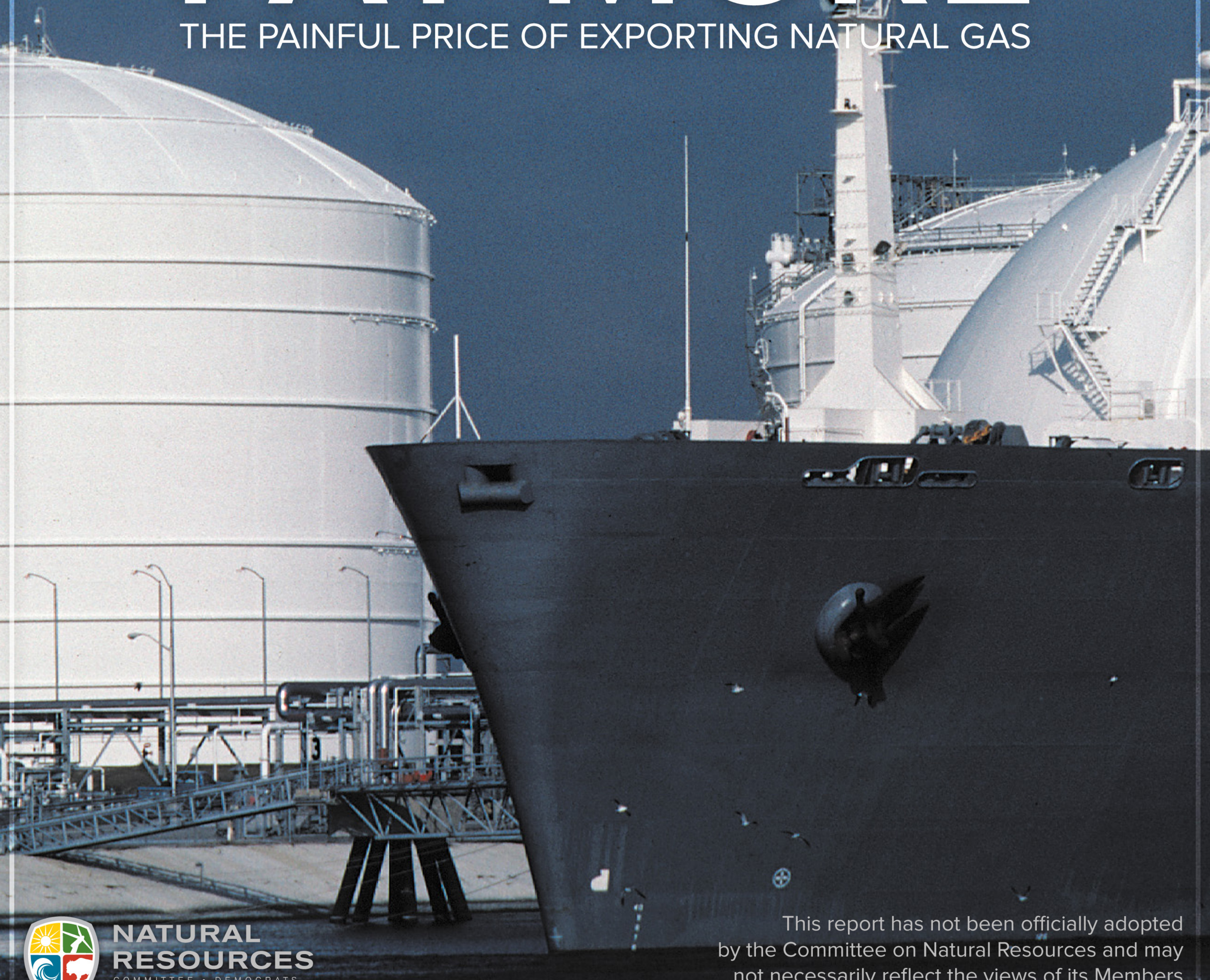
(5) represented revenues extracted as gas moves from the first-purchase wellhead price to final delivery

(6) import volumes times the associated price at the border

Projections: EIA, Annual Energy Outlook 2011 National Energy Modeling system runs ref2011.d020911a, rflexslw.d090911a, rflexrpd.d090911a, rfhexslw.d090911a, rfhesrpd.d090911a, hshleur.d020911a, helexslw.d090911a, helexrpd.d090911a, hehexslw.d090911a, hehexrpd.d090911a, feleur.d090811a, lelexslw.d090911a, lelexrpd.d090911a, lehexslw.d090911a, lehexrpd.d090911a, fehdem.d090811a, hmlexslw.d090911a, hmlexrpd.d090911a, hmhexslw.d090911a, hmhexrpd.d090911a

DRILL HERE SELL THERE PAY MORE

THE PAINFUL PRICE OF EXPORTING NATURAL GAS



NATURAL RESOURCES
COMMITTEE • DEMOCRATS

This report has not been officially adopted by the Committee on Natural Resources and may not necessarily reflect the views of its Members

Executive Summary

The United States faces a critical decision about whether to export natural gas following the rapid expansion of domestic production in recent years. The Department of Energy has already approved one export application and is currently considering eight others. If these applications are approved and the companies export at full capacity, the United States could soon be exporting more than 20 percent of current consumption. The Energy Information Administration has estimated that exporting even less natural gas than what is currently under consideration could raise domestic prices 24 to 54 percent, which would substantially increase energy bills for American consumers and could potentially have catastrophic impacts on U.S. manufacturing.

In a February 24th letter to Massachusetts Congressman Edward J. Markey, Department of Energy (DOE) official Christopher Smith made clear that no additional export permits will be approved by the Department at least until an additional evaluation of the macroeconomic impact of these prospective exports is completed and reviewed by DOE this spring.[1] This decision represents an important deliberative step that ensures deeper consideration will be given to the ramifications of energy exporting.

In examining energy markets and the impacts of higher natural gas prices, the House Natural Resources Democratic Staff found that:

- Unlike the oil market, natural gas prices are not determined on a global market. Natural gas prices in Europe and Asia are 3 to 7 times higher than in the United States. This provides the American economy with a competitive advantage in the manufacture of energy-intensive goods.

- From 2000 to 2008, the price of natural gas rose more than 400 percent, and was a major contributor to the U.S. manufacturing sector losing 3.7 million jobs. While larger macroeconomic forces were also at work during this period, it is clear that the cost of natural gas for industries like steel, plastics, chemicals, paper, glass, fertilizer, cement, and refining is a very significant determinant in whether facilities are sited domestically or overseas. Keeping American natural gas resources in America and keeping prices low will support a more diversified domestic economy and provide greater domestic job benefits than pursuing an export strategy.

- Keeping natural gas resources at home will allow greater amounts of natural gas to be used in the domestic electric power and transportation sectors. Greater natural gas utilization in these sectors could lead directly to a 1.2 million barrel per day reduction in

[1] Included as an appendix to this report.

foreign oil imports and a 9 percent reduction in coal consumption by 2035, which would measurably enhance America's national, economic, and environmental security.

Legislation introduced by Rep. Markey would prevent companies from exporting natural gas extracted from public lands (H.R. 4025) and would place a moratorium on the Federal Energy Regulatory Commission approving the siting and development of LNG export terminals before 2025, except under special circumstances (H.R. 4024).

Background

On June 10, 2003, the Chairman of the Federal Reserve Board, Alan Greenspan, testified before the House Energy and Commerce Committee that rising natural gas prices were harming domestic manufacturers and that large numbers of liquefied natural gas (LNG) terminals were needed to import more natural gas and stabilize prices. He said:

> *The updrift and volatility of the spot price for gas have put significant segments of the North American gas-using industry in a weakened competitive position. …The perceived tightening of long-term demand-supply balances is beginning to price some industrial demand out of the market. …Access to world natural gas supplies will require a major expansion of LNG terminal import capacity. …As the technology of LNG liquefaction and shipping has improved, and as safety considerations have lessened, a major expansion of U.S. import capability appears to be under way. These movements bode well for widespread natural gas availability in North America in the years ahead.*[2]

Chairman Greenspan was half right. Since natural gas is both the primary fuel source for the industrial sector and a primary feedstock for the production of plastics, chemicals, fertilizers, and many other products, low-price natural gas is essential to our industrial competitiveness. The increase in natural gas prices of more than 400 percent between 2000 and 2008 significantly undermined American industrial competitiveness and was a major factor in the loss of 3.7 million manufacturing jobs during that time.[3]

But Chairman Greenspan turned out to be wrong about our need to import large amounts of LNG. Subsequent discoveries of domestic shale gas deposits and advances in horizontal drilling and hydraulic fracturing techniques, have led to expanded domestic gas reserves and production and the lowest well-head prices[4] in 10 years. Of the nearly 50 LNG import terminals that have been certified for construction,[5] only 12 facilities were ultimately built.[6] And of this 6.95 trillion cubic feet (Tcf) of LNG import capacity, only 0.35 Tcf of natural gas was actually

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[2] Testimony of Alan Greenspan, Chairman, Federal Reserve, before the House Committee on Energy and Commerce, June 10, 2003, available at http://www.federalreserve.gov/boarddocs/testimony/2003/20030610/default.htm

[3] Testimony of Rich Wells, Vice President Energy, The Dow Chemical Company, before the House Select Committee on Energy Independence and Global Warming, July 30, 2008, available at http://globalwarming.house.gov/files/HRG/FullTranscripts/110-46_2008-07-30.pdf

[4] The well-head price is the price charged by the producer for petroleum or natural gas without transportation costs. See http://www.merriam-webster.com/dictionary/wellhead+price#

[5] Testimony of Kenneth B. Medlock III, Rice University, before the Senate Committee on Energy and Natural Resources, Nov. 8, 2011, available at http://energy.senate.gov/public/_files/MedlockTestimony110811.pdf.

[6] Federal Energy Regulatory Commission, North American LNG Import Terminals – Existing, January 10, 2012, available at http://ferc.gov/industries/gas/indus-act/lng/LNG-existing.pdf

imported in 2011, a utilization rate of 5 percent.[7] Several of these import terminals are now mothballed entirely and their owners are looking to turn them into LNG export terminals. [8]

The Natural Gas Market Today

Natural gas production in the United States reached a historical high in November 2011, when producers withdrew an average of 82.7 billion cubic feet per day, 18 percent higher than five years earlier.[9] This expansion in domestic natural gas supplies has led to a reduction in domestic prices. Even while consumption of natural gas has been increasing, the average wellhead price has stayed below $5 per million cubic feet (Mcf) for more than two years. Shale gas now accounts for more than a third of total U.S. gas resources.[10] The Energy Information Administration (EIA) estimates that shale gas will provide 49 percent of total U.S. natural gas supply by 2035, up from 23 percent in 2010.[11] Net imports now represent 10 percent of total U.S. consumption, the lowest proportion since 1993, and this share is expected to continue to shrink.

Unlike oil, natural gas prices are not set on a global market. Natural gas cannot currently be moved cheaply in volumes great enough to efficiently link low-cost producing regions with high-demand regions. With massive deployment of expensive infrastructure—international natural gas pipelines, special cryogenic LNG tankers, liquefaction equipment—regional natural prices would converge to a global price in the same way that global oil prices have emerged. However, like the oil market, a global natural gas market could be manipulated by nations, national companies, and cartels in the same way that the Organization of Petroleum Exporting Countries (OPEC) now manipulates the global oil market.

Regional variation in natural gas prices is considerable, as seen in Figure 1. For example, natural gas prices are six to seven times higher in Asia than they are in the United States. Prices are more than three times higher throughout most of Europe. The regional nature of the natural gas market clearly benefits American consumers and businesses.

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[7] Federal Energy Regulatory Commission, North American LNG Import Terminals – Existing, January 10, 2012, available at http://ferc.gov/industries/gas/indus-act/lng/LNG-existing.pdf; Energy Information Administration, *U.S. Natural Gas Imports by Country,* available at http://www.eia.gov/dnav/ng/ng_move_impc_s1_a.htm

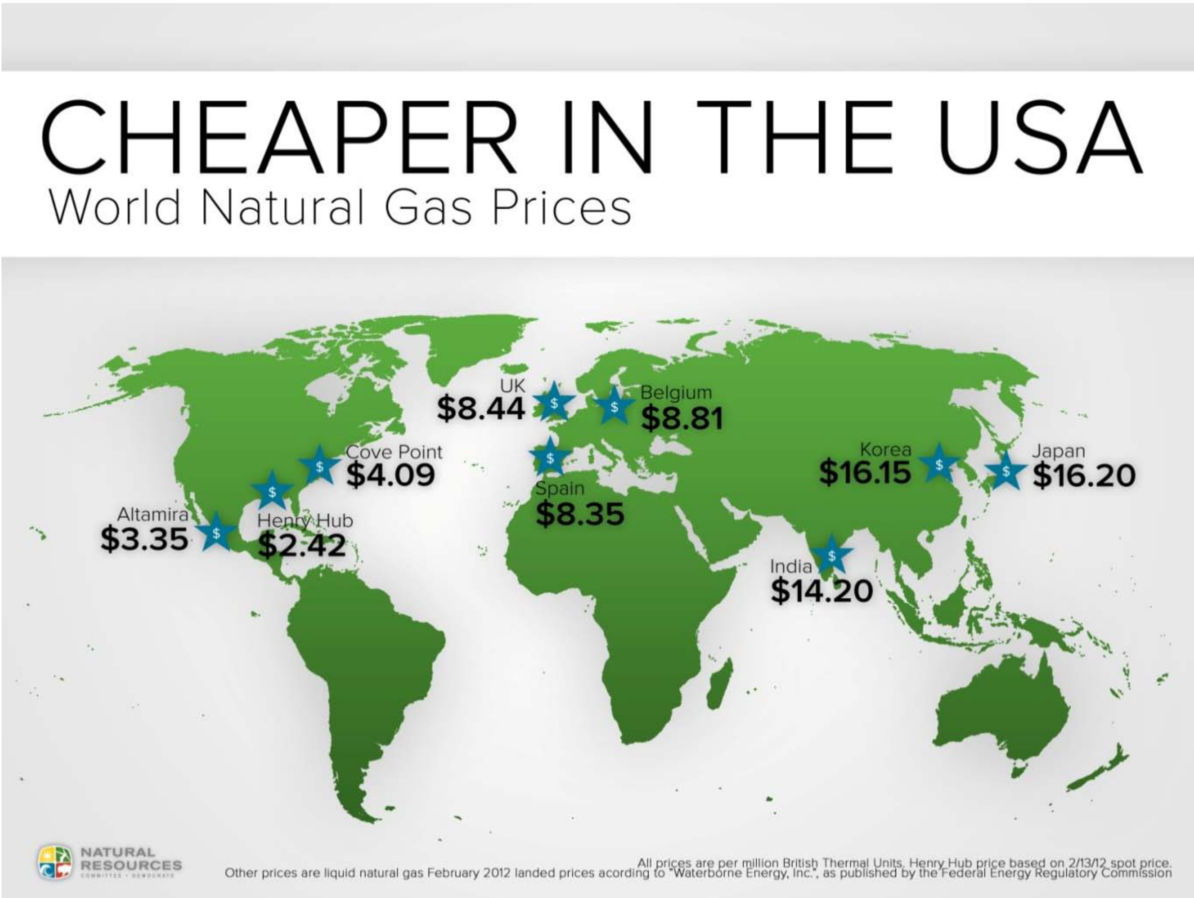
[8] Energy Information Administration, *U.S. Natural Gas Imports by Point of Entry*, available at http://www.eia.gov/dnav/ng/ng_move_poe1_a_EPG0_IML_Mmcf_a.htm

[9] Energy Information Administration, *Monthly Natural Gas Gross Production Report,* February, 2012, available at *http://www.eia.gov/oil_gas/natural_gas/data_publications/eia914/eia914.html*

[10] U.S. Geological Survey, *Total Oil and Gas Resources*, available at http://certmapper.cr.usgs.gov/data/noga00/natl/tabular/2011/2011_FINAL_TABLE.xls

[11] Energy Information Administration, *Annual Energy Outlook 2012*, available at *http://www.eia.doe.gov/oiaf/aeo/*

Figure 1. Natural Gas Prices around the World

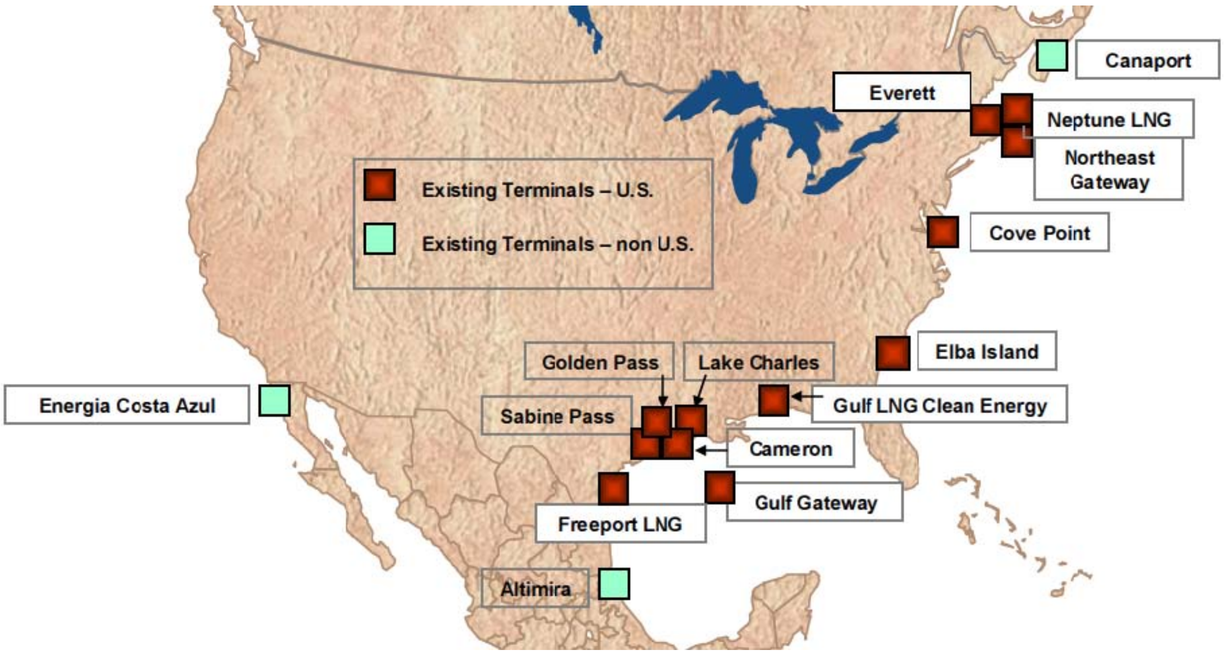


<u>The Department of Energy Considers Export Permits</u>

Export Applications Pour In

As a result of high domestic natural gas production and higher prices in foreign markets, several companies have submitted applications to the Department of Energy over the past year seeking permits to export domestically produced natural gas. Most of these applications are planning to use LNG terminals that were originally built for importing. Existing terminals can be seen in Figure 2.

Figure 2. Existing North American LNG Terminals



Source: U.S. Department of Energy. Available at:
http://fossil.energy.gov/programs/oilgas/storage/publications/Complete_LNG_Terminal_Status_Maps_Q2_201.pdf

DOE has already approved a plan from a Cheniere Energy subsidiary, Sabine Pass Liquefaction, to export LNG through a terminal originally built for importing the fuel. This export facility, which is still at least four years away from becoming operational, has booked major deals to export American natural gas to Indian and Korean markets and, in total, has long-term agreements in place to export 89 percent of its approved capacity.[12] DOE is now considering eight other LNG export applications. If all nine export applications are approved and this export capacity is fully utilized, the companies would export an amount equal to 20.6 percent of current U.S. consumption, according to data provided by DOE to Democratic staff on the House Natural Resources Committee.

After the Sabine Pass approval in May of 2011 and the subsequent rush of new applicants, DOE commissioned the EIA and a private contractor to undertake separate studies on the cumulative impacts of pending natural gas export applications. DOE has since committed to withhold approval of the pending export applications until these studies are completed. EIA released its study in January, finding that domestic natural gas prices could rise more than 50 percent if exports take off (see summary below). The second study is scheduled to be completed this spring.

[12] Edward Klump, *Korea Gas to Buy U.S. LNG as Gas Slump Attracts Asian Importers*, available at http://www.bloomberg.com/news/2012-01-30/cheniere-agrees-to-sabine-pass-export-deal-with-korea-gas-1-.html

Roles and Authorities

Section 3(a) of the Natural Gas Act of 1938 defines the process for DOE's reviews of most LNG export applications. In particular, the Secretary of Energy must approve an export application "unless after opportunity for hearing, [the Secretary] finds that the proposed exportation… will not be consistent with the public interest." Thus, there is "a rebuttable presumption that a proposed export of natural gas is in the public interest," according to DOE. This presumption must be overcome for DOE to deny an export application. For export approvals, DOE may also attach terms or conditions that it considers necessary to protect the public interest.

The Energy Policy Act of 1992 amended the Natural Gas Act to further limit DOE's ability to deny natural gas export applications. Specifically, DOE *must* approve applications to export natural gas to the 15 countries that have free trade agreements (FTAs) with the United States covering natural gas.[13] Such applications are automatically deemed in the public interest, and DOE cannot add any terms or conditions to approvals.

In addition to DOE authorization to export LNG, companies must receive authorization from the Federal Energy Regulatory Commission (FERC) for the actual siting and development of LNG projects, as specified under Section 3 of the Natural Gas Act.[14] FERC is also the lead agency responsible for the preparation of the analysis and decisions required under National Environmental Policy Act for the approval of new facilities, including tanker operation, marine facilities, and terminal construction and operation, environmental and cultural impacts.[15]

The Energy Information Administration Study

If DOE approves the pending applications and exports rise as expected, domestic natural gas prices could increase 24 to 54 percent, depending on recoverable shale resources and how quickly exports are ramped up, according to the EIA's January report.[16] About three-quarters of the increased natural gas production needed to satisfy such export demand would come from shale sources, according to an EIA export scenario. That would require a dramatic expansion of hydraulic fracturing, or "fracking," which is necessary to access these resources.

Higher prices are also expected to substantially reduce U.S. demand for natural gas. Around 30 to 40 percent of natural gas export demand would be met through reduced domestic consumption, not increased production, according to EIA. Consequently, EIA projects that dirty

[13] These countries are Australia, Bahrain, Canada, Chile, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Peru, and Singapore. Three other countries, South Korea, Colombia, and Panama, will soon join this club when their Senate-ratified trade agreements take effect.
[14] 15 U.S.C. § 717
[15] Interagency Agreement Among the FERC et al. Available at: www.ferc.gov/legal/maj-ord-reg/mou/mou-24.pdf
[16] Energy Information Administration, *Effect of Increase Natural Gas Exports on Domestic Energy Markets*, available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf

coal-fired power generation will rise in the United States to make up for the expected decline in natural gas-fired electricity generation.

Energy Department Responds to Markey Letter

Rep. Markey, Ranking Member on the House Natural Resources Committee, wrote to Energy Secretary Steven Chu in January asking about the consequences of exporting greater amounts of natural gas, including the consequences for prices, manufacturing and economic growth, energy security, and the environment.

Deputy Assistant Secretary Christopher Smith responded on behalf of Secretary Chu. This response, delivered February 24th, noted that DOE has already approved the export of 10.93 billion cubic feet of natural gas per day (Bcf/d) to countries with free trade agreements with the United States.[17] The EIA report looked at export scenarios associated with the approval of additional exports to counties without free trade agreements. The second report by the private contractor is still being completed, but Smith wrote that it would provide important information about the macroeconomic consequences resulting from EIA's export scenarios, including:

- Consequences for domestic energy consumption, production, and prices;
- Effects on gross domestic product, job creation, and balance of trade; and
- Impacts on U.S. manufacturers, especially energy intensive industries.

Smith made clear that DOE would not approve the pending export applications until this study is finished and DOE has considered the findings. "We are mindful of the need for prompt action in each of the non-FTA LNG export proceedings before us," Smith wrote. "We are equally mindful that a sound evidentiary record is essential to reach a reasoned decision in these proceedings. As such, DOE will not issue a final order addressing the pending applications to export LNG to non-FTA countries until the full study has been completed and the Department has had an opportunity to review the results."

Economic Ramifications of Exporting

The United States currently enjoys affordable natural gas that benefits consumers and also provides us with a competitive advantage that is felt up and down the U.S. economy. Affordable natural gas keeps energy prices low for consumers that rely on natural gas for heating, cooking, and electricity. Increasing those energy costs on American consumers and businesses by exporting would have a direct impact on their disposable income and reduce their purchasing power.

Industrial and manufacturing facilities are the largest consumers of natural gas in the United States—ahead of the electricity, commercial, and residential sectors—and would be especially hard hit. These facilities may require natural gas not only as a primary energy source

[17] DOE now has pending or approved permits for exports to FTA countries totaling 12.51 Bfc/d. DOE LNG docket available at: http://fossil.energy.gov/programs/gasregulation/LNG_Summary_Table_2-29-12_2.pdf

but also use it as a physical input into product. In some sectors, like fertilizers and chemicals, natural gas can constitute 80 to 90 percent of the cost of production. For businesses like these, the cost of energy may be the number one determining factor in whether to site production in the United States and employ American workers or whether to move production overseas.

In the past, high natural gas prices have had a disastrous effect on U.S. manufacturing. From 2000 to 2008, the price of natural gas rose more than 400 percent, and was a major contributor to the U.S. manufacturing sector losing 3.7 million jobs.[18] Other variables were certainly relevant to this undermining of manufacturing competitiveness as well, including the 2001 recession in the global trend of moving manufacturing to countries with lower labor costs. However, for energy intensive industries—like aluminum, steel, plastics, chemicals, paper, glass, fertilizer, food processing, cement, and refining—the cost of energy is a far greater share of production costs than labor and a more significant determinant in facility siting.

The experiences of some specific energy-intensive industries below illustrate the dangers that natural gas exporting could have on sectors of the U.S. economy.

Fertilizer Industry

An important use of natural gas is as a feedstock in fertilizer production. In this process, natural gas is used to produce ammonia, which has a high nitrogen content, and the ammonia becomes the primary component of nitrogen fertilizers. It takes 33,500 cubic feet of natural gas to manufacture 1 ton of anhydrous ammonia fertilizer.[19] As a result, natural gas can account for up to 90 percent of the cost to produce ammonia fertilizer.[20]

The fertilizer sector is the largest industrial consumer of natural gas in the United States, consuming 60 percent of U.S. industrial demand.[21] The period between 2000 and 2006 was a devastating one for the U.S. fertilizer industry, as seen in Figure 3. Domestic ammonia fertilizer production declined 44 percent, and more than a third of all U.S. fertilizer production capacity shuttered. At the same time, imports skyrocketed 115 percent.[22]

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[18] Dow Jones Industrial Average Basic Chart, Yahoo! Finance, available at http://finance.yahoo.com/q/bc?s=%5EDJI&t=my&l=on&z=l&q=l&c=;

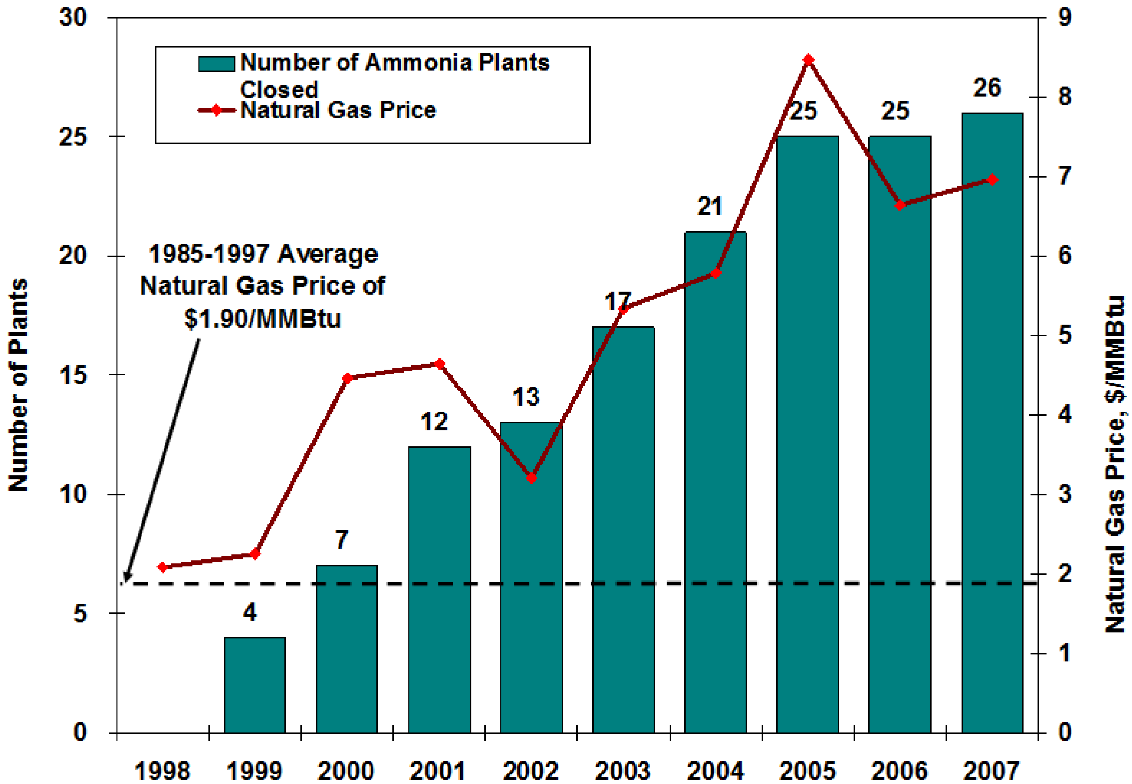
[19] Eddie Funderberg, *Why are Natural Gas Prices So High?*, available at http://www.noble.org/ag/soils/nitrogenprices/index.htm

[20] *Domestic Nitrogen Fertilizer Production Depends on Natural Gas Availability and Prices*, U.S. General Accounting Office, GA)-03-1148, September 2003.

[21] Robert Pirog, Specialist in Energy Economics, Congressional Research Service, *Industrial Demand and the Changing Natural Gas Market* February 10, 2011, available at http://www.crs.gov/pages/Reports.aspx?PRODCODE=R41628&Source=author

[22] Wen-yuan Huang, USDA, *Impact of Rising Natural Gas Prices on U.S. Ammonia Supply*, available at http://www.ers.usda.gov/publications/wrs0702/wrs0702.pdf

Figure: 3. U.S. Ammonia Plant Closures Increase as Natural Gas Prices Rise



Source: Blue, Johnson and Associates, IFDC, Natural Gas Week and The Fertilizer Institute

The harm to the U.S. economy and domestic jobs was not limited to merely the fertilizer industry. The cost of buying fertilizer to farmers rose 130 percent between 2000 and 2006, from $227 per ton to $521. Farmers get especially squeezed with higher fertilizer costs because they are often times unable to pass along higher fertilizer costs in what they charge for their commodity crops. According to the U.S. Department of Agriculture, "With lower crop prices, high fertilizer prices would place downward pressure on farmers' net returns. Farms with higher than average fertilizer costs, a greater need to use fertilizers on the crops they grow, and/or a limited ability to either move away from fertilizer-intensive crops or substitute other inputs will be especially vulnerable if fertilizer prices increase once again."[23]

[23] Wen-yuan Huang, USDA, Recent Volatility in U.S. Fertilizer Prices, available at http://www.ers.usda.gov/AmberWaves/March09/Features/FertilizerPrices.htm

With U.S. natural gas prices at 10-year lows, fertilizer production is coming back to the United States, albeit slowly. Over the past two years, several facilities have returned to production and a series of large expansions are under consideration:[24]

- Oklahoma-based LSB Industries reopened its Pryor, Oklahoma ammonia facility in 2009 and two smaller units at Pryor will restart soon as well.

- Orascom Construction has purchased and reopened a large ammonia plant in Beaumont, Texas. The company announced earlier this year that "Low natural gas prices in the U.S. were a deciding factor in the company's decision to acquire and rehabilitate the plant."

- PCS Corporation is in the process of reopening its large plant in Geismar, Louisiana with an online target in the third quarter this year. It is also considering expansions at its Lima, Ohio and Augusta, Georgia plants.

- CF Industries has reopened portions of its giant Donaldsonville, Louisiana, facility in the past two years and has purchased an additional facility. The company announced last year that it plans to invest $1 billion to $1.5 billion over the next four years to expand its production capacity for ammonia and other products.

For farmers waiting to see a drop in fertilizer prices, this new domestic production cannot come online fast enough. Even though U.S. natural gas prices have fallen to 10-year lows, fertilizer prices remain high because the United States now imports more than half of its fertilizer. Imported fertilizer comes from regions which do not have the low natural gas prices that the United States is currently enjoying, increasing the prices for farmers.[25]

Chemicals and Plastics Industry

Chemical manufacturers rely on natural gas for 58 percent of their fuel and natural gas liquids for 58 percent of their feedstock.[26] Natural gas constitutes upwards of 80 percent of the total cost to produce plastic.[27] The high natural gas prices the U.S. chemical and plastics industry faced throughout much of the last decade significantly eroded the U.S. chemicals industry's competitive position. As detailed in Figure 4, the U.S. chemical industry was essentially wiped out as an export sector between 1997 and 2006, as net exports fell from $16.8 billion annually to $218 million. Of the largest 120 chemical plants being built around the world in 2005, exactly one was located in the United States. According to the U.S. Commerce Department, "The

[24] Stephanie Seay, Platts, *Low gas costs may not be enough to spur large fertilizer expansion*, available at http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/3915346

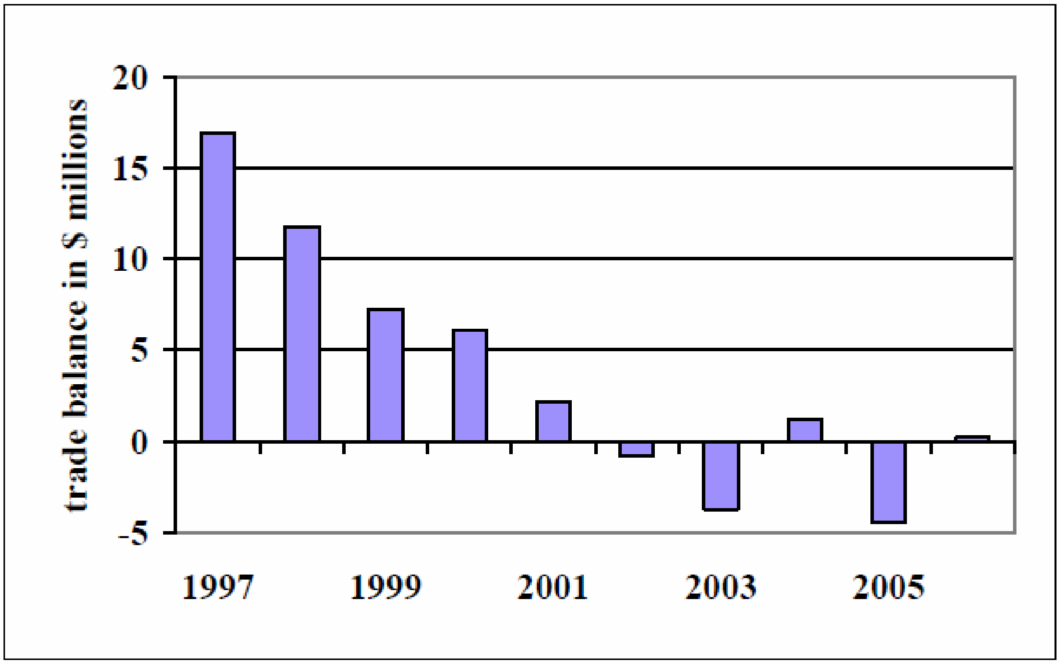
[25] Jonathan Knutson, Agweek, *Will tile drainage pay off?,* available at http://www.agweek.com/event/article/id/19564/

[26] American Chemistry Council, *Guide to the Business of Chemistry*, 2005.

[27] PowerPoint presentation "Manufacturing Competitiveness and Jobs Depend Upon Affordable and Reliable Electricity and Natural Gas," Industrial Energy Consumers of America, February 2012.

increase in U.S. natural gas prices has helped reduce and even eliminate in some recent years the United States' trade surplus in bulk chemicals."[28]

Figure 4. U.S. Trade Balance for Chemicals (not including pharmaceuticals)



Source: U.S. Department of Commerce, *Energy Policy and U.S. Industry Competitiveness. Available at: http://ita.doc.gov/td/energy/energy%20use%20by%20industry.pdf*

Appearing before the Select Committee on Energy Independence and Global Warming in 2008, the Dow Chemical Company's Vice President for Energy, Rich Wells, testified to the difficulties that the domestic chemical industry was facing. Dow had shut down dozens of uncompetitive U.S. plants in the previous decade as natural gas prices had skyrocketed. They were investing preferentially in the Middle East and other parts of the world where energy costs were lower. Wells explained that it was cheaper for chemical companies to move their manufacturing to where energy is cheap than to move cheap energy to their manufacturing.[29]

Once again, like the fertilizer sector, low domestic natural gas prices are driving a resurgence in the domestic chemical industry. According to the American Chemistry Council, "A new competitive advantage has already emerged for U.S. petrochemical producers."[30] Dow has

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[28] Rachel Halpern, International Trade Administration, *Energy Policy and U.S. Industry Competitiveness*, available at http://ita.doc.gov/td/energy/energy%20use%20by%20industry.pdf

[29] Rich Wells, Vice President Energy, The Dow Chemical Company http://globalwarming.house.gov/files/HRG/FullTranscripts/110-46_2008-07-30.pdf

[30] American Chemistry Council, *Shale Gas and New Petrochemicals Investment: Benefits for the Economy, Jobs, and US Manufacturing, March, 2011, available at* http://www.americanchemistry.com/ACC-Shale-Report

announced it will increase key chemical processing capability along the Gulf Coast by 20 to 30 percent over the next two to three years. The American Chemistry Council estimates that if natural gas-based feedstock prices stay low and supply expands, the U.S. chemical industry is projected to invest $49 billion in new plants and equipment in the United States in the coming years and spur the creation of more than 400,000 jobs across the U.S. economy. Such investments would generate $44 billion in new federal, state, and local tax revenue over the next decade.[31] Low-priced natural gas is the key to unlocking these economic benefits.

Steel Industry

The domestic steel sector's fuel reliance is split mostly between natural gas, electricity, and coal-derived coke, and the sector's natural gas consumption makes up 4 percent of U.S. industrial natural gas use.[32] The steel industry is highly energy-intensive with very tight margins, and small changes in energy prices can have a significant impact on the cost of downstream manufactured goods like automobiles, construction equipment, and wind turbines. Recycled steel is especially energy intensive, and energy can account for 25 percent or more of the cost of production.[33]

Integrated steelmakers, which produce steel from raw iron ore, use natural gas as the primary energy source for the reheating and rolling procedures at the end of the steelmaking process. Recent low natural gas prices have allowed companies to replace costly and dirty coal-derived coke with natural gas, which has become a far more cost-effective way of melting iron ore. U.S. Steel estimates that with natural gas prices around what they are today, substituting natural gas for coal-derived coke translates to savings of $7 per ton of steel.[34] A $1 per million BTU increase in the price of natural gas would increase costs by more than $100 million for U.S. Steel, based on current gas usage and steel production levels.

Another American steel producer, Nucor, has utilized low natural gas prices to build new "direct reduced iron" facilities,[35] which combine natural gas with iron ore pellets to create a steady feedstock for the company's electric arc furnaces. This is a growing technology that now accounts for more than 60 percent of steel production in the United States. Low natural gas prices are critical to operating these types of facilities. Seven years ago, as U.S. natural gas prices

[31] Id.
[32] American Iron and Steel Institute, *2010 Annual Statistical Report*, Table 37
[33] PowerPoint presentation "Manufacturing Competitiveness and Jobs Depend Upon Affordable and Reliable Electricity and Natural Gas," Industrial Energy Consumers of America, February 2012.
[34] U.S. Steel, second quarter conference call, July 26, 2011, available at http://seekingalpha.com/article/282049-united-states-steel-s-ceo-discusses-q2-2011-results-earnings-call-jul-26-2011-transcript
[35] Nucor press release, March 7, 2011, available at http://www.nucor.com/investor/news/releases/?rid=1536511

were much higher than today, Nucor relocated a facility to Trinidad in order to take advantage of "a low cost supply of natural gas."[36]

Conclusion

If we keep natural gas here at home, and keep prices low, we will accelerate the transition away from coal and foreign oil, making U.S. energy consumption not only cheaper, but cleaner and more secure.

Natural gas could eventually overtake coal as America's primary source of electricity. In just the last six years, coal's share of the U.S. electricity market has dropped from 50 percent to 43 percent, with natural gas displacing most of this production, along with wind. At the same time, buses and commercial fleet vehicles, which consume large amounts of fuel, are increasingly powered by natural gas instead of gasoline. "Replacing 3.5 million of these heavy vehicles with natural gas vehicles by 2035 would save more than 1.2 million barrels of oil per day compared to business as usual, which is more than we imported from either Venezuela or Saudi Arabia in 2009," according to a report by the Center for American Progress.[37]

Using more natural gas for electricity and transportation is expected to drive up U.S. demand by 18 percent by 2035 under current policies and commitments, "causing coal demand to drop by around 9% and oil demand by around 6%," according to the International Energy Agency.[38] This transition away from coal and foreign oil, however, could be slowed or jeopardized if we undermine our affordable domestic natural gas supply by exporting it to foreign markets.

To address these concerns Rep. Ed Markey has introduced two bills to stop natural gas from being exported. H.R. 4025 would prevent oil and gas companies from exporting natural gas extracted from public lands, and H.R. 4024 would place a moratorium on the Federal Energy Regulatory Commission approving the siting and development of LNG export terminals until 2025, except under special circumstances. Markey also offered a floor amendment to H.R. 3408, the so-called PIONEERS Act, that would have stopped the exporting of natural gas extracted from the public lands and waters opened up by the bill. That amendment failed by a vote of 173 to 254.

Instead of starting with a presumption in favor of exports, they should be evaluated against the following goals for American energy policy:

1. Keep energy affordable for American consumers;
2. Grow U.S. manufacturing and support its competitive position in the global economy;
3. Reduce America's dependence on foreign oil; and

[36] Nucor press release, January 16, 2007, available at http://www.nucor.com/investor/news/releases/?rid=950793
[37] Center for American Progress, *American Fuel: Developing Natural Gas for Heavy Vehicles*, available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf
[38] International Energy Agency, *Are We Entering a Golden Age of Gas?*, World Energy Outlook 2011, page 22, available at http://www.iea.org/weo/docs/weo2011/WEO2011_GoldenAgeofGasReport.pdf.

4. Reduce dangerous environmental pollution.

These goals are now being advanced because natural gas supplies are abundant; prices are cheaper here than abroad; and natural gas is becoming more economical than dirtier coal and imported oil. If we keep natural gas here, these benefits will continue. If we export it abroad, we will undermine each goal.

Department of Energy
Washington, DC 20585

February 24, 2012

The Honorable Edward J. Markey
Ranking Member
Committee on Natural Resources
United States House of Representatives
2108 Rayburn House Office Building
Washington, DC 20515

Dear Representative Markey:

This is in response to your letter of January 4, 2012 concerning exports of domestically produced liquefied natural gas (LNG) and the Department of Energy's (DOE) regulation of those exports. Secretary Chu asked me to respond on behalf of the Department.

DOE's Statutory Authority

DOE's authority over exports of natural gas, including LNG, arises under section 3 of the Natural Gas Act (NGA), 15 USC 717b, and section 301(b) of the DOE Organization Act, 42 USC 7151. An amendment of section 3 in the Energy Policy Act of 1992 (EPAct 92) resulted in two different sets of standards and procedures for processing applications to export LNG from the United States, including (1) standards and procedures for the export of LNG to countries with which the United States has not entered into a free trade agreement (FTA); and (2) standards and procedures for the export of LNG to countries with which the United States has entered into an FTA providing for national treatment for trade in natural gas.

FTA Export Applications

In EPAct 92, Congress amended section 3(c) to the Natural Gas Act. At that time, Congress's attention was focused on North American trade, not on the potential impact of the amendment on United States trade with other countries overseas. Section 3(c), as amended, created a different standard of review for applications to export natural gas, including LNG, to those countries with which the United States has in effect an FTA requiring national treatment for trade in natural gas. The amended section 3(c) requires such applications to be deemed consistent with the public interest, and granted without modification or delay. DOE does not have the authority to impose conditions on the resulting authorizations. The result is a bifurcated regulatory regime over which DOE has only partial control or influence.

Non-FTA Export Applications

Applications that seek authority to export LNG to non-FTA countries and all pleadings and orders in each related proceeding are posted on DOE's website where they can be viewed by the public. Upon receipt of an application, DOE issues a notice in the *Federal Register* inviting interested persons to participate and to submit argument and evidence to support their positions. After consideration of the entire record, including evidence of the environmental impact of the proposed exports, DOE issues an order supported by substantial evidence and reasoned decision-making either granting the application in whole or in part or denying the application.

NGA Section 3(a) requires DOE to grant a request to export LNG to non-FTA countries unless, after opportunity for hearing, DOE finds that the proposed export will not be consistent with the public interest. Section 3(a) thus creates a rebuttable presumption that a proposed export is in the public interest. This means that the burden is on those that oppose the application to show that it would not be consistent with the public interest.[1]

Section 3(a) also authorizes DOE to attach terms and conditions to non-FTA export authorizations to protect the public interest. In *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961 (May 20, 2011) (copy enclosed), our first order authorizing exports of lower-48 domestically produced LNG to non-FTA countries, we inserted 18 ordering paragraphs containing numerous conditions and limitations to ensure that the public interest will not be harmed by the planned exports. These terms and conditions are determined on a case by case basis, but the terms and conditions applied in *Sabine Pass* are indicative of the range of factors likely to be addressed in future such orders.

To assist in our review of the pending non-FTA export applications, DOE has commissioned a two-part study by the Energy Information Administration (EIA) and a private contractor to assess the cumulative impacts of LNG exports on a number of domestic economic factors. This effort is further described below.

Pending LNG Export Applications

An increasing number of applicants are seeking authorization from DOE to export domestic supplies of natural gas as LNG to higher-priced overseas markets. DOE presently has before it seven long-term applications to export lower-48 domestically-produced LNG to countries with which the United States does not have an FTA that requires national treatment for trade in natural gas. The volume of LNG requested for export authorization in these seven applications, plus the 2.2 billion cubic feet per day (Bcf/d) already authorized for export in *Sabine Pass*, total 12.51 Bcf/d of natural gas.

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[1] If this statutory presumption were repealed, the burden would fall on the applicant to support a claim that the proposed authorization was in the public interest. The statutory presumption in section 3(a) was enacted in 1938 at a time when the technology did not exist either to liquefy natural gas and to ship it around the world or to produce natural gas by means of enhanced production technologies such as horizontal drilling and hydraulic fracturing.

Consistent with the NGA, DOE already has granted authorization to export 10.93 Bcf/d to FTA countries. The volume authorized for export in these FTA proceedings is generally duplicative of and not in addition to the volume proposed for export in the seven pending non-FTA export applications. Also, the foreign countries with currently effective FTAs do not, in general, have the ability to receive substantial quantities of LNG from seagoing vessels.

You inquired about the domestic impact of authorizing the above-stated volume of natural gas for export. Like *Sabine Pass*, the potential impact of most of these authorizations would not be imminent because the proposed exports are not planned to commence for a number of years. Also, not all authorized exports will necessarily occur because it takes years to build LNG export facilities and numerous regulatory and financial obstacles must be cleared before a project is completed.[2] Nonetheless, cognizant of the need to review the potential impact of each of the pending applications on the assumption that each project is completed, DOE has commissioned a two-part independent study, described below.

DOE's Independent Study

DOE recognized in *Sabine Pass* that the cumulative impact of *Sabine Pass* and additional future LNG export authorizations could affect the public interest. To address this issue, DOE commissioned a two-part study. The first part, a case study conducted by the EIA, primarily evaluated the potential impact of natural gas exports on domestic natural gas supply, demand, and market prices under four scenarios of export growth rates/ultimate level of exports using EIA's National Energy Modeling System (NEMS). Each scenario was evaluated against four cases from EIA's *Annual Energy Outlook 2011,* which include varying natural gas resource assumptions and economic growth rates, for a total of 16 cases. The cases present various potential export scenarios within a wide range of probabilities. We note that NEMS is not a world energy model, and does not address the interaction between the potential for additional U.S. natural gas exports and developments in world natural gas markets. EIA has completed the first part of the study, and the report is available on its website.[3] The second part of the case study will be

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[2] In addition to DOE approval, regulatory approval must also be obtained from the Federal Energy Regulatory Commission (FERC) authorizing the siting, construction, and operation of an LNG export terminal. Other agencies, such as the U.S. Coast Guard, may also review aspects of the planned export operation. With respect to building the complex liquefaction facility, several hurdles also must be cleared in the area of project financing, securing long-term agreements to market the LNG, and negotiating with a limited number of global engineering companies that have the expertise and capability to build these types of facilities. Multiple proposals to export LNG would not necessarily, by themselves, correlate to a high volume of actual LNG exports. Five U.S. LNG import terminals were built in the mid/late-2000's; these five terminals were only a small percentage of the total number of terminals originally proposed for construction.

[3] http://www.eia.gov/analysis/requests/fe/

conducted by a private contractor, and will primarily evaluate the macroeconomic impact of these sixteen hypothetical cases.

When completed, the study will provide certain insights about (1) the potential impact of additional natural gas exports on domestic energy consumption, production, and prices; (2) the cumulative impact on the U.S. economy, including the effect on gross domestic product, job creation, balance of trade; and (3) the impact on the U.S. manufacturing sector (especially energy-intensive manufacturing industries). A copy of the tasking document from DOE's Office of Fossil Energy to EIA is included as an enclosure to this letter. General guidance given to the private contractor is also included as an enclosure to this letter.

We anticipate the study will be completed by this spring. We are mindful of the need for prompt action in each of the non-FTA LNG export proceedings before us. We are equally mindful that a sound evidentiary record is essential to reach a reasoned decision in these proceedings. As such, DOE will not issue a final order addressing the pending applications to export LNG to non-FTA countries until the full study has been completed and the Department has had an opportunity to review the results.[4] I want to emphasize that no decision has been made whether to approve, limit, phase-in, or deny the presently pending or any future proposed export authorizations. Until the study is completed, reviewed, and evaluated, it would be premature for DOE to speculate on what actions we might take or the potential impacts and effects of the pending applications on many of the issues raised in your letter.

Existing LNG Export Authorizations

You asked whether DOE would ever withdraw approvals of any previously-granted LNG export authorizations, particularly in the event of a price spike in domestic prices of natural gas. As we observed in *Sabine Pass*, DOE's authority to issue supplemental orders modifying previous authorizations is contained in NGA section 3(a) and this authority may only be exercised after opportunity for hearing and for good cause shown. DOE does not, however, intend to use this authority as a price maintenance mechanism. Moreover, DOE takes very seriously the good-faith investment-backed expectations of private parties subject to its regulatory jurisdiction. Accordingly, DOE would be reluctant to withdraw or modify a previously-granted authorization, except in the event of extraordinary circumstances. To date, DOE has not had occasion to exercise this authority.

Loss of Natural Gas into the Atmosphere

You also asked whether exporting natural gas will encourage development of production that releases natural gas into the atmosphere before technologies that prevent or reduce those releases become available.

[4]The results of the two part study will have no bearing on future DOE actions on applications to export LNG to FTA countries under NGA section 3(c).

Increased use of natural gas, using responsible production and transportation practices, will benefit the environment. Most estimates indicate that the production and use of natural gas has a lower greenhouse gas (GHG) footprint than coal or oil, the predominant alternate fuels. Therefore, insofar as natural gas offsets the consumption of coal or oil, the expanded use of natural gas will tend to reduce GHG emissions.

If you have any additional questions, please feel free to contact me or Mr. Christopher Davis, Deputy Assistant Secretary for House Affairs, at (202) 586-5450.

Sincerely,

Christopher A. Smith
Deputy Assistant Secretary
Office of Oil and Natural Gas

Enclosures

I

112TH CONGRESS
2D SESSION

H. R. 4024

To suspend approval of liquefied natural gas export terminals, and for other purposes.

IN THE HOUSE OF REPRESENTATIVES

FEBRUARY 14, 2012

Mr. MARKEY introduced the following bill; which was referred to the Committee on Energy and Commerce

---

A BILL

To suspend approval of liquefied natural gas export terminals, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE.

This Act may be cited as the "North America Natural Gas Security and Consumer Protection Act".

SEC. 2. SUSPENSION OF APPROVAL OF LNG EXPORT TERMINALS.

(a) SUSPENSION.—Before January 1, 2025, the Federal Energy Regulatory Commission may not approve any application under section 3 of the Natural Gas Act (15 U.S.C. 717b)—

(1) for the siting, construction, expansion, or operation of an LNG terminal that will be used to receive, unload, load, store, transport, gasify, liquefy, or process natural gas to be exported to a foreign country from the United States; or

(2) to amend an existing authorization of the Commission in order to modify an existing authorized facility to an LNG terminal that will be used to receive, unload, load, store, transport, gasify, liquefy, or process natural gas to be exported to a foreign country from the United States.

(b) EXEMPTIONS.—Subsection (a) shall not a apply with respect to any application described in subsection (a) if the natural gas that would be exported as a result of the approval of such application is exported solely to meet a requirement imposed pursuant to section 203 of the International Emergency Economic Powers Act (50 U.S.C. 1702), section 5(b) of the Trading with the Enemy Act (50 U.S.C. App. 5(b)), or part B of title II of the Energy Policy and Conservation Act (42 U.S.C. 6271–6276).

(c) DEFINITION OF LNG TERMINAL.—In this Act, the term "LNG terminal" has the meaning given such term in section 2(11) of the Natural Gas Act (15 U.S.C. 717a(11)).

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I

112TH CONGRESS
2D SESSION

H. R. 4025

To provide that the Secretary of the Interior may accept bids on any new oil and gas leases of Federal lands (including submerged lands) only from bidders certifying that all natural gas produced pursuant to such leases shall be offered for sale only in the United States, and for other purposes.

IN THE HOUSE OF REPRESENTATIVES

FEBRUARY 14, 2012

Mr. MARKEY (for himself and Mr. HOLT) introduced the following bill; which was referred to the Committee on Natural Resources

---

A BILL

To provide that the Secretary of the Interior may accept bids on any new oil and gas leases of Federal lands (including submerged lands) only from bidders certifying that all natural gas produced pursuant to such leases shall be offered for sale only in the United States, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE.

This Act may be cited as the "Keep American Natural Gas Here Act".

SEC. 2. NO FOREIGN SALES OF NATURAL GAS PRODUCED ON FEDERAL LANDS.

The Secretary of the Interior may accept bids on any new oil and gas leases of Federal lands (including submerged lands) under the Mineral Leasing Act (30 U.S.C. 181 et seq.) or the Outer Continental Shelf Lands Act (43 U.S.C. 1331 et seq.) only from bidders certifying that all natural gas produced pursuant to such leases shall be offered for sale only in the United States.

SEC. 3. NO FOREIGN SALES OF NATURAL GAS TRANSPORTED OVER FEDERAL PIPELINE RIGHTS-OF-WAY.

Section 28(a) of the Mineral Leasing Act (30 U.S.C. 185(a)) is amended—

(1) by inserting "(1)" after "(a)"; and

(2) by adding at the end the following:

"(2) A new right-of-way for a natural gas pipeline may not be granted under this section unless the applicant for the right-of-way certifies that all natural gas that is transported via such pipeline shall be offered for sale only in the United States.".

○

W. David Montgomery
Senior Vice President

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NERA
ECONOMIC CONSULTING

Office of Fossil Energy
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

December 3, 2012

Attn: Deputy Assistant Secretary Christopher Smith

Dear Mr. Smith

I am transmitting with this letter a clean copy of NERA's report on the macroeconomic impacts of LNG exports from the United States that was contracted for by the Department of Energy.

Sincerely,

W. David Montgomery
Senior Vice President

Enclosure

document8

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Macroeconomic Impacts of LNG Exports from the United States

NERA
Economic Consulting

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1 The opinions expressed herein do not necessarily represent the views of NERA Economic Consulting or any other NERA consultant.

Contents

Table of Figures

List of Acronyms

AEO 2011	Annual Energy Outlook 2011	GNP	Gross national product
AGR	Agricultural sector	IEA WEO	International Energy Agency World Energy Outlook
CES	Constant elasticity of substitution	IEO	International Energy Outlook
COL	Coal sector	JCC	Japanese Customs-cleared crude
CRU	Crude oil sector	LNG	Liquefied natural gas
DOE/FE	U.S. Department of Energy, Office of Fossil Energy	M_V	Motor Vehicle manufacturing sector
EIA	Energy Information Administration	MAN	Other manufacturing sector
EIS	Energy-intensive sector	Mcf	Thousand cubic feet
EITE	Energy-intensive trade exposed	MMBtu	Million British thermal units
ELE	Electricity sector	MMTPA	Million metric tonne per annum
EUR	Estimated ultimate recovery	NAICS	North American Industry Classification System
FDI	Foreign direct investment	NBP	National Balancing Point
FSU	Former Soviet Union	OIL	Refining sector
GAS	Natural gas sector	SRV	Commercial sector
GDP	Gross domestic product	Tcf	Trillion cubic feet
GIIGNL	International Group of LNG Importers	TRK	Commercial trucking sector
GNGM	Global Natural Gas Model	TRN	Other commercial transportation sector

Scenario Naming Convention

The following is the naming convention used for all the scenarios. Lists of all the possible U.S., international, U.S. LNG export, and quota rent cases are shown below.

Generic Naming Convention:

U.S. Case_International Case_U.S. LNG Export Case_Quota Rent Case

U.S. Cases:		**International Cases:**	
USREF	US Reference case	INTREF	International Reference case
HEUR	High Shale EUR	D	International Demand Shock
LEUR	Low Shale EUR	SD	International Supply/Demand Shock

U.S. LNG Export Cases

NX	No-Export Capacity	LS	Low/Slow	HS	High/Slow
LSS	Low/Slowest	LR	Low/Rapid	HR	High/Rapid
NC	No-Export Constraint				

Quota Rent Cases:

HEUR_SD_LSS_QR	US High Shale EUR with International Supply/Demand Shock at Low/Slowest export levels with quota rent
HEUR_SD_HR_QR	US High Shale EUR with International Supply/Demand Shock at High/Rapid export levels with quota rent

NewEra Baselines:

Bau_REF	No LNG export expansion case consistent with AEO 2011 Reference case
Bau_HEUR	No LNG export expansion case consistent with AEO 2011 High Shale EUR case
Bau_LEUR	No LNG export expansion case consistent with AEO 2011 Low Shale EUR case

Scenarios Analyzed by NewEra

USREF_D_LSS	US Reference case with International Demand Shock and lower than Low/Slowest export levels
USREF_D_LS	US Reference case with International Demand Shock and lower than Low/Slow export levels
USREF_D_LR	US Reference case with International Demand Shock and lower than Low/Rapid export levels
USREF_SD_LS	US Reference case with International Supply/Demand Shock at Low/Slow export levels
USREF_SD_LR	US Reference case with International Supply/Demand Shock at Low/Rapid export levels
USREF_SD_HS	US Reference case with International Supply/Demand Shock and lower than High/Slow export levels
USREF_SD_HR	US Reference case with International Supply/Demand Shock and lower than High/Rapid export levels
USREF_SD_NC	US Reference case with International Supply/Demand Shock and No Constraint on exports
HEUR_D_NC	US High Shale EUR with International Demand Shock and No Constraint on exports
HEUR_SD_LSS	US High Shale EUR with International Supply/Demand Shock at Low/Slowest export levels
HEUR_SD_LS	US High Shale EUR with International Supply/Demand Shock at Low/Slow export levels
HEUR_SD_LR	US High Shale EUR with International Supply/Demand Shock at Low/Rapid export levels
HEUR_SD_HS	US High Shale EUR with International Supply/Demand Shock at High/Slow export levels
HEUR_SD_HR	US High Shale EUR with International Supply/Demand Shock at High/Rapid export levels
HEUR_SD_NC	US High Shale EUR with International Supply/Demand Shock and No Constraint on exports
LEUR_SD_LSS	US Low Shale EUR with International Supply/Demand Shock at Low/Slowest export levels

EXECUTIVE SUMMARY

Approach

At the request of the U.S. Department of Energy, Office of Fossil Energy ("DOE/FE"), NERA Economic Consulting assessed the potential macroeconomic impact of liquefied natural gas ("LNG") exports using its energy-economy model (the "N_{ew}ERA" model). NERA built on the earlier U.S. Energy Information Administration ("EIA") study requested by DOE/FE by calibrating its U.S. natural gas supply model to the results of the study by EIA. The EIA study was limited to the relationship between export levels and domestic prices without considering whether or not those quantities of exports could be sold at high enough world prices to support the calculated domestic prices. The EIA study did not evaluate macroeconomic impacts.

NERA's Global Natural Gas Model ("GNGM") was used to estimate expected levels of U.S. LNG exports under several scenarios for global natural gas supply and demand.

NERA's N_{ew}ERA energy-economy model was used to determine the U.S. macroeconomic impacts resulting from those LNG exports.

Key Findings

This report contains an analysis of the impact of exports of LNG on the U.S. economy under a wide range of different assumptions about levels of exports, global market conditions, and the cost of producing natural gas in the U.S. These assumptions were combined first into a set of scenarios that explored the range of fundamental factors driving natural gas supply and demand. These market scenarios ranged from relatively normal conditions to stress cases with high costs of producing natural gas in the U.S. and exceptionally large demand for U.S. LNG exports in world markets. The economic impacts of different limits on LNG exports were examined under each of the market scenarios. Export limits were set at levels that ranged from zero to unlimited in each of the scenarios.

Across all these scenarios, the U.S. was projected to gain net economic benefits from allowing LNG exports. Moreover, for every one of the market scenarios examined, net economic benefits increased as the level of LNG exports increased. In particular, scenarios with unlimited exports always had higher net economic benefits than corresponding cases with limited exports.

In all of these cases, benefits that come from export expansion more than outweigh the losses from reduced capital and wage income to U.S. consumers, and hence LNG exports have net economic benefits in spite of higher domestic natural gas prices. This is exactly the outcome that economic theory describes when barriers to trade are removed.

Net benefits to the U.S. would be highest if the U.S. becomes able to produce large quantities of gas from shale at low cost, if world demand for natural gas increases rapidly, and if LNG supplies from other regions are limited. If the promise of shale gas is not fulfilled and costs of producing gas in the U.S. rise substantially, or if there are ample supplies of LNG from other regions to satisfy world demand, the U.S. would not export LNG. Under these conditions, allowing exports of LNG would cause no change in natural gas prices and do no harm to the overall economy.

U.S. natural gas prices increase when the U.S. exports LNG. But the global market limits how high U.S. natural gas prices can rise under pressure of LNG exports because importers will not purchase U.S. exports if U.S. wellhead price rises above the cost of competing supplies. In particular, the U.S. natural gas price does not become linked to oil prices in any of the cases examined.

Natural gas price changes attributable to LNG exports remain in a relatively narrow range across the entire range of scenarios. Natural gas price increases at the time LNG exports could begin range from zero to $0.33 (2010$/Mcf). The largest price increases that would be observed after 5 more years of potentially growing exports could range from $0.22 to $1.11 (2010$/Mcf). The higher end of the range is reached only under conditions of ample U.S. supplies and low domestic natural gas prices, with smaller price increases when U.S. supplies are more costly and domestic prices higher.

How increased LNG exports will affect different socioeconomic groups will depend on their income sources. Like other trade measures, LNG exports will cause shifts in industrial output and employment and in sources of income. Overall, both total labor compensation and income from investment are projected to decline, and income to owners of natural gas resources will increase. Different socioeconomic groups depend on different sources of income, though through retirement savings an increasingly large number of workers share in the benefits of higher income to natural resource companies whose shares they own. Nevertheless, impacts will not be positive for all groups in the economy. Households with income solely from wages or government transfers, in particular, might not participate in these benefits.

Serious competitive impacts are likely to be confined to narrow segments of industry. About 10% of U.S. manufacturing, measured by value of shipments, has both energy expenditures greater than 5% of the value of its output and serious exposure to foreign competition. Employment in industries with these characteristics is about one-half of one percent of total U.S. employment.

LNG exports are not likely to affect the overall level of employment in the U.S. There will be some shifts in the number of workers across industries, with those industries associated with natural gas production and exports attracting workers away from other industries. In no scenario is the shift in employment out of any industry projected to be larger than normal rates of turnover of employees in those industries.

I. SUMMARY

A. What NERA Was Asked to Do

NERA Economic Consulting was asked by the DOE/FE to use its N_{ew}ERA model to evaluate the macroeconomic impact of LNG exports. NERA's analysis follows on from the study of impacts of LNG exports on U.S. natural gas prices performed by the U.S. EIA "Effect of Increased Natural Gas Exports on Domestic Energy Markets," hereafter referred to as the "EIA Study."[2]

NERA's analysis addressed the same 16 scenarios for LNG exports analyzed by EIA. These scenarios incorporated different assumptions about U.S. natural gas supply and demand and different export levels as specified by DOE/FE:

- U.S. scenarios: Reference, High Demand, High Natural Gas Resource, and Low Natural Gas Resource cases.
- U.S. LNG export levels reflecting either slow or rapid increases to limits of
    - Low Level: 6 billion cubic feet per day
    - High Level: 12 billion cubic feet per day

DOE also asked NERA to examine a lower export level, with capacity rising at a slower rate to 6 billion cubic feet per day and cases with no export constraints.

The EIA study was confined to effects of specified levels of exports on natural gas prices within the U.S. EIA was not asked to estimate the price that foreign purchasers would be willing to pay for the specified quantities of exports. The EIA study, in other words, was limited to the relationship between export levels and domestic prices without, for example, considering whether or not those quantities of exports could be sold at high enough world prices to support the calculated domestic prices. Thus before carrying out its macroeconomic analysis, NERA had to estimate the export or world prices at which various quantities of U.S. LNG exports could be sold on the world market. This proved quite important in that NERA concluded that in many cases, the world natural gas market would not accept the full amount of exports assumed in the EIA scenarios at export prices high enough to cover the U.S. wellhead domestic prices calculated by the EIA.

To evaluate the feasibility of exporting the specified quantities of natural gas, NERA developed additional scenarios for global natural gas supply and demand, yielding a total of 63 scenarios when the global and U.S. scenarios were combined. NERA then used the GNGM to estimate the market-determined export price that would be received by exporters of natural gas from the United States in the combined scenarios.

NERA selected 13 of these scenarios that spanned the range of economic impacts from all the scenarios for discussion in this report and eliminated scenarios that had essentially identical

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[2] Available at: www.eia.gov/analysis/requests/fe/.

outcomes for LNG exports and prices.[3] These scenarios are described in Figure 1. NERA then analyzed impacts on the U.S. economy of these levels of exports and the resulting changes in the U.S. trade balance and in natural gas prices, supply, and demand.

Figure 1: Feasible Scenarios Analyzed in the Macroeconomic Model

U.S. Market Outlook	**Reference**		**High Shale EUR**		**Low Shale EUR**	
Int'l Market Outlook	**Demand Shock**	**Supply/ Demand Shock**	**Demand Shock**	**Supply/ Demand Shock**	**Demand Shock**	**Supply/ Demand Shock**
Export Volume/ Pace	**Scenario Name**					
Low/Slow	**USREF_D_LS**	*USREF_SD_LS*		*HEUR_SD_LS*		
Low/Rapid	**USREF_D_LR**	*USREF_SD_LR*		*HEUR_SD_LR*		
High/Slow		**USREF_SD_HS**		*HEUR_SD_HS*		
High/Rapid		**USREF_SD_HR**		*HEUR_SD_HR*		
Low/ Slowest	**USREF_D_LSS**			*HEUR_SD_LSS*		**LEUR_SD_LSS**

Scenarios in italics use DOE/FE defined export volumes.
Scenarios in bold use NERA determined export volumes.
Results for all cases are provided in Appendix C.

The three scenarios chosen for the U.S. resource outlook were the EIA Reference cases, based on the Annual Energy Outlook ("AEO") 2011, and two cases assuming different levels of estimated ultimate recovery ("EUR") from new gas shale development. Outcomes of the EIA high demand case fell between the high and low EUR cases and therefore would not have changed the range of results. The three different international outlooks were a reference case, based on the EIA International Energy Outlook ("IEO") 2011, a Demand Shock case with increased worldwide natural gas demand caused by shutdowns of some nuclear capacity, and a Supply/Demand Shock case which added to the Demand Shock a supply shock that assumed key LNG exporting regions did not increase their exports above current levels.

NERA concluded that in many cases the world natural gas market would not accept the full amount of exports specified by FE in the EIA scenarios at prices high enough to cover the U.S. wellhead price projected by EIA. In particular, NERA found that there would be no U.S. exports in the International Reference case with U.S. Reference case conditions. In the U.S. Reference case with an International Demand Shock, exports were projected but in quantities below any of the export limits. In these cases, NERA replaced the export levels specified by DOE/FE and prices estimated by EIA with lower levels of exports (and, *a fortiori* prices) estimated by GNGM

[3] The scenarios not presented in this report had nearly identical macroeconomic impacts to those that are included, so that the number of scenarios discussed could be reduced to make the exposition clearer and less duplicative.

that are indicated in bold black in Figure 1. For sensitivity analysis, NERA also examined cases projecting zero exports and also cases with no limit placed on exports.

B. Key Assumptions

All the scenarios were derived from the AEO 2011, and incorporated the assumptions about energy and environmental policies, baseline coal, oil and natural gas prices, economic and energy demand growth, and technology availability and cost in the corresponding AEO cases.

The global LNG market was treated as a largely competitive market with one dominant supplier, Qatar, whose decisions about exports were assumed to be fixed no matter what the level of U.S. exports. U.S. exports compete with those from the other suppliers, who are assumed to behave as competitors and adjust their exports in light of the price they are offered. In this market, LNG exports from the U.S. necessarily lower the price received by U.S. exporters below levels that might be calculated based on current prices or prices projected without U.S exports, and in particular U.S. natural gas prices do not become linked to world oil prices.

It is outside the scope of this study to analyze alternative responses by other LNG suppliers in order to determine what would be in their best economic interest or how they might behave strategically to maximize their gains. This would require a different kind of model that addresses imperfect competition in global LNG markets and could explain the apparent ability of some large exporters to charge some importing countries at prices higher than the cost of production plus transportation.

Key assumptions in analyzing U.S. economic impacts were as follows: prices for natural gas used for LNG production were based on the U.S. wellhead price plus a percentage markup, the LNG tolling fee was based on a return of capital to the developer, and financing of investment was assumed to originate from U.S. sources. In order to remain consistent with the EIA analysis, the N_{ew}ERA model was calibrated to give the same results for natural gas prices as EIA at the same levels of LNG exports so that the parameters governing natural gas supply and demand in N_{ew}ERA were consistent with EIA's NEMS model.

Results are reported in 5-year intervals starting in 2015. These calendar years should not be interpreted literally but represent intervals after exports begin. Thus if the U.S. does not begin LNG exports until 2016 or later, one year should be added to the dates for each year that exports commence after 2015.

Like other general equilibrium models, N_{ew}ERA is a model of long run economic growth such that in any given year, prices, employment, or economic activity might fluctuate above or below projected levels. It is used in this study not to give unconditional forecasts of natural gas prices, but to indicate how, under different conditions, different decisions about levels of exports would affect the performance of the economy. In this kind of comparison, computable general equilibrium models generally give consistent and robust results.

Consistent with its equilibrium nature, N_{ew}ERA does not address questions of how rapidly the economy will recover from the recession and generally assumes that aggregate unemployment rates remain the same in all cases. As is discussed below, N_{ew}ERA does estimate changes in worker compensation in total and by industry that can serve as an indicator of pressure on labor markets and displacement of workers due to some industries growing more quickly and others less quickly than assumed in the baseline.

C. Key Results

1. Impacts of LNG Exports on U.S. Natural Gas Prices

In its analysis of global markets, NERA found that the U.S. would only be able to market LNG successfully with higher global demand or lower U.S. costs of production than in the Reference cases. The market limits how high U.S. natural gas prices can rise under pressure of LNG exports because importers will not purchase U.S. exports if the U.S. wellhead price rises above the cost of competing supplies. In particular, the U.S. natural gas price does not become linked to oil prices in any of the cases examined.

2. Macroeconomic Impacts of LNG Exports are Positive in All Cases

In all of the scenarios analyzed in this study, NERA found that the U.S. would experience net economic benefits from increased LNG exports.[4] Only three of the cases analyzed with the global model had U.S. exports greater than the 12Bcf/d maximum exports allowed in the cases analyzed by EIA. These were the USREF_SD, the HEUR_D and the HEUR_SD cases. NERA estimated economic impacts for these three cases with no constraint on exports, and found that even with exports reaching levels greater than 12 Bcf/d and associated higher prices than in the constrained cases, there were net economic benefits from allowing unlimited exports in all cases.

Across the scenarios, U.S. economic welfare consistently increases as the volume of natural gas exports increased. This includes scenarios in which there are unlimited exports. The reason for this is that even though domestic natural gas prices are pulled up by LNG exports, the value of those exports also rises so that there is a net gain for the U.S. economy measured by a broad metric of economic welfare (Figure 2) or by more common measures such as real household income or real GDP. Although there are costs to consumers of higher energy prices and lower consumption and producers incur higher costs to supply the additional natural gas for export, these costs are more than offset by increases in export revenues along with a wealth transfer from overseas received in the form of payments for liquefaction services. The net result is an increase in U.S. households' real income and welfare.[5]

Net benefits to the U.S. economy could be larger if U.S. businesses were to take more of a merchant role. Based on business models now being proposed, this study assumes that foreign

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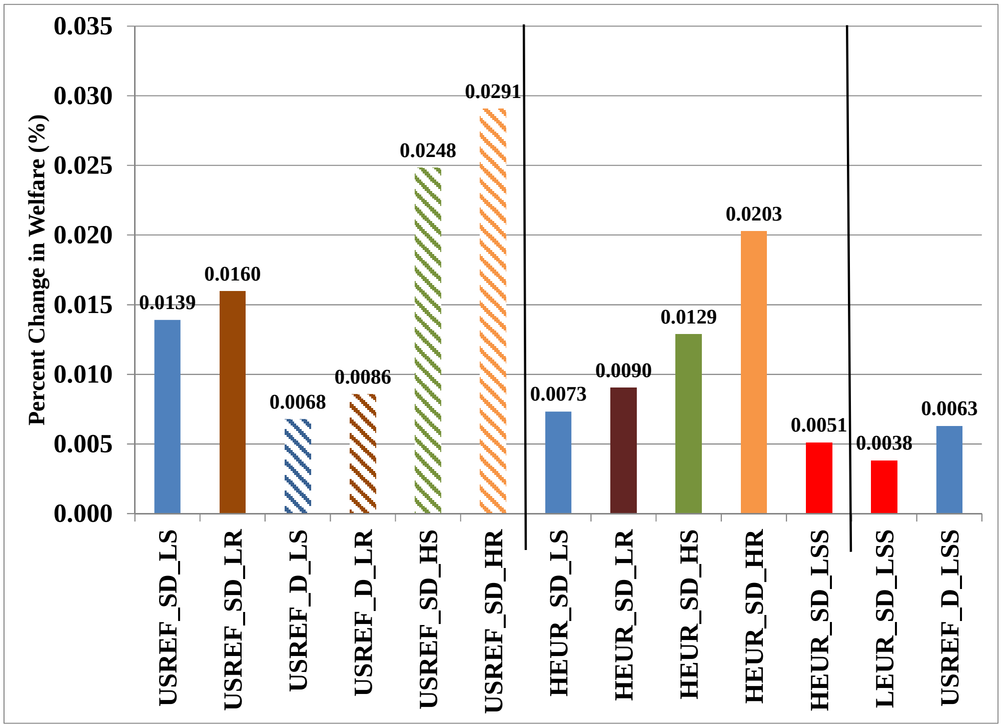
[4] NERA did not run the EIA High Growth case because the results would be similar to the REF case.

[5] In this report, the measure of welfare is technically known as the "equivalent variation" and it is the amount of income that a household would be willing to give up in the case without LNG exports in order to achieve the benefits of LNG exports. It is measured in present value terms, and therefore captures in a single number benefits and costs that might vary year by year over the period.

purchasers take title to LNG when it is loaded at a United States port, so that any profits that could be made by transporting and selling in importing countries accrue to foreign entities. In the cases where exports are constrained to maximum permitted levels, this business model sacrifices additional value from LNG exports that could accrue to the United States.

Figure 2: Percentage Change in Welfare (%)[6]



3. Sources of Income Would Shift

At the same time that LNG exports create higher income in total in the U.S., they shift the composition of income so that both wage income and income from capital investment are reduced. Our measure of total income is GDP measured from the income side, that is, by adding up income from labor, capital and natural resources and adjusting for taxes and transfers. Expansion of LNG exports has two major effects on income: it raises energy costs and, in the process, depresses both real wages and the return on capital in all other industries, but it also creates two additional sources of income. First, additional income comes in the form of higher export revenues and wealth transfers from incremental LNG exports at higher prices paid by overseas purchasers. Second, U.S. households also benefit from higher natural gas resource income or rents. These benefits distinctly differentiate market-driven expansion of LNG exports from actions that only raise domestic prices without creating additional sources of income. The benefits that come from export expansion more than outweigh the losses from reduced capital and wage income to U.S. consumers, and hence LNG exports have net economic benefits in spite

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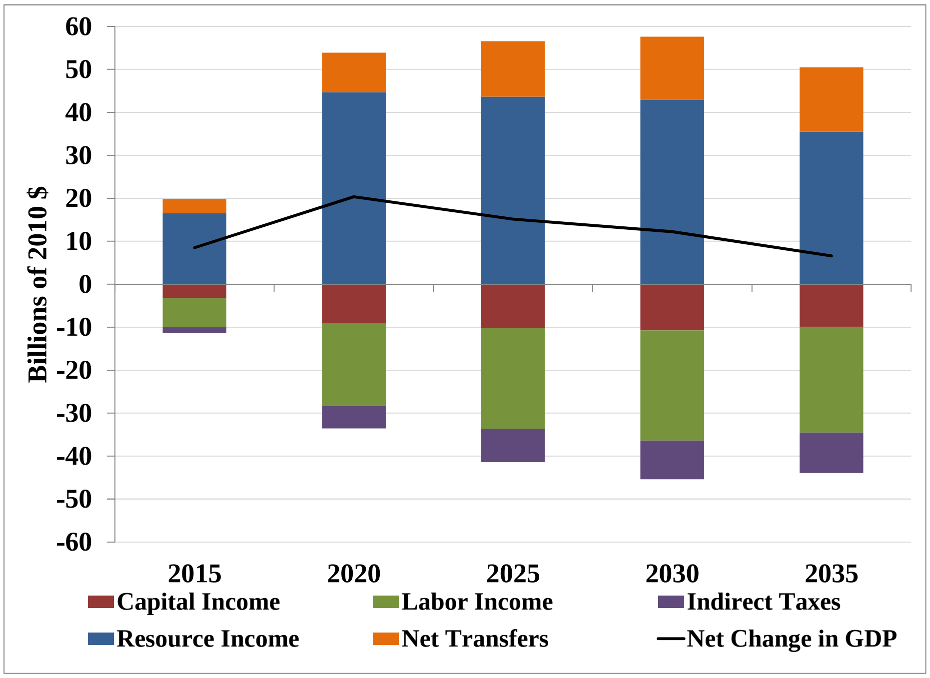
6 Welfare is calculated as a single number that represents in present value terms the amount that households are made better (worse) off over the entire time horizon from 2015 to 2035.

of higher natural gas prices. This is exactly the outcome that economic theory describes when barriers to trade are removed.

Figure 3 illustrates these shifts in income components for the USREF_SD_HR scenario, though the pattern is the same in all. First, Figure 3 shows that GDP increases in all years in this case, as it does in other cases (see Appendix C). Labor and investment income are reduced by about $10 billion in 2015 and $45 billion in 2030, offset by increases in resource income to natural gas producers and property owners and by net transfers that represent that improvement in the U.S. trade balance due to exporting a more valuable product (natural gas). Note that these are positive but, on the scale of the entire economy, very small net effects.

Figure 3: Change in Income Components and Total GDP in USREF_SD_HR (Billions of 2010$)



4. Some Groups and Industries Will Experience Negative Effects of LNG Exports

Different socioeconomic groups depend on different sources of income, though through retirement savings an increasingly large number of workers will share in the benefits of higher income to natural resource companies whose shares they own. Nevertheless, impacts will not be positive for all groups in the economy. Households with income solely from wages or transfers, in particular, will not participate in these benefits.

Higher natural gas prices in 2015 can also be expected to have negative effects on output and employment, particularly in sectors that make intensive use of natural gas, while other sectors not so affected could experience gains. There would clearly be greater activity and employment in natural gas production and transportation and in construction of liquefaction facilities. Figure

4 shows changes in total wage income for the natural gas sector and for other key sectors[7] of the economy in 2015. Overall, declines in output in other sectors are accompanied by similar reductions in worker compensation in those sectors, indicating that there will be some shifting of labor between different industries. However, even in the year of peak impacts the largest change in wage income by industry is no more than 1%, and even if all of this decline were attributable to lower employment relative to the baseline, no sector analyzed in this study would experience reductions in employment more rapid than normal turnover. In fact, most of the changes in real worker compensation are likely to take the form of lower than expected real wage growth, due to the increase in natural gas prices relative to nominal wage growth.

Figure 4: Change in Total Wage Income by Industry in 2015 (%)

	AGR	EIS	ELE	GAS	M_V	MAN	OIL	SRV
USREF_SD_LS	-0.12	-0.13	-0.06	0.88	-0.10	-0.08	0.01	0.00
USREF_SD_LR	-0.22	-0.28	-0.18	2.54	-0.24	-0.19	0.01	-0.04
USREF_D_LS	-0.08	-0.10	-0.06	0.87	-0.08	-0.07	0.00	-0.01
USREF_D_LR	-0.18	-0.23	-0.16	2.35	-0.21	-0.16	0.00	-0.05
USREF_SD_HS	-0.15	-0.18	-0.06	0.88	-0.11	-0.10	0.01	0.00
USREF_SD_HR	-0.27	-0.33	-0.18	2.54	-0.26	-0.22	0.01	-0.03
USREF_D_LSS	-0.06	-0.07	-0.03	0.43	-0.05	-0.04	0.00	0.00
HEUR_SD_LS	-0.10	-0.11	-0.05	0.71	-0.09	-0.07	0.01	0.00
HEUR_SD_LR	-0.19	-0.23	-0.16	2.04	-0.22	-0.16	0.00	-0.04
HEUR_SD_HS	-0.12	-0.14	-0.05	0.71	-0.09	-0.08	0.01	0.00
HEUR_SD_HR	-0.25	-0.30	-0.16	2.05	-0.25	-0.20	0.01	-0.02
HEUR_SD_LSS	-0.06	-0.07	-0.02	0.35	-0.04	-0.04	0.00	0.00
LEUR_SD_LSS	-0.02	-0.02	0.00	0.00	0.00	-0.01	0.00	0.01

5. Peak Natural Gas Export Levels, Specified by DOE/FE for the EIA Study, and Resulting Price Increases Are Not Likely

The export volumes selected by DOE/FE for the EIA Study define the maximum exports allowed in each scenario for the NERA macroeconomic analysis. Based on its analysis of global natural gas supply and demand under different assumptions, NERA projected achievable levels of exports for each scenario. The NERA scenarios that find a lower level of exports than the limits specified by DOE are shown in Figure 5. The cells in italics (red) indicate the years in which the

[7] Other key sectors of the economy include: AGR – Agriculture, EIS-Energy Intensive Sectors, ELE-Electricity, GAS-Natural gas, M_V-Motor Vehicle, MAN-Manufacturing, OIL-Refined Petroleum Products, and SRV-Services.

limit on exports is binding.[8] All scenarios hit the export limits in 2015 except the NERA export volume case with Low/Rapid exports.

Figure 5: NERA Export Volumes (Tcf)

NERA Export Volumes	2015	2020	2025	2030	2035
USREF_D_LS	***0.37***	0.98	1.43	1.19	***2.19***
USREF_D_LR	1.02	0.98	1.43	1.19	1.37
USREF_SD_HS	***0.37***	2.19	3.93	***4.38***	***4.38***
USREF_SD_HR	***1.1***	***2.92***	3.93	***4.38***	***4.38***
USREF_D_LSS	***0.18***	0.98	1.43	1.19	1.37

As seen in Figure 6, in no case does the U.S. wellhead price increase by more than $1.09/Mcf due to market-determined levels of exports. Even in cases in which no limits were placed on exports, competition between the U.S. and competing suppliers of LNG exports and buyer resistance limits increases in both U.S. LNG exports and U.S. natural gas prices.

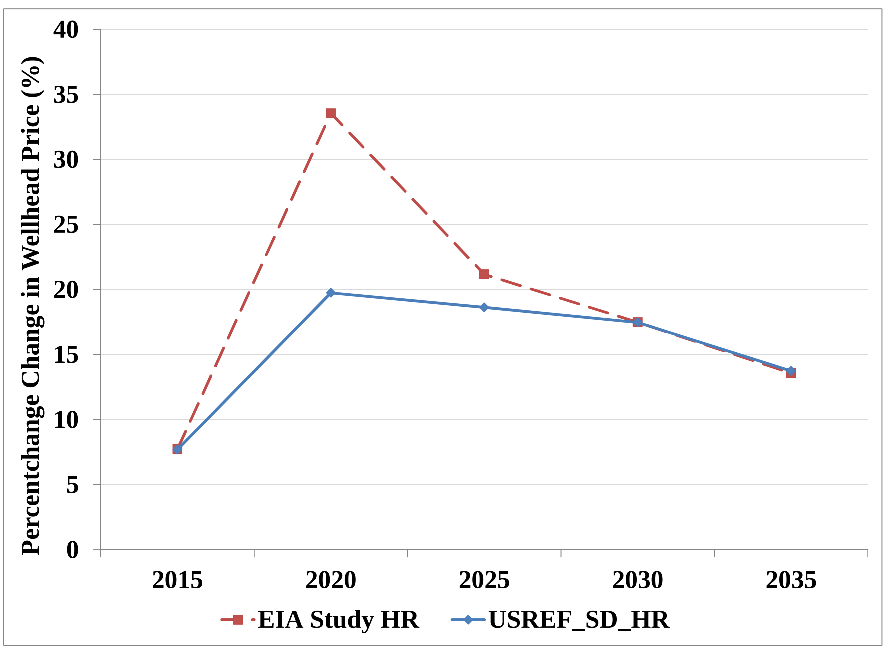
To match the characterization of U.S. supply and demand for natural gas in EIA's NEMS model, NERA calibrated its macroeconomic model so that for the same level of LNG exports as assumed in the EIA Study, the NERA model reproduced the prices projected by EIA. Thus natural gas price responses were similar in scenarios where NERA export volumes were at the EIA export volumes. However, the current study determined that the high export limits were not economic in the U.S. Reference case and that in these scenarios there would be lower exports than assumed by EIA. Because the current study estimated lower export volumes than were specified by FE for the EIA study, U.S. natural gas prices do not reach the highest levels projected by EIA (see Figure 7).

[8] The U.S. LNG export capacity binds when the market equilibrium level of exports as determined by the model exceeds the maximum LNG export capacity assumed in that scenario.

Figure 6: Prices and Export Levels in Representative Scenarios for Year 2035

U.S. Scenarios	International Scenarios	Quota Scenarios	U.S. Wellhead Price (2010$/Mcf)	U.S. Export (Tcf)	Price Relative to Reference case (2010$/Mcf)
USREF	INTREF	NX	$6.41		
USREF	INTREF	NC	$6.41	0	$0.00
USREF	D	HR	$6.66	1.37	$0.25
USREF	D	NC	$6.66	1.37	$0.25
USREF	SD	HR	$7.24	4.38	$0.83
USREF	SD	NC	$7.50	5.75	$1.09
HEUR	INTREF	NX	$4.88		
HEUR	INTREF	LR	$5.16	2.19	$0.28
HEUR	INTREF	NC	$5.31	3.38	$0.43
HEUR	D	NC	$5.60	5.61	$0.72
HEUR	SD	LSS	$5.16	2.19	$0.28
HEUR	SD	NC	$5.97	8.39	$1.09
LEUR	INTREF	NX	$8.70		
LEUR	INTREF	NC	$8.70	0	$0.00
LEUR	D	NC	$8.70	0	$0.00
LEUR	SD	NC	$8.86	0.52	$0.16

Figure 7: Comparison of EIA and NERA Maximum Wellhead Price Increases



The reason is simple and implies no disagreement between this report and EIA's - the analysis of world supply and demand indicates that at the highest wellhead prices estimated by EIA, world demand for U.S. exports would fall far short of the levels of exports assumed in the EIA Study.

In none of the scenarios analyzed in this study do U.S. wellhead prices become linked to oil prices in the sense of rising to oil price parity, even if the U.S. is exporting to regions where natural gas prices are linked to oil. The reason is that costs of liquefaction, transportation, and regasification keep U.S. prices well below those in importing regions.

6. Serious Competitive Impacts are Likely to be Confined to Narrow Segments of Industry

About 10% of U.S. manufacturing, measured by value of shipments, has energy expenditures greater than 5% of the value of its output and serious exposure to foreign competition. Employment in industries with these characteristics is one-half of one percent of total U.S. employment. These energy-intensive, trade-exposed industries for the most part process raw natural resources into bulk commodities. Value added in these industries as a percentage of value of shipments is about one-half of what it is in the remainder of manufacturing. In no scenario are energy-intensive industries as a whole projected to have a loss in employment or output greater than 1% in any year, which is less than normal rates of turnover of employees in the relevant industries.

7. Even with Unlimited Exports, There Would Be Net Economic Benefits to the U.S.

NERA also estimated economic impacts associated with unlimited exports in cases in which even the High, Rapid limits were binding. In these cases, both LNG exports and prices were determined by global supply and demand. Even in these cases, U.S. natural gas prices did not rise to oil parity or to levels observed in consuming regions, and net economic benefits to the U.S. increased over the corresponding cases with limited exports.

To examine U.S. economic impacts under cases with even higher natural gas prices and levels of exports than in the unlimited export cases, NERA also estimated economic impacts associated with the highest levels of exports and U.S. natural gas prices in the EIA analysis, regardless of whether or not those quantities could actually be sold at the assumed netback prices. The price received for exports in these cases was calculated in the same way as in the cases based on NERA's GNGM, by adding the tolling fee plus a 15% markup over Henry Hub to the Henry Hub price. Even with the highest prices estimated by EIA for these hypothetical cases, NERA found that there would be net economic benefits to the U.S., and the benefits became larger, the higher the level of exports. This is because the export revenues from sales to other countries at those high prices more than offset the costs of freeing that gas up for export.

II. INTRODUCTION

This section describes the issues that DOE/FE asked to be addressed in this study and then describes the scope of both the EIA Study and the NERA analysis that make up the two-part study commissioned by the DOE/FE.

A. Statement of the Problem

1. At What Price Can Various Quantities of LNG Exports be Sold?

An analysis of U.S. LNG export potential requires consideration of not only the impact of additional demand on U.S. production costs, but also consideration of the price levels that would make U.S. LNG economical in the world market. For the U.S. natural gas market, LNG exports would represent an additional component of natural gas demand that must be met from U.S. supplies. For the global market, U.S. LNG exports represent another component of supply that must compete with supply from other regions of the world. As the demand for U.S. natural gas increases, so will the cost of producing incremental volumes. But U.S. LNG exports will compete with LNG produced from other regions of the world. At some U.S. price level, it will become more economic for a region other than the U.S. to provide the next unit of natural gas to meet global demand. A worldwide natural gas supply and demand model assists in determining under what conditions and limits this pricing point is reached.

2. What are the Economic Impacts on the U.S. of LNG Exports?

U.S. LNG exports have positive impacts on some segments of the U.S. economy and negative impacts on others. On the positive side, U.S. LNG exports provide an opportunity for natural gas producers to realize additional profits by selling incremental volumes of natural gas. Exports of natural gas will improve the U.S. balance of trade and result in a wealth transfer into the U.S. Construction of the liquefaction facilities to produce LNG will require capital investment. If this capital originates from sources outside the U.S., it will represent another form of wealth transfer into the U.S. Households will benefit from the additional wealth transferred into the U.S. If they, or their pensions, hold stock in natural gas producers, they will benefit from the increase in the value of their investment.

On the negative side, producing incremental natural gas volumes will increase the marginal cost of supply and therefore raise domestic natural gas prices and increase the value of natural gas in general. Households will be negatively affected by having to pay higher prices for the natural gas they use for heating and cooking. Domestic industries for which natural gas is a significant component of their cost structure will experience increases in their cost of production, which will adversely impact their competitive position in a global market and harm U.S. consumers who purchase their goods.

Natural gas is also an important fuel for electricity generation, providing about 20% of the fuel inputs to electricity generation. Moreover, in many regions and times of the year natural gas-fired generation sets the price of electricity so that increases in natural gas prices can impact electricity prices. These price increases will also propagate through the economy and affect both household energy bills and costs for businesses.

B. Scope of NERA and EIA Study

NERA Economic Consulting was asked by the U.S. DOE/FE to evaluate the macroeconomic impact of LNG exports using a general equilibrium model of the U.S. economy with an emphasis on the energy sector and natural gas in particular. NERA incorporated the U.S. EIA's case study output from the National Energy Modeling System ("NEMS") into the natural gas production module in its N_{ew}ERA model by calibrating natural gas supply and cost curves in the N_{ew}ERA macroeconomic model. NERA's task was to use this model to evaluate the impact that LNG exports could have on multiple economic factors, primarily U.S. gross domestic product ("GDP"), employment, and real income. The complete statement of work is attached as Appendix F.

1. EIA Study

The DOE/FE requested that the U.S. EIA perform an analysis of "the impact of increased domestic natural gas demand, as exports."[9] Specifically, DOE/FE asked the EIA to assess how specified scenarios of increased natural gas exports could affect domestic energy markets, focusing on consumption, production, and prices.

DOE/FE requested that EIA analyze four scenarios of LNG export-related increases in natural gas demand:

1. 6 billion cubic feet per day (Bcf/d), phased in at a rate of 1 Bcf/d per year (Low/Slow scenario);

2. 6 Bcf/d phased in at a rate of 3 Bcf/d per year (Low/Rapid scenario);

3. 12 Bcf/d phased in at a rate of 1 Bcf/d per year (High/Slow scenario); and

4. 12 Bcf/d phased in at a rate of 3 Bcf/d per year (High/Rapid scenario).

Total U.S. marketed natural gas production in 2011 was about 66 Bcf/d. Additional LNG exports at 6 Bcf/d represents roughly 9 percent of current production and 12 Bcf/d represents roughly18 percent of current production.

DOE/FE requested that EIA analyze for each of the four LNG export scenarios four cases from the EIA AEO 2011. These scenarios reflect different perspectives on the domestic natural gas supply situation and the growth rate of the U.S. economy. These are:

1. The AEO 2011 Reference case;

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9 U.S. EIA, "Effects of Increased Natural Gas Exports on Domestic Energy Markets," p. 20.

2. The High Shale EUR case (reflecting more optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent higher than in the Reference case);

3. The Low Shale EUR case (reflecting less optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent lower than in the Reference case); and

4. The High Economic Growth case (assuming the U.S. gross domestic product will grow at an average annual rate of 3.2 percent from 2009 to 2035, compared to 2.7 percent in the Reference case, which increases domestic energy demand).

In January 2012, EIA released the results of its analysis in a report entitled "Effect of Increased Natural Gas Exports on Domestic Energy Markets," hereafter referred to as the "EIA Study".

2. NERA Study

NERA relied on the EIA Study to characterize how U.S. natural gas supply, demand, and prices would respond if the specified levels of LNG exports were achieved. However, the EIA study was not intended to address the question of how large the demand for U.S. LNG exports would be under different wellhead prices in the United States. That became the first question that NERA had to answer: at what price could U.S. LNG exports be sold in the world market, and how much would this price change as the amount of exports offered into the world market increased?

NERA's analysis of global LNG markets leads to the conclusion that in many cases the world market would not accept the full amount assumed in the EIA scenarios at prices high enough to cover the U.S. wellhead price projected by EIA. In these cases, NERA replaced the export levels and price impacts found in the EIA scenarios with lower levels of exports (and *a fortiori* prices) estimated by the GNGM. These lower export levels were applied to the N_{ew}ERA model to generate macroeconomic impacts. In order to remain tied to the EIA analysis, the N_{ew}ERA model was calibrated to give the same natural gas price responses as EIA for the same assumptions about the level of LNG exports. This was done by incorporating in N_{ew}ERA the same assumptions about how U.S. natural gas supply and demand would be affected by changes in the U.S. natural gas wellhead price as implied by the NEMS model used in the EIA study.

C. Organization of the Report

This report begins by discussing what NERA was asked to do and the methodology followed by NERA. This discussion of methodology includes the key assumptions made by NERA in its analysis and a description of the models utilized. Then construction of scenarios for U.S. LNG exports is described, followed by presentation of the results and a discussion of their economic implications.

III. DESCRIPTION OF WORLDWIDE NATURAL GAS MARKETS AND NERA'S ANALYTICAL MODELS

A. Natural Gas Market Description

1. Worldwide

The global natural gas market consists of a collection of distinctive regional markets. Each regional market is characterized by its location, availability of indigenous resource, pipeline infrastructure, accessibility to natural gas from other regions of the world, and its rate of growth in natural gas demand. Some regions are connected to other regions by pipelines, others by LNG facilities, and some operate relatively autonomously.

In general, a region will meet its natural gas demand first with indigenous production, second with gas deliveries by pipelines connected to other regions, and third with LNG shipments. In 2010, natural gas consumption worldwide reached 113 Tcf. As shown in Figure 8, most natural gas demand in a region is met by natural gas production in the same region. In 2010, approximately 9.7 Tcf or almost 9% of demand was met by LNG.

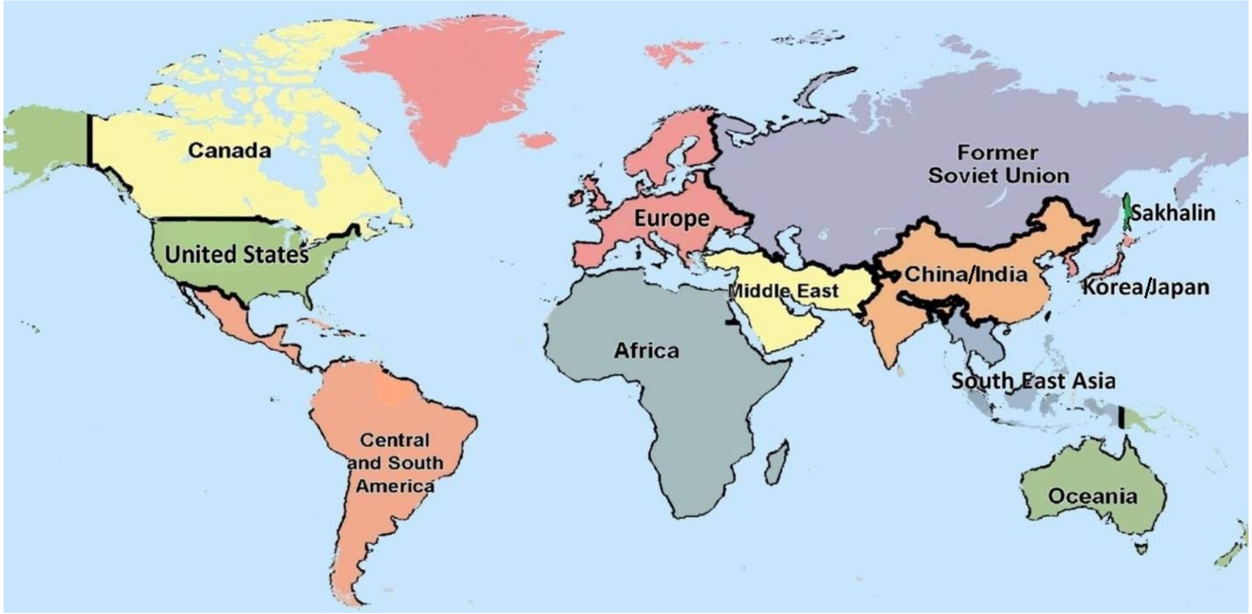
Figure 8: Global Natural Gas Demand and Production (Tcf)

	Production	Consumption
Africa	7.80	3.90
Canada	6.10	3.30
China/India	4.60	5.70
C&S America	6.80	6.60
Europe	9.50	19.20
FSU	28.87	24.30
Korea/Japan	0.20	5.00
Middle East	16.30	12.50
Oceania	2.10	1.20
Sakhalin	0.43	0.00
Southeast Asia	9.30	7.40
U.S.	21.10	23.80
Total World	113.10	112.90

Some regions are rich in natural gas resources and others are experiencing rapid growth in demand. The combination of these two characteristics determines whether the region operates as a net importer or exporter of natural gas. The characteristics of a regional market also have an impact on natural gas pricing mechanisms. The following describes the characteristics of the regional natural gas markets considered in this report.

We present our discussion in terms of regions because we have grouped countries into major exporting, importing, and demand regions for our modeling purposes. For our analysis, we grouped the world into 12 regions: U.S., Canada, Korea/Japan, China/India, Europe, Oceania, Southeast Asia, Africa, Central and South America, former Soviet Union, Middle East and Sakhalin. These regions are shown in Figure 9.

Figure 9: Regional Groupings for the Global Natural Gas Model



Japan and Korea are countries that have little indigenous natural gas resource and no prospects for gas pipelines connecting to other regions. Both countries depend almost entirely upon LNG imports to meet their natural gas demand. As a result, both countries are very dependent upon reliable sources of LNG. This is reflective in their contracting practices and willingness to have LNG prices tied to petroleum prices (petroleum is a potential substitute for natural gas). This dependence would become even more acute if Japan were to implement a policy to move away from nuclear power generation and toward greater reliance on natural gas-fired generation.

In contrast, China and India are countries that do have some indigenous natural gas resources, but these resources alone are insufficient to meet their natural gas demand. Both countries are situated such that additional natural gas pipelines from other regions of the world could possibly be built to meet a part of their natural gas needs, but such projects face geopolitical challenges. Natural gas demand in these countries is growing rapidly as a result of expanding economies, improving wealth and a desire to use cleaner burning fuels. LNG will be an important component of their natural gas supply portfolio. These countries demand more than they can produce and the pricing mechanism for their LNG purchases reflects this.

Europe also has insufficient indigenous natural gas production to meet its natural gas demand. It does, however, have extensive pipeline connections to both Africa and the Former Soviet Union ("FSU"). Despite having a gap between production and consumption, Europe's growth in natural gas demand is modest. As a result, LNG is one of several options for meeting natural gas demand. The competition among indigenous natural gas supplies, pipeline imports, and LNG imports has resulted in a market in which there is growing pressure to move away from petroleum index pricing toward natural gas index pricing.

FSU is one of the world's leading natural gas producers. It can easily accommodate its own internal natural gas demand in part because of its slow demand growth. It has ample natural gas supplies that it exports by pipeline (in most instances pipelines, if practical, are a more economical method to transport natural gas than LNG) to Europe and could potentially export by pipeline to China. FSU has subsidized pricing within its own region but has used its market power to insist upon petroleum index pricing for its exports.

The Middle East (primarily Qatar and Iran) has access to vast natural gas resources, which are inexpensive to produce. These resources are more than ample to supply a relatively small but growing demand for natural gas in the Middle East. Since the Middle East is located relatively far from other major natural gas demand regions (Asia and Europe), gas pipeline projects have not materialized, although they have been discussed. LNG represents one attractive means for Qatar to monetize its natural gas resource, and it has become the world's largest LNG producer. However, Qatar has decided to restrain its sales of LNG.

Southeast Asia and Australia are also regions with abundant low cost natural gas resources. They can in the near term (Southeast Asia with its rapid economic growth will require increasing natural gas volumes in the future) accommodate their domestic demand with additional volumes to export. Given the vast distances and the isolation by water, pipeline projects that move natural gas to primary Asian markets are not practical. As a result, LNG is a very attractive mean to monetize their resource.

The combined market of Central and South America is relatively small for natural gas. The region has managed to meet its demand with its own indigenous supplies. It has exported some LNG to European markets. Central and South America has untapped natural gas resources that could result in growing LNG exports.

The North American region has a large natural gas demand but has historically been able to satisfy its demand with indigenous resources. It has a small LNG import/export industry driven by specific niche markets. Thus, it has mostly functioned as a semi-autonomous market, separate from the rest of the world.

2. LNG Trade Patterns

LNG Trading patterns are determined by a number of criteria: short-term demand, availability of supplies, and proximity of supply projects to markets. A significant portion of LNG is traded on a long-term basis using dedicated supplies, transported with dedicated vessels to identified markets. Other LNG cargoes are traded on an open market moving to the highest valued customer. Southeast Asian and Australian suppliers often supply Asian markets, whereas African suppliers most often serve Europe. Because of their relative location, Middle East suppliers can and do ship to both Europe and Asia. Figure 10 lists 2010 LNG shipping totals with the leftmost column representing the exporters and the top row representing the importing regions.

Figure 10: 2010 LNG Trade (Tcf)

From\To	Africa	Canada	China/ India	C&S America	Europe	FSU	Korea/ Japan	Middle East	Oceania	Sakhalin	Southeast Asia	U.S.	**Total Exports**
Africa		0.03	0.05	0.31	1.33		0.24	0.21			0.07	0.31	**2.54**
Canada													**0.00**
China/India													**0.00**
C&S America		0.00		0.01	0.02		0.00					0.01	**0.05**
Europe				0.01	0.11		0.05	0.01			0.00		**0.18**
FSU													**0.00**
Korea/Japan													**0.00**
Middle East		0.01	0.44	0.08	1.15		1.28	0.10			0.15	0.08	**3.29**
Oceania			0.17				0.62				0.04		**0.83**
Sakhalin			0.02				0.39	0.00			0.02		**0.43**
Southeast Asia			0.14	0.06			1.92	0.01			0.21		**2.34**
U.S.							0.03						**0.03**
Total Imports	**0.00**	**0.04**	**0.81**	**0.47**	**2.61**	**0.00**	**4.53**	**0.34**	**0.00**	**0.00**	**0.49**	**0.40**	**9.70**

Source: "The LNG Industry 2010," GIIGNL.

3. Basis Differentials

The basis[10] between two different regional gas market hubs reflects the difference in the pricing mechanism for each regional market. If pricing for both market hubs were set by the same mechanism and there were no constraints in the transportation system, the basis would simply be the cost of transportation between the two market hubs. Different pricing mechanisms, however, set the price in each regional market, so the basis is often not set by transportation differences alone. For example, the basis between natural gas prices in Japan and Europe's natural gas prices reflects the differences in natural gas supply sources for both markets. Japan depends completely upon LNG as it source for natural gas and indexes the LNG price to crude. For Europe, LNG is only one of several potential sources of supply for natural gas, others being interregional pipelines and indigenous natural gas production. The pricing at the National Balancing Point ("NBP") reflects the competition for market share between these three sources. Because of its limited LNG terminals for export or import, North America pricing at Henry Hub has been for the most part set by competition between different North American supply sources of natural gas and has been independent of pricing in Japan and Europe. If the marginal supply source for natural gas in Europe and North America were to become LNG, then the pricing in the two regions would be set by LNG transportation differences.

B. NERA's Global Natural Gas Model

The GNGM is a partial-equilibrium model designed to estimate the amount of natural gas production, consumption, and trade by major world natural gas consuming and/or producing regions. The model maximizes the sum of consumers' and producers' surplus less transportation costs, subject to mass balancing constraints and regasification, liquefaction, and pipeline capacity constraints.

The model divides the world into the 12 regions described above. These regions are largely adapted from the EIA IEO regional definitions, with some modifications to address the LNG-intensive regions. The model's international natural gas consumption and production projections for these regions are based upon the EIA's AEO and IEO 2011 Reference cases.

The supply of natural gas in each region is represented by a constant elasticity of substitution ("CES") supply curve. The demand curve for natural gas has a similar functional form as the supply curve. As with the supply curves, the demand curve in each region is represented by a CES function (Appendix A).

C. N_{ew}ERA Macroeconomic Model

NERA developed the N_{ew}ERA model to forecast the impact of policy, regulatory, and economic factors on the energy sectors and the economy. When evaluating policies that have significant

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10 The basis is the difference in price between two different natural gas market hubs.

impacts on the entire economy, one needs to use a model that captures the effects as they ripple through all sectors of the economy and the associated feedback effects. The version of the N$_{ew}$ERA model used for this analysis includes a macroeconomic model with all sectors of the economy.

The macroeconomic model incorporates all production sectors, including liquefaction plants for LNG exports, and final demand of the economy. The consequences are transmitted throughout the economy as sectors respond until the economy reaches equilibrium. The production and consumption functions employed in the model enable gradual substitution of inputs in response to relative price changes, thus avoiding all-or-nothing solutions.

There are great uncertainties about how the U.S. natural gas market will evolve, and the N$_{ew}$ERA model is designed explicitly to address the key factors affecting future natural gas demand, supply, and prices. One of the major uncertainties is the availability of shale gas in the United States. To account for this uncertainty and the subsequent effect it could have on the domestic markets, the N$_{ew}$ERA model includes resource supply curves for U.S. natural gas. The model also accounts for foreign imports, in particular pipeline imports from Canada, and the potential build-up of liquefaction plants for LNG exports. N$_{ew}$ERA also has a supply (demand) curve for U.S. imports (exports) that represents how the global LNG market price would react to changes in U.S. imports or exports. On a practical level, there are also other important uncertainties about the ownership of LNG plants and how the LNG contracts will be formulated. These have important consequences on how much revenue can be earned by the U.S. and hence overall macroeconomic impacts. In the N$_{ew}$ERA model it is possible to represent these variations in domestic versus foreign ownership of assets and capture of export revenues to better understand the issues.

U.S. wellhead natural gas prices are not precisely the same in the GNGM and the U.S. N$_{ew}$ERA model. Supply curves in both models were calibrated to the EIA implicit supply curves, but the GNGM has a more simplified representation of U.S. natural gas supply and demand than the more detailed N$_{ew}$ERA model so that the two models solve for slightly different prices with the same levels of LNG exports. The differences are not material to any of the results in the study.

The N$_{ew}$ERA model includes other energy markets. In particular, it represents the domestic and international crude oil and refined petroleum markets.

We balance the international trade account in the N$_{ew}$ERA model by constraining changes in the current account deficit over the model horizon. The condition is that the net present value of the foreign indebtedness over the model horizon remains at the benchmark year level. This prevents distortions in economic effects that would result from perpetual increase in borrowing, but does not overly constrain the model by requiring current account balance in each year.

This treatment of the current account deficit does not mean that there cannot be trade benefits from LNG exports. Although trade will be in balance over time, the terms of trade shift in favor of the U.S. because of LNG exports. That is, by exporting goods of greater value to overseas customers, the U.S. is able to import larger quantities of goods than it would able to if the same domestic resources were devoted to producing exports of lesser value. Allowing high value exports to proceed has a similar effect on terms of trade as would an increase in the world price of existing exports or an increase in productivity in export industries. In all these cases, the U.S. gains more imported goods in exchange for the same amount of effort being devoted to production of goods for export. The opposite is also possible, in that a drop in the world price of U.S. exports or a subsidy that promoted exports of lesser value would move terms of trade against the U.S., in that with the same effort put into producing exports the U.S. would receive less imports in exchange and terms of trade would move against the U.S. The fact that LNG will be exported only if there is sufficient market demand ensures that terms of trade will improve if LNG exports take place.

The N_{ew}ERA model outputs include demand and supply of all goods and services, prices of all commodities, and terms of trade effects (including changes in imports and exports). The model outputs also include gross regional product, consumption, investment, disposable income and changes in income from labor, capital, and resources.

IV. DESCRIPTION OF SCENARIOS

EIA's analysis combined assumptions about levels of natural gas exports with assumptions about uncertain factors that will drive U.S. natural gas supply and demand to create 16 scenarios. EIA's analysis did not and was not intended to address the question of whether these quantities could be sold into world markets under the conditions assumed in each scenario. Since global demand for LNG exports from the United States also depends on a number of uncertain factors, NERA designed scenarios for global supply and demand to capture those uncertainties. The global scenarios were based on different sets of assumptions about natural gas supply and demand outside the United States. The combination of assumptions about maximum permitted levels of exports, U.S. supply and demand conditions, and global supply and demand conditions yielded 63 distinct scenarios to be considered.

The full range of scenarios that we considered included the different combinations of international supply and demand, availability of domestic natural gas, and LNG export capabilities. The remainder of this section discusses this range of scenarios.

A. How Worldwide Scenarios and U.S. Scenarios Were Designed

1. World Outlooks

The International scenarios were designed to examine the role of U.S. LNG in the world market (Figure 11). Before determining the macroeconomic impacts in the U.S., one must know the circumstances under which U.S. LNG would be absorbed into the world market, the level of exports that would be economic on the world market and the value (netback) of exported LNG in the U.S. In order to accomplish this, several International scenarios were developed that allowed for growing worldwide demand for natural gas and an increasing market for LNG. These were of more interest to this study because the alternative of lower worldwide demand would mean little or no U.S. LNG exports, which would have little or no impact on the U.S. economy.

Figure 11: International Scenarios

Case Name	Japan Nuclear Plants Retired	Korean Nuclear Plants Retired	Planned Liquefaction Capacity in Other Regions Is Built
International Reference	No	No	Yes
Demand Shock	Yes	No	Yes
Supply/Demand Shock	Yes	Yes	No

a. International Reference Case: A Plausible Baseline Forecast of Future Global Demand and Supply

The International Reference case is intended to provide a plausible baseline forecast for global natural gas demand, supply, and prices from today through the year 2035. The supply and demand volumes are based upon EIA IEO 2011 with countries aggregated to the regions in the NERA Global Natural Gas Model. The regional natural gas pricing is intended to model the pricing mechanisms in force in the regions today and their expected evolution in the future. Data to develop these pricing forecasts were derived from both the EIA and the International Energy Agency's World Energy Outlook 2011 ("IEA WEO").

Our specific assumptions for the global cases are described in Appendix A.

b. Uncertainties about Global Natural Gas Demand and Supply

To reflect some of the uncertainty in demand for U.S. LNG exports, we analyzed additional scenarios that potentially increased U.S. LNG exports. Increasing rather than decreasing exports is of more interest in this study because it is the greater level of LNG exports that would result in larger impact on the U.S. economy. The two additional International scenarios increase either world demand alone or increase world demand while simultaneously constraining the development of some new LNG supply sources outside the U.S. Both scenarios would result in a greater opportunity for U.S. LNG to be sold in the world market.

- The first additional scenario ("Demand Shock") creates an example of increased demand by assuming that Japan converts all its nuclear power generation to natural gas-fired generation. This scenario creates additional demand for LNG in the already tight Asian market. Because Japan lacks domestic natural gas resources, the incremental demand could only be served by additional LNG volumes.

- The second scenario ("Supply/Demand Shock") is intended to test a boundary limit on the international market for U.S. LNG exports. This scenario assumes that both Japan and Korea convert their nuclear demand to natural gas and on the supply side it is assumed that no new liquefaction projects that are currently in the planning stages will be built in Oceania, Southeast Asia, or Africa. The precise quantitative shifts assumed in world supply and demand are described in Appendix A.

Neither of these scenarios is intended to be a prediction of the future. Their apparent precision (Asian market) is only there because differential transportation costs make it necessary to be specific about where non-U.S. demand and supply are located in order to assess the potential demand for U.S. natural gas. Many other, and possibly more likely, scenarios could be constructed, and some would lead to higher and others to lower exports. The scenarios that we modeled are intended as only one possible illustration of conditions that could create higher demand for U.S. LNG exports.

2. U.S. Scenarios Address Three Factors

a. Decisions about the Upper Limit on Exports

One of the primary purposes of this study is to evaluate the impacts of different levels of natural gas exports. The levels of exports that are used in constructing the U.S. scenarios are the four levels specified by the DOE/FE as part of EIA's Study. In addition, the DOE requested that we add one additional level of exports, "Slowest," to address additional uncertainties about how rapidly liquefaction capacity could be built that were not captured by the EIA analysis. Lastly, we evaluated a No-Export constraint scenario, whereby we could determine the maximum quantity of exports that would be demanded based purely on the economics of the natural gas market and a No-Export capacity scenario to provide a point of comparison for impacts of LNG exports.

b. Uncertainties about U.S. Natural Gas Demand and Supply

The advances in drilling technology that created the current shale gas boom are still sufficiently recent that there remains significant uncertainty as to the long-term natural gas supply outlook for the U.S. In addition to the uncertain geological resource, there are also other uncertainties such as how much it will cost to extract the natural gas, and many regulatory uncertainties including concerns about seismic activity, and impacts on water supplies that may lead to limits on shale gas development.

On the demand side there has been a considerable shift to natural gas in the electric sector in recent years as a result of the low natural gas prices. Looking into the future, there are expected to be many retirements of existing coal-fired generators as a result of the low natural gas prices and new EPA regulations encouraging natural gas use. As a result, most new baseload capacity being added today is fueled with natural gas. Industrial demand for natural gas is also tied to price levels. The current low prices have increased projected outputs from some natural gas-intensive industries like chemicals manufacturing. The shift toward natural gas could be accelerated by pending and possible future air, water, and waste regulations and climate change policies. Thus, the potential exists for significant increases in natural gas demand across the U.S. economy.

Combining uncertainties about the U.S. outlooks for natural gas supply and demand results in a wide range of projections for the prices, at which natural gas may be available for export.

To reflect this uncertainty, the EIA, in its AEO 2011, included several sensitivity cases in addition to its Reference Case. For natural gas supply, the two most significant are the Low Shale EUR and High Shale EUR sensitivity cases. We also adopt these cases, in addition to the Reference Case supply conditions, in evaluating the potential for exports of natural gas.

B. Matrix of U.S. Scenarios

The full range of potential U.S. scenarios was constructed based on two factors: 1) U.S. supply and 2) LNG export quotas. There are three different U.S. supply outlooks:[11]

1. Reference ("USREF"): the AEO 2011 Reference case;

2. High Shale Estimated Ultimate Recovery ("HEUR") case: reflecting more optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent higher than in the Reference case; and

3. Low Shale EUR case ("LEUR"): reflecting less optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent lower than in the Reference case.[12]

As for the LNG export quotas, we considered six different LNG export quota trajectories, all starting in 2015:

1. Low/Slow ("LS"): 6 Bcf/d, phased in at a rate of 1 Bcf/d per year;

2. Low/Rapid ("LR"): 6 Bcf/d phased in at a rate of 3 Bcf/d per year;

3. High/Slow ("HS"): 12 Bcf/d phased in at a rate of 1 Bcf/d per year;

4. High/Rapid ("HR"): 12 Bcf/d phased in at a rate of 3 Bcf/d per year;

5. Low/Slowest ("LSS"): 6 Bcf/d phased in at a rate of 0.5 Bcf/d per year; and

6. No-Export Constraint: No limits on U.S. LNG export capacity were set and therefore our Global Natural Gas Model determined exports entirely based on the relative economics.

The combination of these two factors results in the matrix of 18 (3 supply forecasts for each of 6 export quota trajectories) potential U.S. scenarios in Figure 12.

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[11] We eliminate a fourth case, High Demand, run by EIA because the range of demand uncertainty is expected to be within the range spanned by the three cases.

[12] While the statement of work also described a supply outlook using EIA's High Economic Growth case, we found that the results would have been identical to those in the Reference case, and thus, we did not separately analyze that case.

Figure 12: Matrix of U.S. Scenarios

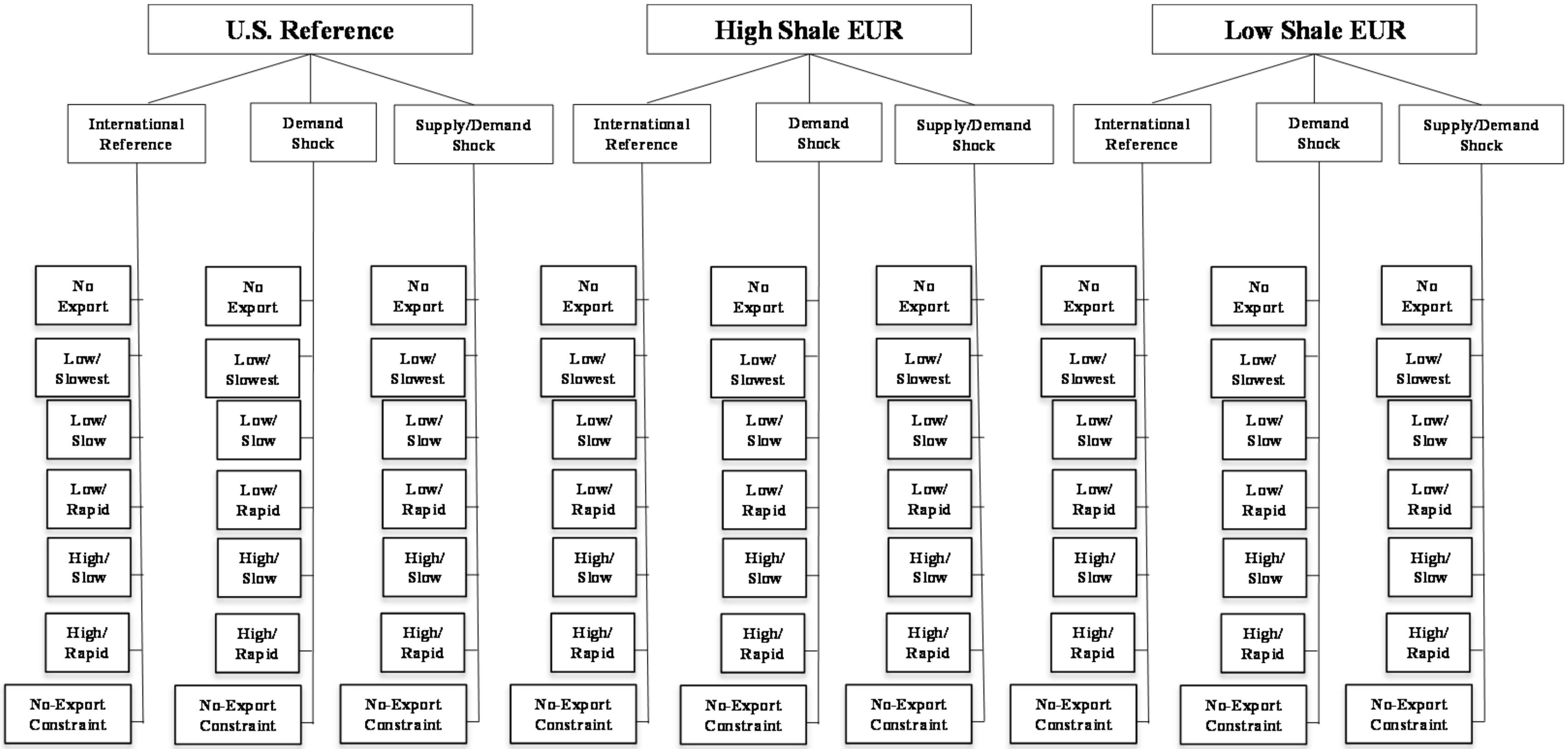
U.S. Supply	LNG Export Capacity	U.S. Supply	LNG Export Capacity	U.S. Supply	LNG Export Capacity
Reference	Low/Slow	High EUR	Low/Slow	Low EUR	Low/Slow
Reference	Low/Rapid	High EUR	Low/Rapid	Low EUR	Low/Rapid
Reference	High/Slow	High EUR	High/Slow	Low EUR	High/Slow
Reference	High/Rapid	High EUR	High/Rapid	Low EUR	High/Rapid
Reference	Low/Slowest	High EUR	Low/Slowest	Low EUR	Low/Slowest
Reference	Unlimited	High EUR	Unlimited	Low EUR	Unlimited

In addition, we created a "No-Export Capacity" scenario for each of the three U.S. supply cases.

C. Matrix of Worldwide Natural Gas Scenarios

NERA used its Global Natural Gas Model to analyze international impacts resulting from potential U.S. LNG exports. As shown in Figure 13, a matrix of scenarios combining the three worldwide scenarios with three U.S. supply scenarios and the seven rates of U.S. LNG capacity expansion resulted in a total of 63 different scenarios that were analyzed.

Figure 13: Tree of All 63 Scenarios



V. GLOBAL NATURAL GAS MODEL RESULTS

A. NERA Worldwide Supply and Demand Baseline

NERA's Baseline is based upon EIA's projected production and demand volumes from its 2011 IEO and AEO Reference cases with some modifications.

To develop a worldwide supply and consumption baseline, we first adjusted the IEO's estimates for production and consumption in the ten non-North American regions. Then we adjusted the IEO projections for two North American regions. For the ten non-North American regions, we computed the average of the IEO's estimate for worldwide production and demand excluding North American production, consumption and LNG imports. Then, we scaled the production in each of these ten regions individually by the ratio of this average and the original production in these ten regions. We used a similar methodology for determining demand in these ten regions.

Next, we calibrated both the U.S. imports from Canada and U.S. LNG imports. U.S. pipeline imports from Canada varied for each of the three U.S. supply cases: AEO reference, High Shale EUR, and Low Shale EUR. U.S. LNG imports were next calculated as the difference between total U.S. imports less pipeline imports. This calculation was repeated for each U.S. supply case. The calculated LNG imports are consistent with the official AEO numbers.

For LNG exporting regions, we checked that they had sufficient liquefaction capacity so that their calibrated production was less than or equal to their demand plus their liquefaction and inter-regional pipeline capacity. If not, we adjusted the region's liquefaction capacity so that this condition held with equality. For the Middle East, we imposed a limit on the level of 4.64 Tcf on its LNG exports. Since its liquefaction capacity exceeds its export limit, the Middle East supply must be less than or equal to its demand plus its LNG export limit. If this condition failed to hold, we adjusted Middle East supply until Middle East supply equaled its demand plus its LNG export limit.

In calibrating the FSU, NERA assumes that the recalibrated (as per the above adjustment made to the IEO data) production is correct and any oversupply created by the calibration of supply and demand is exported by pipeline.

For LNG importing regions, we checked to determine if, after performing the recalibration described above, the demand in each importing region was less than the sum of their domestic natural gas production, regasification capacity, and inter-regional pipeline capacity. In each region where this condition failed, we expanded its regasification capacity until this condition held with equality. Figure 14 reports the resulting natural gas productions to which we calibrated each region in our GNGM. Figure 15 reports the resulting natural gas demand to which we calibrated each region in our GNGM.

Figure 14: Baseline Natural Gas Production (Tcf)

	2010	2015	2020	2025	2030	2035
Africa	7.80	9.70	11.10	12.20	13.30	14.10
Canada	6.10	7.00	7.70	8.30	8.70	9.00
China/India	4.60	5.60	6.70	8.00	9.60	9.70
C&S America	6.80	7.90	8.30	9.20	10.50	11.70
Europe	9.50	8.10	7.40	7.50	7.90	8.30
FSU	28.87	30.05	32.12	34.89	37.77	39.94
Korea/Japan	0.20	0.20	0.20	0.20	0.20	0.20
Middle East	16.30	19.70	22.40	24.60	26.70	28.80
Oceania	2.10	2.60	3.10	3.80	4.80	5.70
Sakhalin	0.43	0.45	0.48	0.51	0.53	0.56
Southeast Asia	9.30	10.00	10.70	11.60	12.60	13.40
U.S.	21.10	22.40	23.40	24.00	25.10	26.40
World	113.10	123.70	133.60	144.80	157.70	167.80

Figure 15: Baseline Natural Gas Demand (Tcf)

	2010	2015	2020	2025	2030	2035
Africa	3.90	4.70	5.90	7.10	8.30	9.10
Canada	3.30	3.50	3.70	4.20	4.60	5.00
China/India	5.70	8.60	10.70	13.10	15.10	16.60
C&S America	6.60	7.40	8.90	10.50	12.20	14.40
Europe	19.20	19.80	20.40	20.90	22.00	23.20
FSU	24.30	24.30	24.50	24.90	25.80	26.50
Korea/Japan	5.00	5.20	5.30	5.70	5.90	5.90
Middle East	12.50	14.70	17.00	19.10	21.30	24.00
Oceania	1.20	1.30	1.50	1.80	2.00	2.20
Sakhalin	0.00	0.00	0.00	0.00	0.00	0.00
Southeast Asia	7.40	8.50	10.00	12.00	13.90	15.30
U.S.	23.80	25.10	25.30	25.10	25.90	26.50
World	112.90	123.10	133.20	144.40	157.00	168.70

NERA developed a set of world natural gas price projections based upon a number of data sources. The approach focuses on the wellhead price forecasts for net export regions and city gate price forecasts for net import regions.

U.S. wellhead natural gas prices are not precisely the same in the global natural gas model and the U.S. N_{ew}ERA model. Supply curves in both models were calibrated to the EIA implicit supply curves, but the GNGM has a more simplified representation of U.S. natural gas supply and demand than the more detailed N_{ew}ERA model so that the two models solve for slightly different prices with the same levels of LNG exports. The differences are not material to any of the results in the study.

In natural gas-abundant regions like the Middle East and Africa, the wellhead price is assumed to equal the natural gas development and lifting cost. City gate prices are estimated by adding a transportation cost to the wellhead prices. In the major Asian demand markets, natural gas prices are determined on a near oil-parity basis using crude oil price forecasts from IEA's WEO 2011. The resultant prices are highly consistent with the relevant historical pipeline import prices13 and LNG spot market prices as well as various oil and natural gas indices (*i.e.*, JCC, WTI, Henry Hub, AECO Hub indices, and UK National Balancing Point). U.S. wellhead and average city gate prices are adopted from AEO 2012 Early Release. Canadian wellhead prices are projected to initially be $0.35 less than the U.S. prices in the Reference case. The resulting city gate and wellhead prices are presented in Figure 16 and Figure 17.

[13] German BAFA natural gas import border price, Belgium Zeebrugge spot prices, TTF Natural Gas Futures contracts, *etc*.

Figure 16: Projected Wellhead Prices (2010$/MMBtu)

	2010	2015	2020	2025	2030	2035
Africa	$1.75	$1.89	$2.09	$2.31	$2.55	$2.81
Canada	$3.39	$3.72	$4.25	$5.20	$5.64	$6.68
China/India	$12.29	$12.86	$13.00	$13.25	$13.57	$13.51
C&S America	$2.00	$2.16	$2.39	$2.64	$2.91	$3.22
Europe	$9.04	$9.97	$10.80	$11.95	$12.39	$13.23
FSU	$4.25	$4.60	$5.08	$5.61	$6.19	$6.84
Korea/Japan	$14.59	$15.30	$15.47	$15.79	$16.19	$16.11
Middle East	$1.25	$1.35	$1.49	$1.65	$1.82	$2.01
Oceania	$1.75	$1.89	$2.09	$2.31	$2.55	$2.81
Sakhalin	$1.25	$1.35	$1.49	$1.65	$1.82	$2.01
Southeast Asia	$2.00	$2.16	$2.39	$2.64	$2.91	$3.22
U.S.	$3.72	$3.83	$4.28	$5.10	$5.48	$6.36

Figure 17: Projected City Gate Prices (2010$/MMBtu)

	2010	2015	2020	2025	2030	2035
Africa	$2.75	$2.89	$3.09	$3.31	$3.55	$3.81
Canada	$4.79	$5.12	$5.65	$6.60	$7.04	$8.08
China/India	$13.79	$14.36	$14.50	$14.75	$15.07	$15.01
C&S America	$4.50	$4.66	$4.89	$5.14	$5.41	$5.72
Europe	$10.04	$10.97	$11.80	$12.95	$13.39	$14.23
FSU	$5.25	$5.60	$6.08	$6.61	$7.19	$7.84
Korea/Japan	$15.09	$15.80	$15.97	$16.29	$16.69	$16.61
Middle East	$4.08	$4.18	$4.32	$4.48	$4.65	$4.84
Oceania	$3.25	$3.39	$3.59	$3.81	$4.05	$4.31
Sakhalin	$3.75	$3.85	$3.99	$4.15	$4.32	$4.51
Southeast Asia	$3.00	$3.16	$3.39	$3.64	$3.91	$4.22
U.S.	$4.72	$4.83	$5.28	$6.10	$6.48	$7.36

After calibrating the GNGM to the above prices and quantities, we allowed the model to solve for the least-cost method of transporting gas so that supplies and demands are met. Figure 18,

Figure 19, and Figure 20 display the pipeline flows between model regions, LNG exports, and LNG imports for all model years in the baseline.

Figure 18: Baseline Inter-Region Pipeline Flows (Tcf)

Origin	Destination	2010	2015	2020	2025	2030	2035
Africa	Europe	1.53	1.68	1.41	0.94	0.88	0.87
Canada	U.S.	2.33	2.33	1.40	0.74	0.64	0.04
FSU	China/India	0.07	0.34	1.18	1.55	1.59	1.83
FSU	Europe	4.55	5.88	7.21	9.22	10.38	10.84

Figure 19: Baseline LNG Exports (Tcf)

Exporter	2010	2015	2020	2025	2030	2035
Africa	2.38	3.46	4.02	4.45	4.12	3.77
C&S America	0.37	0.66	0.50	0.19	0.16	0.06
Sakhalin	0.44	0.48	0.49	0.52	0.55	0.59
Middle East	4.10	4.64	4.64	4.64	4.64	4.64
Oceania	0.74	1.28	1.63	2.02	2.60	3.04
Southeast Asia	1.64	1.42	0.85	-	-	-

Figure 20: Baseline LNG Imports (Tcf)

Importer	2010	2015	2020	2025	2030	2035
China/India	1.02	2.58	2.52	3.21	3.69	3.48
Europe	3.58	3.99	4.02	2.82	2.57	2.98
Korea/Japan	4.80	5.00	5.05	5.21	5.43	5.48
U.S.	0.37	0.37	0.50	0.36	0.16	0.06

B. Behavior of Market Participants

In a market in which existing suppliers are collecting profits, the potential entry of a new supplier creates an issue concerning how the existing suppliers should respond. Existing suppliers have three general strategy options:

1. Existing suppliers can voluntarily reduce their own production, conceding market share to the new entrant in order to maintain market prices.

2. Existing suppliers can act as price takers, adjusting their volume of sales until prices reach a new, lower equilibrium.

3. Existing suppliers can choose to produce at previously planned levels with the hope of discouraging the new potential supplier from entering the market by driving prices below levels acceptable to the new entrant.

How much the U.S. will be able to export, and at what price, depends critically on how other LNG producers like Qatar that are low cost producers but currently limiting exports would react to the appearance of a new competitor in the market. Our model of the world gas market is one of a single dominant supplier, which has the largest shares of LNG exports and is thought to be limiting output, and a competitive fringe whose production adjusts to market prices.[14] Our calculation of U.S. benefits from trade assumes that the dominant supplier would not change its plans for expanding production to counter U.S. entry into the market (strategy 3). Their continued production would leave no room for U.S. exports until prices were driven down far enough to stimulate sufficient additional demand to absorb economic exports from the U.S. Since the competitive fringe does reduce output (strategy 2) as prices fall due to U.S. LNG exports, there is an opportunity for the U.S. to enter the market but only by driving delivered LNG prices in key markets below what they are today. Should these countries respond instead by cutting production below planned levels to maintain prices, the U.S. could gain greater benefits and a larger market share. If the dominant supplier chooses to cut prices, then exporting LNG from the U.S. would become less attractive to investors.

Another consideration is the behavior of LNG consumers. At this point in time, countries like Japan and Korea appear to be paying a substantial premium over the price required to obtain supplies from regions that have not imposed limits on planned export capacity. At the same time, those countries are clearly looking into arrangements in the United States that would provide natural gas at a delivered cost substantially below prices they currently pay for LNG deliveries. This could be because they view the U.S. as a uniquely secure source of supply, or it could be that current high prices reported for imports into Japan and Korea are for contracts that will expire and be replaced by more competitively priced supplies. If countries like Japan and Korea became convinced that they could obtain secure supplies without long-term oil-based pricing contracts, and ceased paying a premium over marginal cost, the entire price structure could shift downward. Since the U.S. does not appear to be the world's lowest cost supplier, this could have serious consequences for the profitability of U.S. exports.

In this study, we address issues of exporter responses by assuming that there is a competitive market with exogenously determined export limits chosen by each exporting region and determined by their liquefaction capacity. This assumption allows us to explore different scenarios for supply from the rest of the world when the U.S. begins to export. This is a middle

[14] We consider the dominant supplier to be Qatar, with a 31% share of the market in 2011, while also exercising some production restraint.

ground between assuming that the dominant producer will limit exports sufficiently to maintain the current premium apparent in the prices paid in regions like Japan and Korea, or that dominant exporters will remove production constraints because with U.S. entry their market shares fall to levels that do not justify propping up prices for the entire market.

It is outside the scope of this study to analyze alternative responses by other LNG suppliers in order to determine what would be in their best economic interest or how they might behave strategically to maximize their gains. This would require a different kind of model that addresses imperfect competition in global LNG markets and could explain the apparent ability of some large exporters to set prices for some importing countries at prices higher than the cost of production plus transportation.

C. Available LNG Liquefaction and Shipping Capacity

This analysis did not investigate the technical feasibility of building new liquefaction capacity in a timely fashion to support the level of exports the model found optimal. In all cases, the GNGM assumed no limits on either LNG liquefaction capacity additions outside the U.S. or world LNG shipping capacity. The only LNG export capacity limits were placed on the U.S. and the Middle East.

D. The Effects of U.S. LNG Exports on Regional Natural Gas Markets

When the U.S. exports LNG, the worldwide and domestic natural gas markets are affected in the following ways:

- The additional supplies from U.S. LNG exports cause a drop in city gate prices in the importing regions;
- The lower prices lead to increased natural gas consumption in the importing regions;
- Relative to the baseline forecast, U.S. LNG exports displace some LNG exports from other regions, which leads to lower production levels in many of the other exporting regions;
- U.S. LNG exports displace FSU pipeline exports to Europe and China, which leads to lower FSU production;
- Exporting regions with lower LNG or pipeline exports and hence lower production levels experience a drop in wellhead and city gate prices because of the lower demand for their gas;
- Natural gas production rises in the U.S. because there is additional demand for its gas;

- Wellhead natural gas prices rise in the U.S. because of the increased demand, which leads to higher city gate prices; and

- Higher U.S. prices cause a reduction in U.S. natural gas consumption.

Whether or not a region's exports would be displaced by U.S. LNG exports depend on several factors:

- The difference in delivered costs between an exporting region and the U.S.;

- The magnitude of the demand shock or increased demand; and

- The magnitude of the supply shock or reduction in world supply.

Because Africa and the Middle East are the lowest cost producers, U.S. LNG exports have the smallest effect on their exports. Also, the Middle East's exports are limited by our assumption that Qatar continues to limit its exports of natural gas at its announced levels. Thus, there are pent-up LNG exports, which mean that the Middle East can still export its same level of LNG even with a decline in international gas prices.

Since the cost of exports is higher in some other regions, they are more vulnerable to having their exports displaced by U.S. LNG exports. In the International Reference case, U.S. LNG exports displace LNG exports from all regions to some extent in many of the years. U.S. exports also cause reductions in inter-regional pipeline exports: FSU to Europe and China, as well as Africa to Europe.

In comparing the International Reference case to the Demand Shock and Supply/Demand Shock cases, we find that global LNG exports increase because the world demand for natural gas is greater. Like other regions, U.S. LNG exports increase, which means that they displace a greater number of exports. However, those regions that have some of their exports displaced still export more natural gas under the Demand Shock and Supply/Demand Shock scenarios than under the equivalent International Reference scenarios.

In the Supply/Demand Shock scenarios, Oceania, Southeast Asia, and Africa have their LNG exports restricted. This restriction leads to these regions receiving a netback price in excess of their wellhead prices. Thus, these regions have a margin that buffers them when the U.S. LNG exports try to enter the market. These regions can lower their export price for LNG some while still ensuring their netback price is greater than or equal to their wellhead price and maintain their level of LNG exports at the level that existed before the U.S. entered the market. However, Southeast Asia has a much smaller buffer than Oceania and Africa so when the U.S. enters the market it effectively displaces much of Southeast Asia's supply.

By 2030, demand for LNG becomes greater so low-cost producing regions such as Sakhalin and the Middle East experience no decline in LNG exports when the U.S. LNG exports enter the market.

When the U.S. enters the global LNG market, each region's supply, demand, wellhead price, and city gate price for natural gas respond as expected. More precisely, importing regions increase their demand for natural gas, and exporting regions either reduce or maintain their supply of natural gas. The wellhead and city gate prices for natural gas decline in all importing regions and remain the same in exporting regions except for in the U.S. and Canada, which are now able to export LNG.

E. Under What Conditions Would the U.S. Export LNG?

In order to understand the economic impacts on the U.S. resulting from LNG exports, it is necessary to understand the circumstances under which U.S. natural gas producers will find it profitable to export LNG. To accomplish this, we used GNGM to run a series of scenarios for all combinations of the three U.S. scenarios (Reference, High Shale EUR, and Low Shale EUR) and three international scenarios (International Reference, Demand Shock, and Supply/Demand Shock). In these runs, we varied the constraints on LNG export levels across seven settings (No-Exports, Low/Slowest, Low/Slow, Low/Rapid, High/Slow, High/Rapid, and Unconstrained). Based upon these 63 runs, we found the following:

- For the scenarios which combined the International Reference and U.S. Reference cases, there were no U.S. LNG exports. In part, this is due to the fact that the EIA scenarios upon which they are based assume that global natural gas demand is met by global supplies without U.S. LNG exports. This outcome also implies that U.S. LNG exports under a U.S. Reference scenario would not be lower cost than existing or planned sources of LNG in other regions of the world and thus do not displace them.
- When there is additional growth in global natural gas demand beyond that of the International Reference scenario, then the U.S. exports LNG to help meet this incremental demand. The degree to which the U.S. exports LNG depends upon the abundance and quality of the U.S. resource base.
- When the U.S. gas supplies are more abundant and lower cost than in the U.S. Reference case, the U.S. can competitively export LNG either to meet incremental global demand or to displace planned LNG supplies in other regions.
- Should the U.S. shale gas resource prove less abundant or cost effective, then U.S. LNG exports will be minimal under the most optimistic global scenario (Supply/Demand Shock).

In the next sections, we present the modeling results for each of the three U.S. cases that served as the basis for arriving at these conclusions.

1. Findings for the U.S. Reference Scenario

This section reports the level of U.S. LNG exports under the 21 scenarios (includes no LNG export scenario) that assume the U.S. Reference scenario. These scenarios consider different international assumptions about international demand and supply of natural gas as well as different assumptions about the U.S.'s ability to export LNG. Figure 21 reports the U.S.'s maximum export capacity for each LNG export capacity scenario.

Figure 21: U.S. LNG Export Capacity Limits (Tcf)

LNG Export Capacity Scenarios	2015	2020	2025	2030	2035
Low/Slowest	0.18	1.10	2.01	2.19	2.19
Low/Slow	0.37	2.19	2.19	2.19	2.19
Low/Rapid	1.10	2.19	2.19	2.19	2.19
High/Slow	0.37	2.19	4.02	4.38	4.38
High/Rapid	1.10	4.38	4.38	4.38	4.38
No Constraint	N/A	N/A	N/A	N/A	N/A

Figure 22 reports the level of U.S. LNG exports. Viewing Figure 21and Figure 22, one can see the effect of the LNG export capacity limits on restraining U.S. exports and the effect of these limits under different assumptions about the International scenarios.

Figure 22: U.S. LNG Exports –U.S. Reference (Tcf)

Bold numbers indicate that the U.S. LNG export limit is binding

U.S. Scenario	International Scenario	LNG Export Capacity Scenarios	2015	2020	2025	2030	2035
U.S. Reference	Demand Shock	Low/Slowest	**0.18**	0.98	1.43	1.19	1.37
		Low/Slow	**0.37**	0.98	1.43	1.19	1.37
		Low/Rapid	1.02	0.98	1.43	1.19	1.37
		High/Slow	**0.37**	0.98	1.43	1.19	1.37
		High/Rapid	1.02	0.98	1.43	1.19	1.37
		No Constraint	1.02	0.98	1.43	1.19	1.37
	Supply/ Demand Shock	Low/Slowest	**0.18**	**1.10**	**2.01**	**2.19**	**2.19**
		Low/Slow	**0.37**	**2.19**	**2.19**	**2.19**	**2.19**
		Low/Rapid	**1.10**	**2.19**	**2.19**	**2.19**	**2.19**
		High/Slow	**0.37**	**2.19**	3.93	**4.38**	**4.38**
		High/Rapid	**1.10**	2.92	3.93	**4.38**	**4.38**
		No Constraint	2.17	2.92	3.93	4.54	5.75

Figure 22 omits the International Reference Scenario because when there are no international shocks that either raise world demand or lower world supply from baseline levels, then the U.S. does not export LNG. However, the U.S. does export LNG when higher levels of world demand are assumed and exports even greater amounts of LNG when both world demand increases and non-U.S. supply planned expansions are not built (units denoted as “under construction” are still assumed to be built).

Under the Demand Shock scenario from 2020 onward, the economic level of U.S. LNG exports do not reach export capacity limits. Therefore, the level of exports in the years 2020 through 2035 is the same for all LNG export capacity levels. Under Supply/Demand Shock scenario, however, the LNG export capacity limits are often binding.[15] The low U.S. LNG capacity export limits are binding for all rates of expansion (Low/Slowest, Low/slow, and Low/Rapid) for all years. For the high LNG export levels, some years are binding and some are not. Under the Supply/Demand Shock scenarios, LNG exports are always greater than or equal to LNG exports in the Demand Shock cases.

The U.S. LNG export capacity binds when the optimal level of exports as determined by the model (see the rows denoted “No Constraint”) exceeds the LNG export capacity level. The difference between the value of LNG exports in the “No Constraint” row and a particular case with a LNG export capacity defines the quantity of exports that LNG export capacity prohibits from coming onto the world market. The greater this number, the more binding the LNG export capacity and the more valuable an LNG terminal would be. In 2025 for example, the U.S. would choose to export almost 4 Tcf of LNG, but if its export capacity limit followed one of the low level cases (Low/Slowest, Low/Slow, or Low/Rapid), there would be a shortfall of almost 2 Tcf of export capacity. On the other hand, if the export capacity followed one of the high level cases (High/Slow or High/Rapid), the U.S. would have about 0.4 Tcf of spare capacity.

[15] The U.S. LNG export capacity binds when the market equilibrium level of exports as determined by the model exceeds the maximum LNG export capacity assumed in that scenario.

2. Findings for the U.S. High Shale EUR Scenario

Figure 23: U.S. LNG Export – High Shale EUR (Tcf)

Bold numbers indicate that the U.S. LNG export limit is binding

U.S. Scenario	International Scenario	LNG Export Capacity Scenarios	2015	2020	2025	2030	2035
High Shale EUR	International Reference	Low/Slowest	**0.18**	**1.10**	**2.01**	**2.19**	**2.19**
		Low/Slow	**0.37**	**2.19**	**2.19**	**2.19**	**2.19**
		Low/Rapid	**1.10**	**2.19**	**2.19**	**2.19**	**2.19**
		High/Slow	**0.37**	**2.19**	3.77	2.78	3.38
		High/Rapid	**1.10**	2.97	3.77	2.78	3.38
		No Constraint	2.23	2.97	3.77	2.78	3.38
	Demand Shock	Low/Slowest	**0.18**	**1.10**	**2.01**	**2.19**	**2.19**
		Low/Slow	**0.37**	**2.19**	**2.19**	**2.19**	**2.19**
		Low/Rapid	**1.10**	**2.19**	**2.19**	**2.19**	**2.19**
		High/Slow	**0.37**	**2.19**	**4.02**	**4.38**	**4.38**
		High/Rapid	**1.10**	3.94	**4.38**	**4.38**	**4.38**
		No Constraint	3.30	3.94	4.87	4.59	5.61
	Supply/ Demand Shock	Low/Slowest	**0.18**	**1.10**	**2.01**	**2.19**	**2.19**
		Low/Slow	**0.37**	**2.19**	**2.19**	**2.19**	**2.19**
		Low/Rapid	**1.10**	**2.19**	**2.19**	**2.19**	**2.19**
		High/Slow	**0.37**	**2.19**	**4.02**	**4.38**	**4.38**
		High/Rapid	**1.10**	**4.38**	**4.38**	**4.38**	**4.38**
		No Constraint	4.23	5.44	6.72	6.89	8.39

Analogous to Figure 22, Figure 23 shows LNG export levels for the U.S. High Shale EUR scenario and a combination of international and LNG export capacity scenarios. Under this highest level of U.S. natural gas supplies, it is cost-effective to export U.S. LNG with or without any international supply or demand shocks. In 2025, the LNG export capacity is binding in all but two cases: no international shock with either High/Slow or High/Rapid LNG export capacity limits. For all other scenarios, the export levels reflect the different U.S. LNG export capacity levels. The only exception is in the year 2020 for the High/Rapid scenario. Exports are even greater for the unconstrained cases with Demand Shocks and Supply/Demand Shocks.

The U.S. LNG export capacity limits become increasingly more binding as the international shocks lead to greater demand for U.S. LNG exports. Under the Supply/Demand shocks, the U.S. LNG export capacity limits bind in all years for the High Shale EUR case. By 2025, the capacity limits restrict between 2.3 and 4.5 Tcf of U.S. exports. Even with only a Demand shock, the U.S. LNG export capacity limits bind in all years for all limits except the High/Rapid case in 2020 in which U.S. LNG exports are only 0.4 Tcf below the U.S. LNG export capacity limit (Figure 21 and Figure 23) when the export capacity limit is 4.38 Tcf. Without any international shocks, the U.S. LNG export capacity limits bind in all years for the Low/Slowest, Low/Slow and Low/Rapid cases, and the U.S. LNG export capacity limits are non-binding for the High/Slow and High/Rapid cases after 2025.

3. Findings for the U.S. Low Shale EUR Scenario

Figure 24 shows all combinations of International scenarios and LNG export capacity scenarios in which the U.S. exports LNG for the U.S. Low Shale EUR scenario. With Low Shale EUR, U.S. supplies are more costly, and as a result, there are no U.S. LNG exports in either the International Reference or Demand Shock scenarios. For the Supply/Demand shock scenarios, U.S. LNG export capacity is binding only in some years in some cases.

Figure 24: U.S. LNG Export – Low Shale EUR (Tcf)

Bold numbers indicate that the U.S. LNG export limit is binding

U.S. Scenario	International Scenario	LNG Export Capacity Scenarios	2015	2020	2025	2030	2035
Low Shale EUR	Supply/ Demand Shock	Low/Slowest	0	0.78	0.90	0.27	0.52
		Low/Slow	0	0.78	0.90	0.27	0.52
		Low/Rapid	0	0.78	0.90	0.27	0.52
		High/Slow	0	0.78	0.90	0.27	0.52
		High/Rapid	0	0.78	0.90	0.27	0.52
		No Constraint	0	0.78	0.90	0.27	0.52

4. Netback Pricing and the Conditions for “Rents” or “Profits”

When LNG export capacity constrains exports, rents or profits are generated. These rents or profits are the difference in value between the netback and wellhead price. The netback price is the value of the LNG exports in the consuming market, less the costs incurred with transporting the natural gas from the wellhead to the consuming market. In the case of LNG, these costs consist of: pipeline transportation from the wellhead to the liquefaction plant, liquefaction costs, transportation costs by ship from the liquefaction plant to the regasification plant, regasification costs, and pipeline transportation from the regasification facility to the city gate.

The netback price can be either greater than or equal to the average wellhead price. It cannot be lower otherwise there would be no economic incentive to produce the natural gas. In cases where the U.S. LNG exports are below the LNG export capacity, the netback prices the U.S. receives for its exports equal the U.S. wellhead price. However, when the LNG export capacity binds so that LNG exports equal the LNG export capacity level, the U.S. market becomes disconnected from the world market, and the netback prices that the U.S. receives exceed its wellhead prices. In this event, the difference between the netback price and the wellhead price leads to a positive profit or rent.

5. LNG Exports: Relationship between Price and Volume

Figure 25 indicates the range of LNG exports and U.S. natural gas prices that were estimated across all 63 global scenarios, many of which had zero exports and therefore no price impacts.[16] Based on Figure 25, NERA selected 13 scenarios for detailed U.S. economic analysis. These 13 scenarios spanned the full range of potential impacts and provided discrete points within that range for discussion. In this section, we describe the analysis performed to select the 13 scenarios.

Because each of the 63 scenarios was characterized by both a U.S. and international dimension (as well as different U.S. LNG export capacity), shapes and colors were used to denote the different combinations:

- Shapes are used to differentiate among the different U.S. scenarios: U.S. Reference (diamond), High Shale EUR (triangle), and Low Shale EUR (square); and
- Colors are used to differentiate among the International cases: International Reference (red), Demand Shock (blue), and Supply/Demand Shock (yellow). In some instances, the same level of U.S. LNG exports and wellhead prices existed for multiple International cases. In these instances, the naturally combined color of the multiple cases is used (*e.g.*, a green symbol (combination of blue and yellow) if the Demand Shock and Supply/Demand Shock scenarios yield the same results.

Therefore, each point on Figure 25 conveys the U.S. and International scenarios, which may correspond to multiple LNG export capacity scenarios. For example, the northwest yellow square (0.9 Tcf of exports) corresponds to the High/Slow and High/Rapid LNG export capacity scenarios. In our detailed U.S. analysis, we only need to consider one of the multiple scenarios. Thus, we can greatly reduce the number of scenarios because Figure 25 suggests there are far fewer than 63 unique LNG export levels.

The yellow markers (scenarios that include the International Supply/Demand shock) yield the highest levels of LNG exports and U.S. natural gas prices and form the upper right hand boundary of impacts. The most northeast red, blue, and yellow markers for each shape represent the cases where LNG exports are unconstrained. For the scenarios where the LNG exports are below the export capacity limits, the marker represents multiple scenarios.

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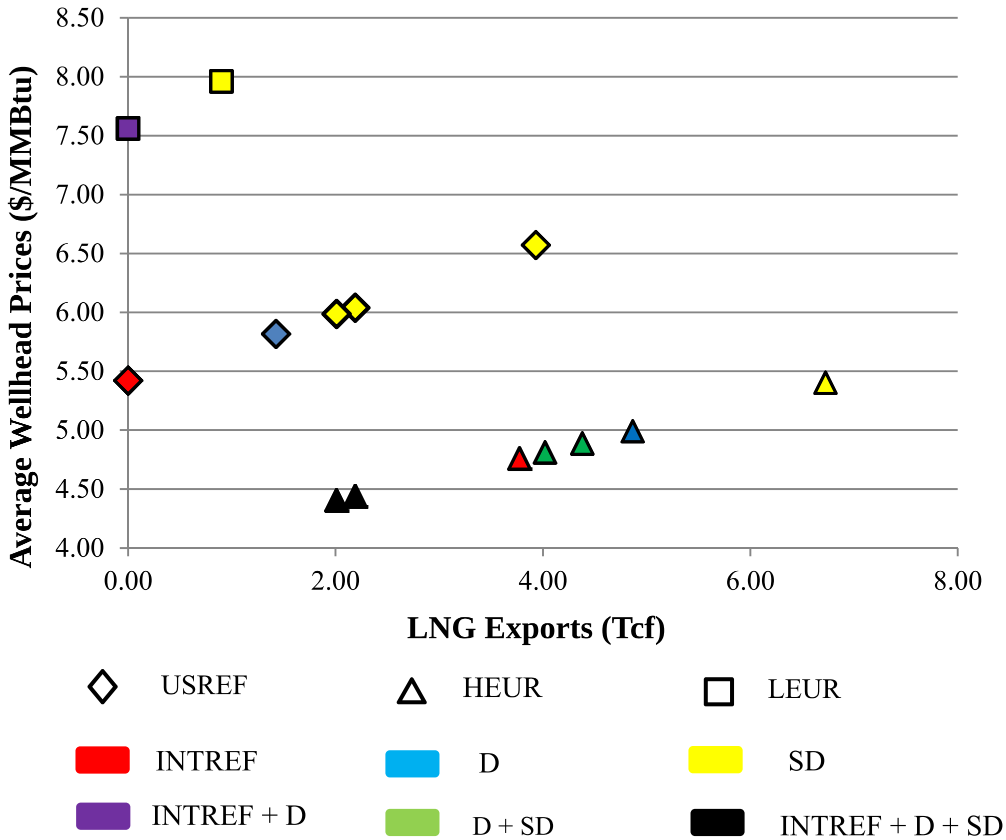
[16] In order to keep the discussion of macroeconomic impacts as concise as possible, this report does not discuss in detail all the scenarios that were run.

Figure 25: U.S. LNG Exports in 2025 Under Different Assumptions
(Note each point can correspond to multiple LNG export capacity scenarios.)



BCF/day = 2.74 * Tcf/Year

The triangles (scenarios that include the High EUR) form a line moving up and to the right, which essentially traces out the U.S. supply curve for LNG under the High EUR scenario. These scenarios combine the lowest U.S. natural gas prices with the highest levels of exports, as would be expected. With High EUR assumptions, U.S. natural gas supply can be increased at relatively low cost enabling larger levels of exports to be economic. For the detailed U.S. economic analysis, we used the High EUR cases to provide the high end of the range for U.S. LNG exports. Since the results are nearly identical between the Demand Shock and Supply and Demand Shock scenarios, we included the five export capacity scenarios under the Supply and Demand Shock because they yielded slightly higher exports.

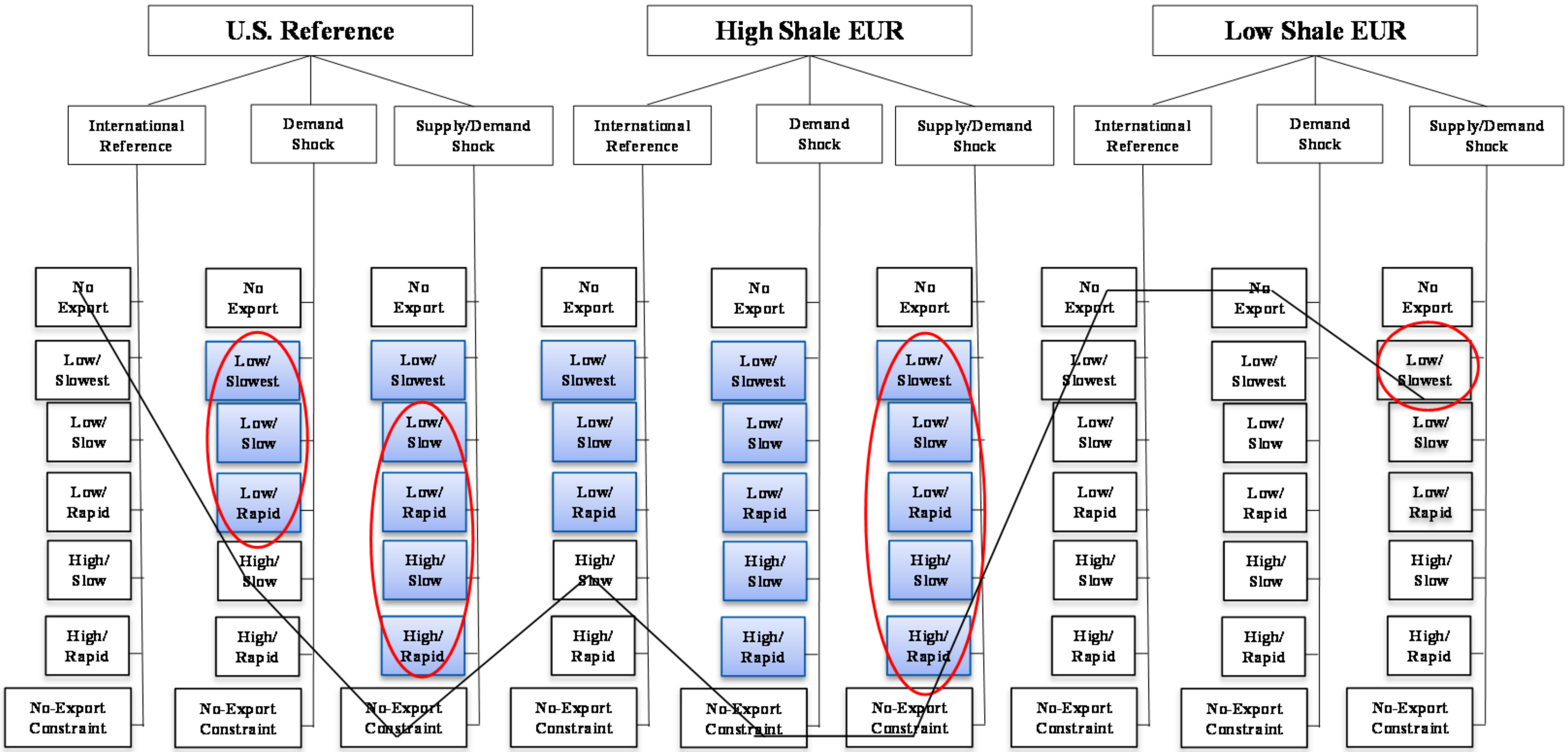
The supply curve traced out by the scenarios that include U.S. Reference case (represented by diamonds) are higher than in the High EUR cases because domestic gas is less plentiful. When only a Demand shock exists, the LNG export capacity limits are non-binding so the level of exports (the lone blue diamond) is the same for all six LNG export capacity scenarios under the U.S. Reference case. Raising the limits on LNG exports in the presence of the International

Demand Shock and Supply/Demand Shock, however, causes actual exports to increase and satisfy more of the higher world demand as exhibited by the series of yellow diamonds that move along a northeast line. In the U.S. Reference case, there are zero exports under International Reference assumptions as represented by the red diamond.

A line joining the squares in Figure 25 traces out the 2025 supply curve for the Low EUR case. The trajectory of the wellhead prices is the highest compared to other cases because of the high underlying baseline wellhead prices. Under the Low EUR baseline, the U.S. wellhead price is $7.56/Mcf in 2025, so that only with International Supply and Demand shocks is there sufficient global demand to bring about positive LNG exports at a price at least as high as the LEUR baseline. The combination of Low EUR and an international supply and demand shock leads to a combination of higher U.S. natural gas prices and lower exports than in the corresponding High EUR or U.S. Reference scenarios. Since exports are similar in the LEUR scenarios in which they exist, we only considered the most binding case (Low EUR with Supply/Demand Shock under the Low/Slowest LNG export capacity), in the detailed U.S. economic analysis. This scenario provides the low end of the export range.

F. Findings and Scenarios Chosen for N_{ew}ERA Model

Figure 26: Scenario Tree with Maximum Feasible Export Levels Highlighted in Blue and N_{ew}Era Scenarios Circled



The first use we made of the GNGM was to determine the level of exports in each of these scenarios that would be accepted by the world market at a price high enough to buy gas at the prevailing wellhead price in the United States, transport it to a liquefaction facility, and liquefy and load it onto a tanker. In some of the above cases, we found that there were no LNG exports because LNG exports would not be profitable. In many cases, we found that the amount of LNG exports that met this profitability test was below the LNG export capacity level assumed in that case. In others, we found that the assumed limit on exports would be binding. In a few cases, we found that the market if allowed would accept more than any of the export limits.

In Figure 26 under the U.S. Reference assumptions as well as in the International Reference case, we found that there would be no export volumes that could be sold profitably into the world market. In the case that combined High Shale EUR and International Reference, it was possible to achieve the Low/Rapid level of exports. After 2010, the exports approach the level of the High/Rapid constraint but never exceed it.

The line in Figure 26 designates the cases in which we observed the maximum level of exports for that combination of U.S. and International assumptions. Export levels and U.S. prices in any case falling below the line were identical to the case identified by the line. Thus, looking down the column for U.S. High EUR supply conditions combined with International Supply/Demand, we found that LNG exports and U.S. wellhead prices were the same with the High/Rapid export limits as with the more constraining High/Slow limits. We therefore did not analyze further any scenarios that fell below the line in Figure 26 and used the No-Export capacity cases to provide a benchmark to which the impacts of increased levels of exports could be compared.

Based on the results of these scenarios, we pared down the scenarios to analyze in the N_{ew}ERA macroeconomic model. Taking into account the possible world natural gas market dynamics, the GNGM model results suggest 21 scenarios in which there were some levels of LNG exports from the U.S. These scenarios were further reduced to 13 scenarios by taking the minimum level of exports across international outlooks. This was done because N_{ew}ERA model does not differentiate various international outlooks. For N_{ew}ERA, the critical issue is the level of U.S. LNG exports and U.S. natural gas production. Of the 13 N_{ew}ERA scenarios (circled in Figure 26), 7 scenarios reflected the U.S. Reference case, 5 reflected the High Shale EUR case with full U.S. LNG export capacity utilization and 1 from the Low EUR case with the lowest export expansion.

VI. U.S. ECONOMIC IMPACTS FROM N_{EW}ERA

A. Organization of the Findings

There are many factors that influence the amount of LNG exports from the U.S. into the world markets. These factors include supply and demand conditions in the world markets and the availability of shale gas in the U.S. The GNGM analysis, discussed in the previous section, found 13 export volume cases under different world gas market dynamics and U.S. natural gas resource outlooks. These cases are implemented as 13 N_{ew}Era scenarios[17] and are grouped as:

- Low/Slow and Low/Rapid DOE/FE export expansion volumes for the Reference natural gas resource outlook referred to as USREF_SD_LS and USREF_SD_LR;

- Low/Slow, Low/Rapid, High/Slow, High/Rapid and Low/Slowest GNGM export expansion volumes for the Reference natural gas resource outlook referred to as USREF_D_LS, USREF_D_LR, USREF_SD_HS, USREF_SD_HR and USREF_D_LSS;

- Low/Slow, Low/Rapid, High/Slow, High/Rapid and Low/Slowest DOE/FE export expansion volumes for the High Shale EUR natural gas resource outlook referred to as HEUR_SD_LS, HEUR_SD_LR, HEUR_SD_HS, HEUR_SD_HR and HEUR_SD_LSS; and

- Low/Slowest GNGM export expansion volumes for the Low Shale EUR natural gas resource outlook referred to as LEUR_SD_LSS

The Reference natural gas outlook scenarios were run against its No-Export volume baseline consistent with AEO 2011 Reference case (Bau_REF). Similarly, the High Shale EUR and Low Shale EUR scenarios were run against its No-Export volume baseline consistent with AEO 2011 High Shale EUR (Bau_HEUR) and AEO 2011 Low Shale EUR (Bau_LEUR) respectively.

This section discusses the impacts on the U.S. natural gas markets and the overall macroeconomic impacts for these 13 scenarios. The impacts are a result of implementing the export expansion scenarios against a baseline without any LNG exports. The economic benefits of the scenarios, as measured by different economic measures, are cross compared. We used economic measures such as welfare, aggregate consumption, disposable income, GDP, and loss of wage income to estimate the impact of the scenarios. The scenario results provide a range of outcomes that capture key sources of uncertainties in the international and the U.S. natural gas markets.

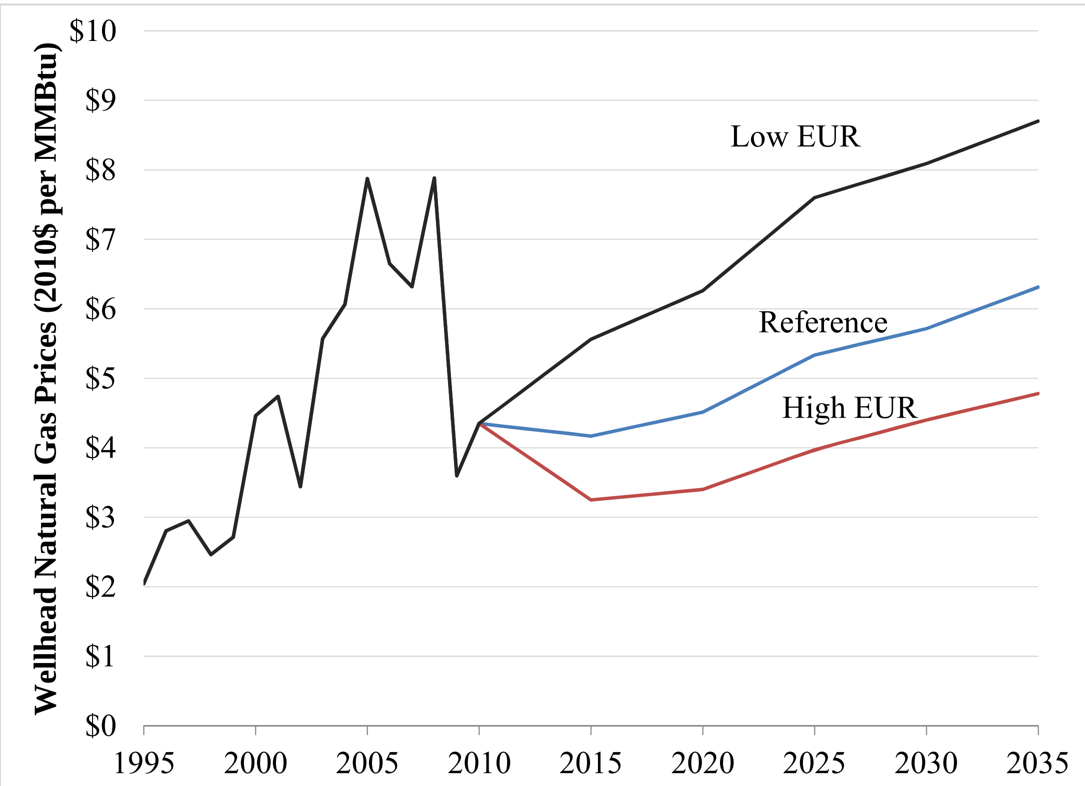
[17] NERA also ran 3 cases in which the LNG export capacity was assumed to be unlimited.

B. Natural Gas Market Impacts

1. Price, Production, and Demand

The wellhead natural gas price increases steadily in all three of the baseline cases (REF, High EUR and Low EUR). Under the REF case the wellhead price increases from $4.40/MMBtu in 2010 to $6.30/MMBtu while under the High EUR and the Low EUR cases the price increases to about $4.80/MMBtu (a 10% increase from the 2010 price) and $8.70/MMBtu (a 100% increase from 2010), respectively. Comparing the projected natural gas price under the three baseline cases with historical natural gas prices, we see that the prices exceed recent historical highs only under the Low EUR case beyond 2030 (see Figure 27). The natural gas price path and its response in the scenarios with LNG exports will depend on the availability and accessibility of natural gas resources. Additionally, the price changes will be influenced by the expansion rate of LNG exports. The lower level of supply under the Low EUR case results in a higher projected natural gas price while the High EUR case, with abundant shale gas, results in a lower projected natural gas price path.

Figure 27: Historical and Projected Wellhead Natural Gas Price Paths



Source: Energy Information Agency (EIA)

The extent of the natural gas price response to an expansion of LNG exports depends upon the supply and demand conditions and the corresponding baseline price. For a given baseline, the higher the level of LNG exports the greater the change in natural gas price. Similarly, the natural gas price rises much faster under a scenario that has a quicker rate of expansion of LNG exports.

From Figure 28 we can see that under the Low/Rapid expansion scenario, USREF_SD_LR, the price rises by 7.7% in 2015 while under the Low/Slow expansion scenario, USREF_SD_LS, the price rises by only 2.4% in 2015. The demand for LNG exports in the Low/Rapid scenario (1.1 Tcf) is much greater than in the Low/Slow scenarios (0.37 Tcf); hence, the pressure on the natural gas price in the Low/Rapid scenario is higher. However, post-2015 LNG export volumes are the same in both scenarios, thus leading to the same level of increase in the wellhead price. The wellhead price rises 14% by 2020 relative to the baseline and then tapers off to a 6.4% increase by 2035 under both scenarios.

For the same Reference case baseline, Bau_Ref, the wellhead natural gas price varies by export level scenarios. The NERA High/Rapid export scenario (USREF_SD_HR) leads to the largest price increases of about 20% in 2020 ($0.90/Mcf) and 14% in 2035 ($0.90/Mcf) relative to the Reference baseline. The increase in the wellhead price is the smallest for the NERA low export scenarios (USREF_D_LS, USREF_D_LR and USREF_D_LSS). The Low/Slowest export scenario, USREF_D_LSS, has a 2015 increase of about 1% ($0.05/Mcf) and a 2035 price increase of about 4% ($0.25/Mcf).

The price increase for the High EUR scenarios is similar to the increases in the EIA Study since the export volumes are the same.[18] The largest increase in price takes place under the High/Rapid scenario in 2020 (32% relative to the High EUR baseline). However, as quickly as the price rises in 2020 it only increases by 21% in 2025 and 13% in 2025 relative to the High EUR baseline.[19] To put the percentage change in context, Figure 29 shows the level value changes relative to the corresponding baseline. Given the lower baseline price under the High EUR case, the absolute increase in the natural gas prices is smaller under the High EUR scenarios than the Reference case scenarios. The price increase under the Low EUR scenario with the slowest export volume is only a 6% increase in price relative to the baseline, or about $0.40/Mcf.

A higher natural gas price in the scenarios has three primary impacts on the overall economy. First, it tends to increase the cost of producing goods and services that are dependent on natural gas, which leads to decreasing economic output. Second, the higher price of natural gas leads to an increase in export revenues, which improves the balance of payment position. Third, it provides wealth transfer in the form of take-or-pay tolling charges that support the income of the consumers. The overall macroeconomic impacts depend on the magnitudes of these three effects as discussed in the next section.

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[18] See Appendix D for comparison of natural gas prices.

[19] Since the results are shown for three baselines with three different prices, comparing percentage changes across these baseline cases can be misleading since they do not correspond to the same level value changes. In general, when comparing scenarios between Reference and High EUR cases, the level change would be smaller under the High EUR case for the same percentage increase in price.

Figure 28: Wellhead Natural Gas Price and Percentage Change for NERA Core Scenarios

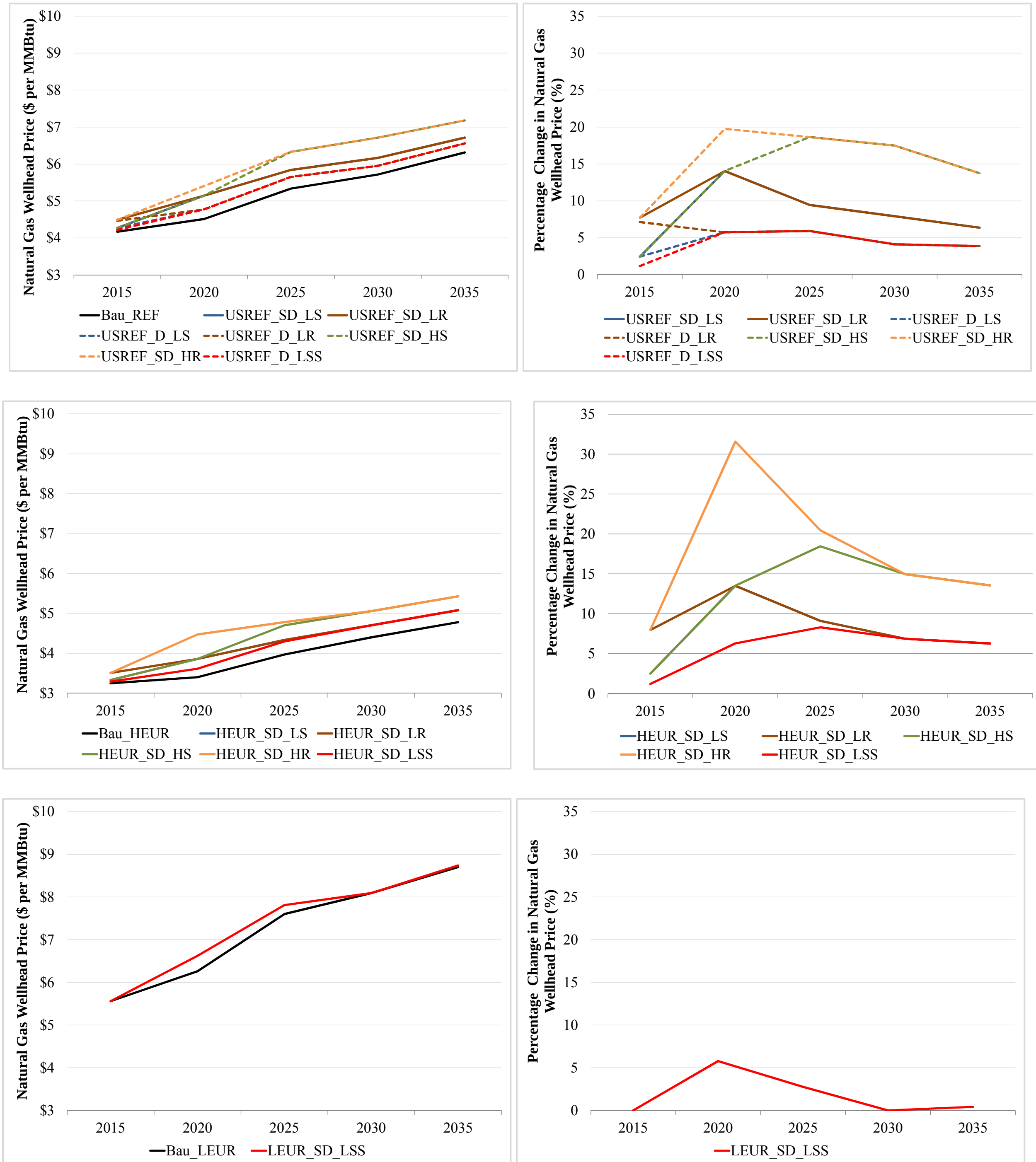


Figure 29: Change in Natural Gas Price Relative to the Corresponding Baseline of Zero LNG Exports (2010$/Mcf)

	2015	2020	2025	2030	2035
USREF_SD_LR	$0.33	$0.65	$0.52	$0.47	$0.41
USREF_SD_LS	$0.10	$0.65	$0.52	$0.47	$0.41
USREF_SD_HR	$0.33	$0.92	$1.02	$1.03	$0.89
USREF_SD_HS	$0.10	$0.65	$1.02	$1.03	$0.89
USREF_D_LR	$0.31	$0.27	$0.33	$0.24	$0.25
USREF_D_LS	$0.10	$0.27	$0.33	$0.24	$0.25
USREF_D_LSS	$0.05	$0.27	$0.33	$0.24	$0.25
HEUR_SD_HR	$0.27	$1.11	$0.84	$0.68	$0.67
HEUR_SD_HS	$0.08	$0.47	$0.75	$0.68	$0.67
HEUR_SD_LR	$0.27	$0.47	$0.37	$0.31	$0.31
HEUR_SD_LS	$0.08	$0.47	$0.37	$0.31	$0.31
HEUR_SD_LSS	$0.04	$0.22	$0.34	$0.31	$0.31
LEUR_SD_LSS	$0.00	$0.37	$0.22	$0.00	$0.04

Natural gas production increases under all three baseline cases to partially support the rise in export volumes in all of the scenarios. In the Reference case, the high scenarios (USREF_SD_HS and USREF_SD_HR) have production steadily increasing by about 10% in 2035 with production in the High/Slow scenario rising at a slower pace than in the High/Rapid scenario. In the low scenarios (USREF_SD_LS and USREF_SD_LR) and the slowest scenario (USREF_D_LSS), the production increases by about 5% and 3% in 2035, respectively (see the first two panels in Figure 30). The rise in production under the High EUR case scenarios is smaller than the corresponding Reference case scenarios.

The response in natural gas production depends upon the nature of the supply curve. Production is much more constrained in the short run as a result of drilling needs and other limitations. In the long run, gas producers are able to overcome these constraints. Hence there is more production response in the long run than in the short run.[20] Figure 30 shows that in 2015 the increase in production accounts for about 30% to 40% of the export volume, while in 2035 due to gas producers overcoming production constraints, the share of the increase in production in export volumes increases to about 60%.

[20] In the short run, the natural gas supply curve is much more inelastic than in the long run.

Figure 30: Natural Gas Production and Percentage Change for NERA Core Scenarios

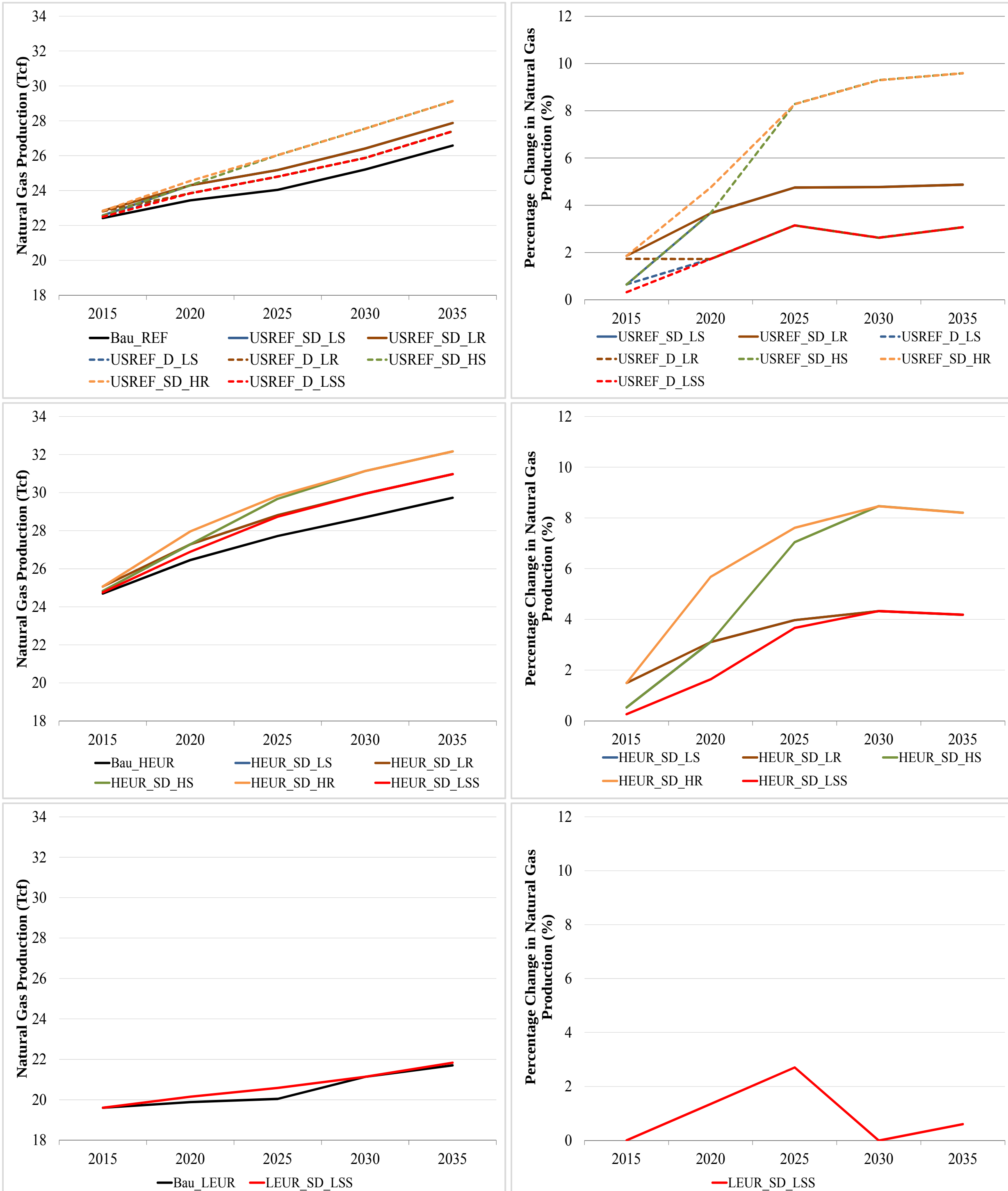


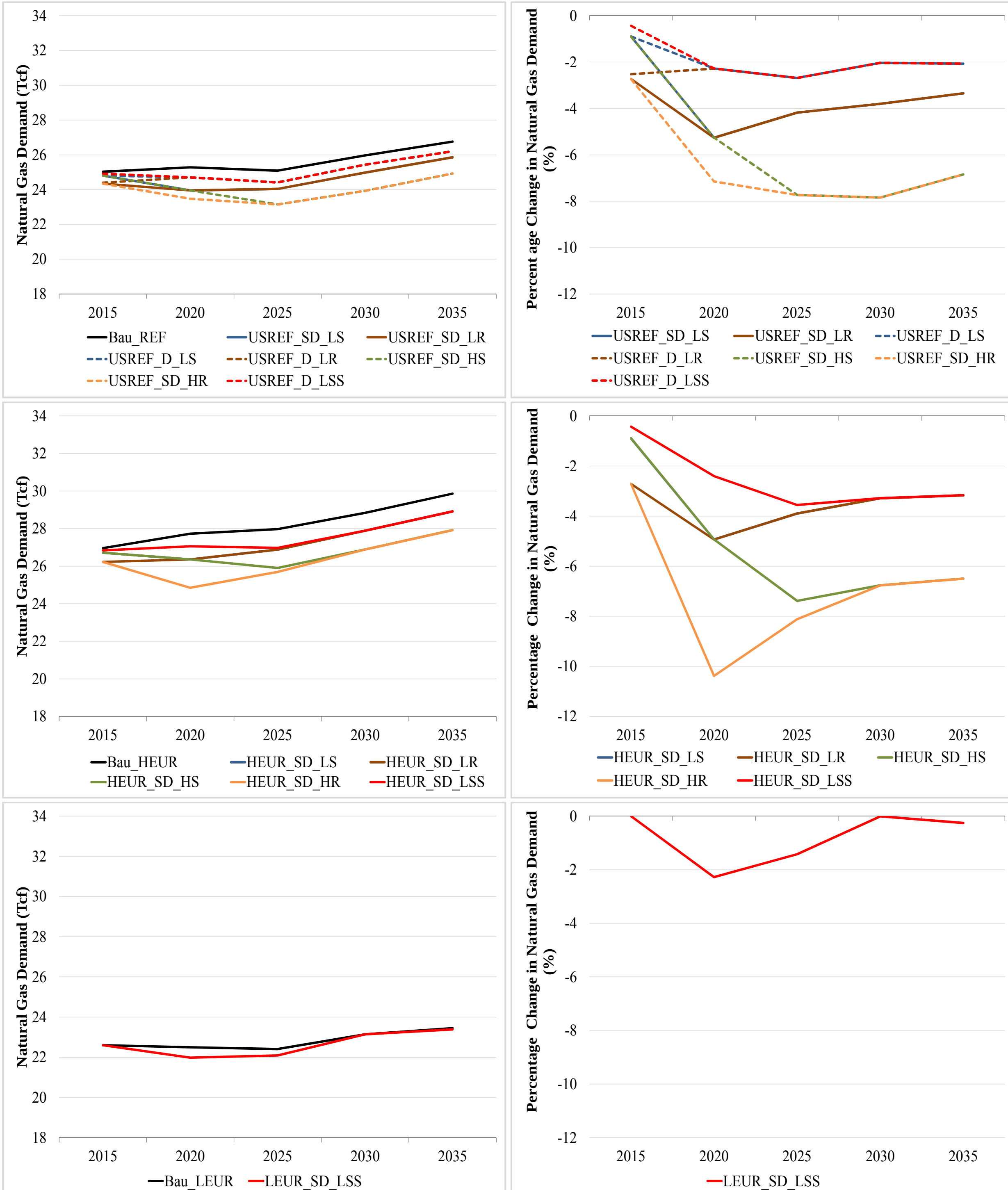
Figure 31: Change in Natural Gas Production Relative to the Corresponding Baseline (Tcf)

Scenario	Increase in Production (Tcf)					Ratio of Increase in Production to Export Volumes				
	2015	2020	2025	2030	2035	2015	2020	2025	2030	2035
USREF_SD_LR	0.42	0.86	1.14	1.20	1.29	38%	39%	52%	55%	59%
USREF_SD_LS	0.15	0.86	1.14	1.20	1.29	39%	39%	52%	55%	59%
USREF_SD_HR	0.42	1.11	1.99	2.34	2.55	38%	38%	51%	53%	58%
USREF_SD_HS	0.14	0.86	1.99	2.34	2.55	39%	39%	51%	54%	58%
USREF_D_LR	0.39	0.40	0.76	0.66	0.82	35%	41%	53%	56%	60%
USREF_D_LS	0.15	0.40	0.76	0.66	0.82	39%	41%	53%	56%	37%
USREF_D_LSS	0.07	0.40	0.76	0.66	0.82	40%	41%	53%	56%	60%
HEUR_SD_HR	0.37	1.50	2.11	2.43	2.44	34%	34%	48%	55%	56%
HEUR_SD_HS	0.13	0.82	1.95	2.43	2.44	35%	38%	49%	55%	56%
HEUR_SD_LR	0.37	0.82	1.10	1.24	1.24	34%	37%	50%	57%	57%
HEUR_SD_LS	0.13	0.82	1.10	1.24	1.24	35%	38%	50%	57%	57%
HEUR_SD_LSS	0.06	0.43	1.02	1.24	1.24	35%	39%	51%	57%	57%
LEUR_SD_LSS	0.00	0.27	0.54	0.00	0.13	0%	34%	63%	0%	69%

The increase in natural gas price has three main impacts on the production of goods and services that primarily depend upon natural gas as a fuel. First, the production processes would switch to fuels that are relatively cheaper. Second, the increase in fuel costs would result in a reduction in overall output. Lastly, the price increase would induce new technology that could more efficiently use natural gas. All of these impacts would reduce the demand for natural gas. The extent of this demand response depends on the ease of substituting away from natural gas in the production of goods and services. Pipeline imports into the U.S. are assumed to remain unchanged between scenarios within a given baseline case. Pipeline imports for the Reference, High EUR, and Low EUR cases are calibrated to the EIA's AEO 2011 projections. Figure 32 shows the natural gas demand changes for all cases and scenarios. The largest drop in natural gas demand occurs in 2020 when the natural gas price increases the most.

In the Reference and High EUR cases, the high scenarios are projected to have the largest demand response because overall prices are the highest. The largest drop in natural gas demand in 2020 for the Reference, High EUR, and Low EUR is about 8%, 10%, and 2%, respectively. In the long run (2035), natural gas demand drops by about 5% for the Reference and the High EUR cases while there is no response in demand under the Low EUR case. In general, the largest drop in natural gas demand corresponds to the year and scenario in which the price increase is the largest. For the High/Rapid scenario under the High EUR case, the largest drop occurs in 2020. Given that the implied price elasticity of demand is similar across all cases, the long-run demand impacts across cases tend to converge for the corresponding scenarios. Figure 32 shows the demand for all scenarios.

Figure 32: Natural Gas Demand and Percent Change for NERA Core Scenarios



C. Macroeconomic Impacts

1. Welfare

Expansion of natural gas exports changes the price of goods and services purchased by U.S. consumers. In addition, it also alters the income level of the consumers through increased wealth transfers in the form of tolling charges on LNG exports. These economic effects change the well-being of consumers as measured by equivalent variation in income. The equivalent variation measures the monetary impact that is equivalent to the change in consumers' utility from the price changes and provides an accurate measure of the impacts of a policy on consumers.[21]

We report the change in welfare relative to the baseline in Figure 33 for all the scenarios. A positive change in welfare means that the policy improves welfare from the perspective of the consumer. All export scenarios are welfare-improving for U.S. consumers. The welfare improvement is the largest under the high export scenarios even though the price impacts are also the largest. Under these export scenarios, the U.S. consumers[22] receive additional income from two sources. First, the LNG exports provide additional export revenues, and second, consumers who are owners of the liquefaction plants, receive take-or-pay tolling charges for the amount of LNG exports. These additional sources of income for U.S. consumers outweigh the loss associated with higher energy prices. Consequently, consumers, in aggregate, are better off as a result of opening up LNG exports.

Comparing welfare results across the scenarios, the change in welfare of the low export volume scenarios for the High EUR case is about half that of the corresponding scenarios for the Reference case (see Figure 33). The welfare impacts under the Reference case scenarios are higher than for corresponding High EUR case scenarios. Under the High EUR case, the wellhead price is much lower than the Reference case and therefore results in lower welfare impacts. Similarly in both the Reference and High EUR cases, the high export volume scenarios have much larger welfare impacts than the lower export volume scenarios. Again, the amount of wealth transfer under high export volume scenarios drives the higher welfare impacts. In fact, the U.S. consumers are better off in all of the export volume scenarios that were analyzed.

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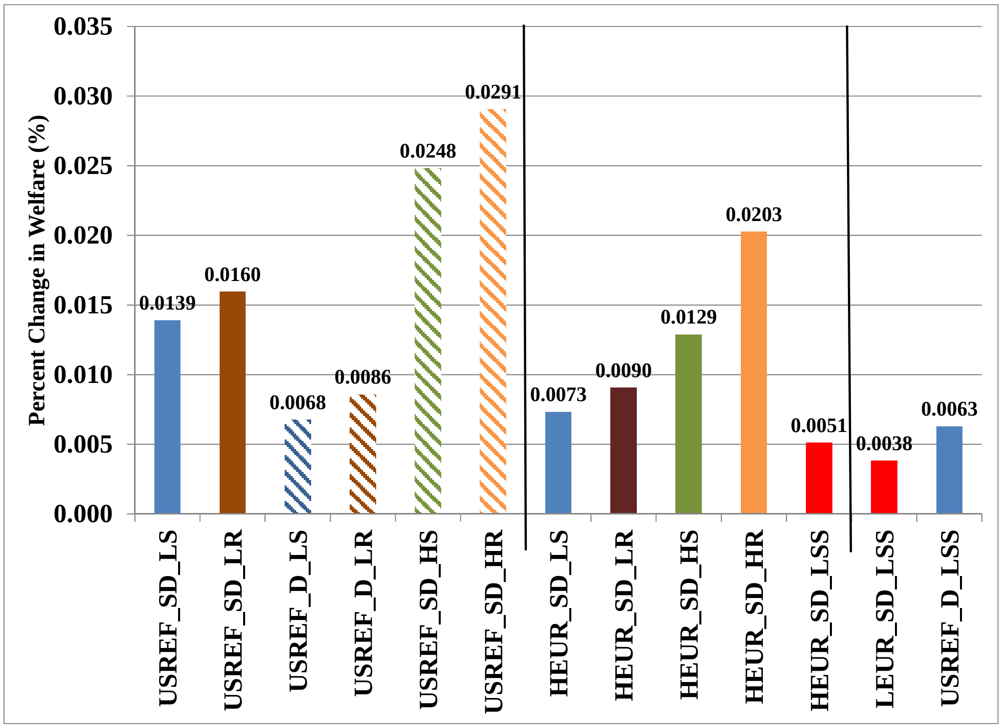
[21] *Intermediate Microeconomics: A Modern Approach*, Hal Varian, 7th Edition (December 2005), W.W. Norton & Company, pp. 255-256. "Another way to measure the impact of a price change in monetary terms is to ask how much money would have to be taken away from the consumer *before* the price change to leave him as well off as he would be *after* the price change. This is called the **equivalent variation** in income since it is the income change that is equivalent to the price change in terms of the change in utility." (emphasis in original).

[22] Consumers own all production processes and industries by virtue of owning stock in them.

Figure 33: Percentage Change in Welfare for NERA Core Scenarios[23]



2. GDP

GDP is another economic metric that is often used to evaluate the effectiveness of a policy by measuring the level of total economic activity in the economy. In the short run, the GDP impacts are positive as the economy benefits from investment in the liquefaction process, export revenues, resource income, and additional wealth transfer in the form of tolling charges. In the long run, GDP impacts are smaller but remain positive because of higher resource income.

A higher natural gas price does lead to higher energy costs and impacts industries that use natural gas extensively. However, the effects of higher price do not offset the positive impacts from wealth transfers and result in higher GDP over the model horizon in all scenarios. In the high scenarios and especially in periods with high natural gas prices, the export revenue stream increases while increasing the natural gas resource income as well. These effects combined with wealth transfer lead to the largest positive impacts on the GDP. In all scenarios, the impact on GDP is the largest in 2020 then drops as the export volumes stabilize. In a subsequent section, we discuss changes in different sources of household income.

Under the Reference case, the change in GDP in 2015 is between 0.01% for the Low/Slowest scenario to 0.05% in the High/Rapid scenario. The increase in GDP in the High EUR case is as large as 0.26% because resource income and LNG exports are the greatest. Overall, GDP

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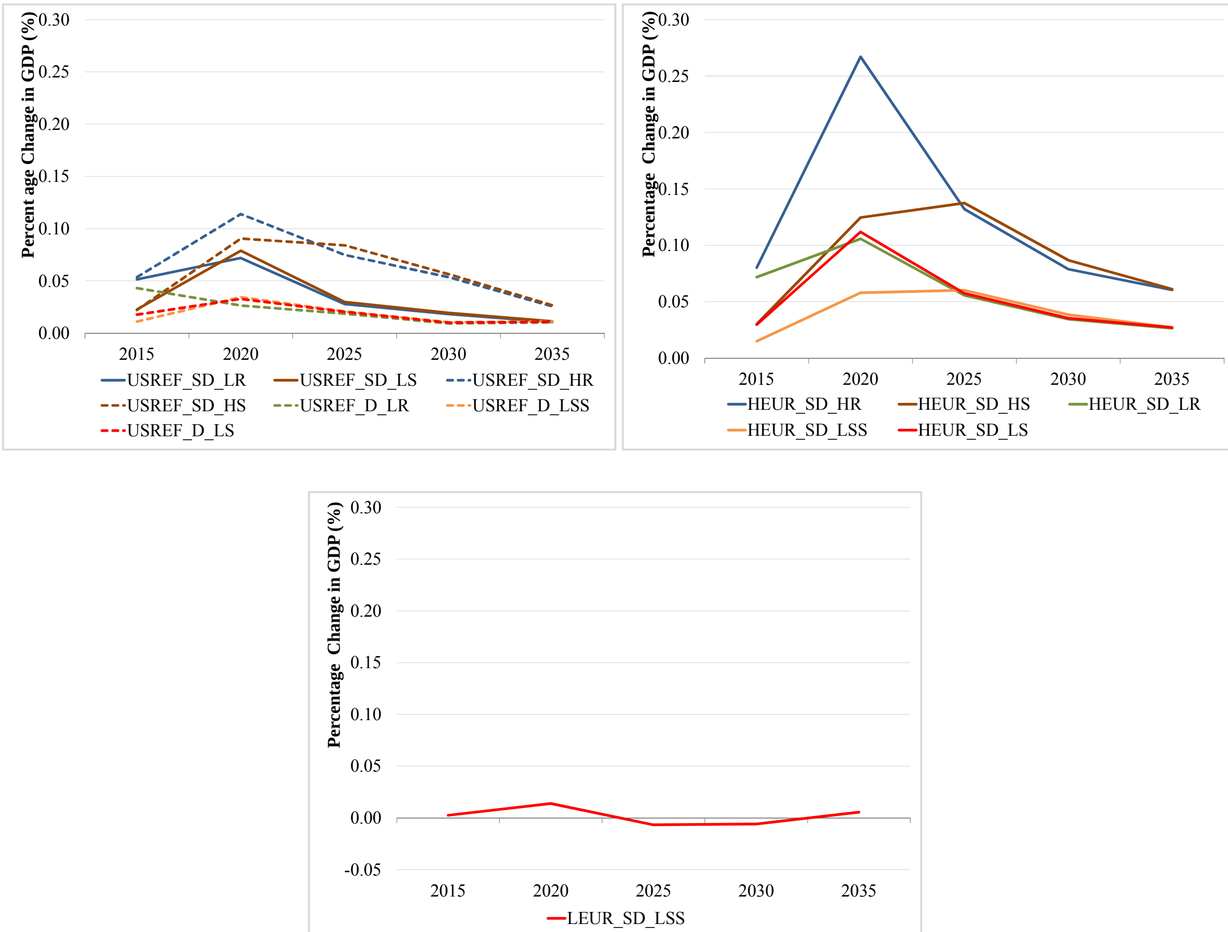
23 Welfare is calculated as a single number that represents in present value terms the amount that households are made better (worse) off over the entire time horizon from 2015 to 2035.

impacts are positive for all scenarios with higher impact in the short run and minimum impact in the long run.

Figure 34: Percentage Change in GDP for NERA Core Scenarios

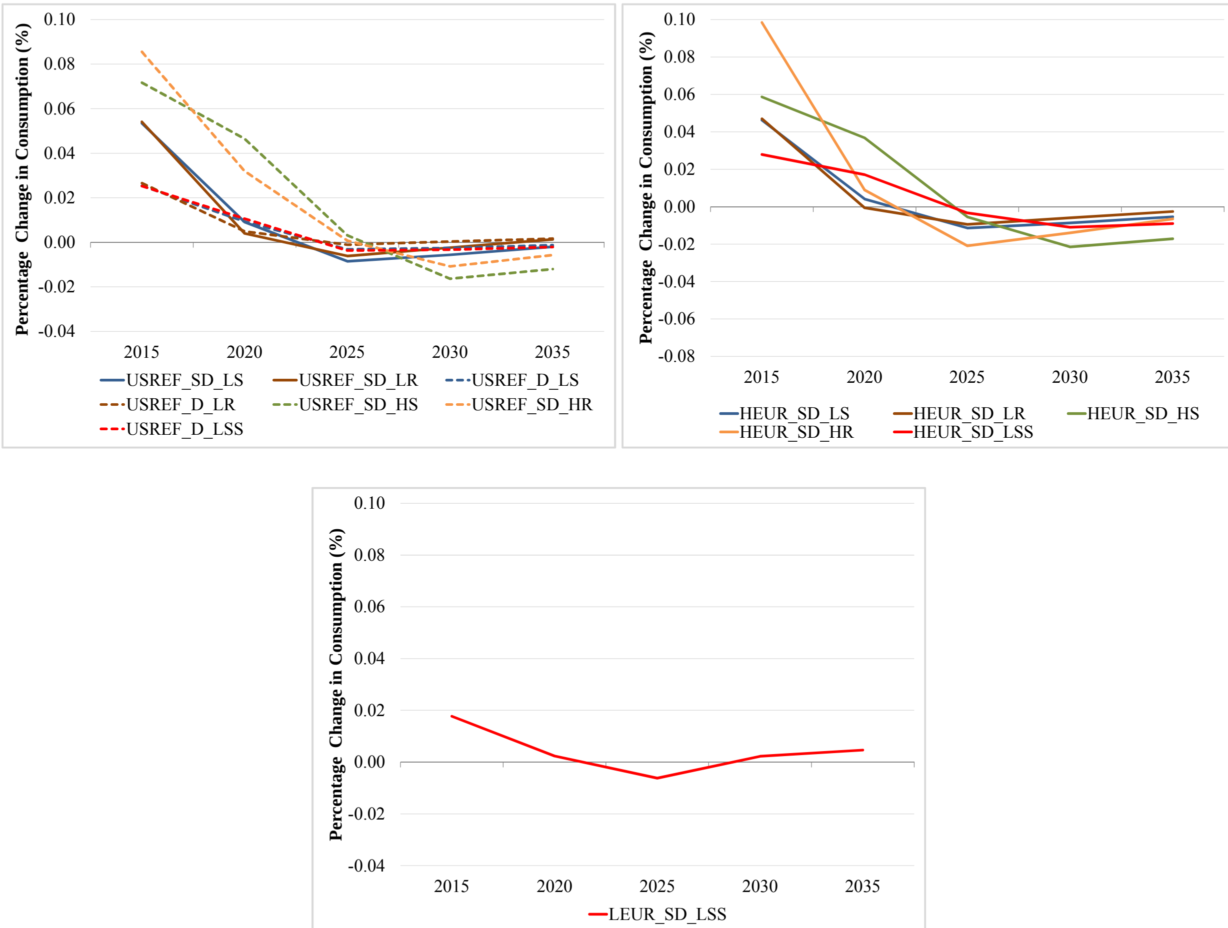


3. Aggregate Consumption

Aggregate consumption measures the total spending on goods and services in the economy. In 2015, consumption increases from the No-Export case between 0.02% for the low scenarios to 0.8% for the high scenarios. Consumption impacts for the High EUR scenarios also show similar impacts (Figure 35). Under the High/Rapid scenarios, the increase in consumption in 2015 is much greater (0.10%) because higher export volumes result in leading to much larger export revenue impacts. By 2035, consumption decreases by less than 0.02%.

Higher aggregate spending or consumption resulting from a policy suggests higher economic activity and more purchasing power for the consumers. The scenario results of the Reference case, seen in Figure 35, show that the consumption increases or remains unchanged until 2025 for almost all of the scenarios. These results suggest that the wealth transfer from exports of LNG provides net positive income for the consumers to spend after taking into account potential decreases in capital and wage income from reduced output.

Figure 35: Percentage Change in Consumption for NERA Core Scenarios



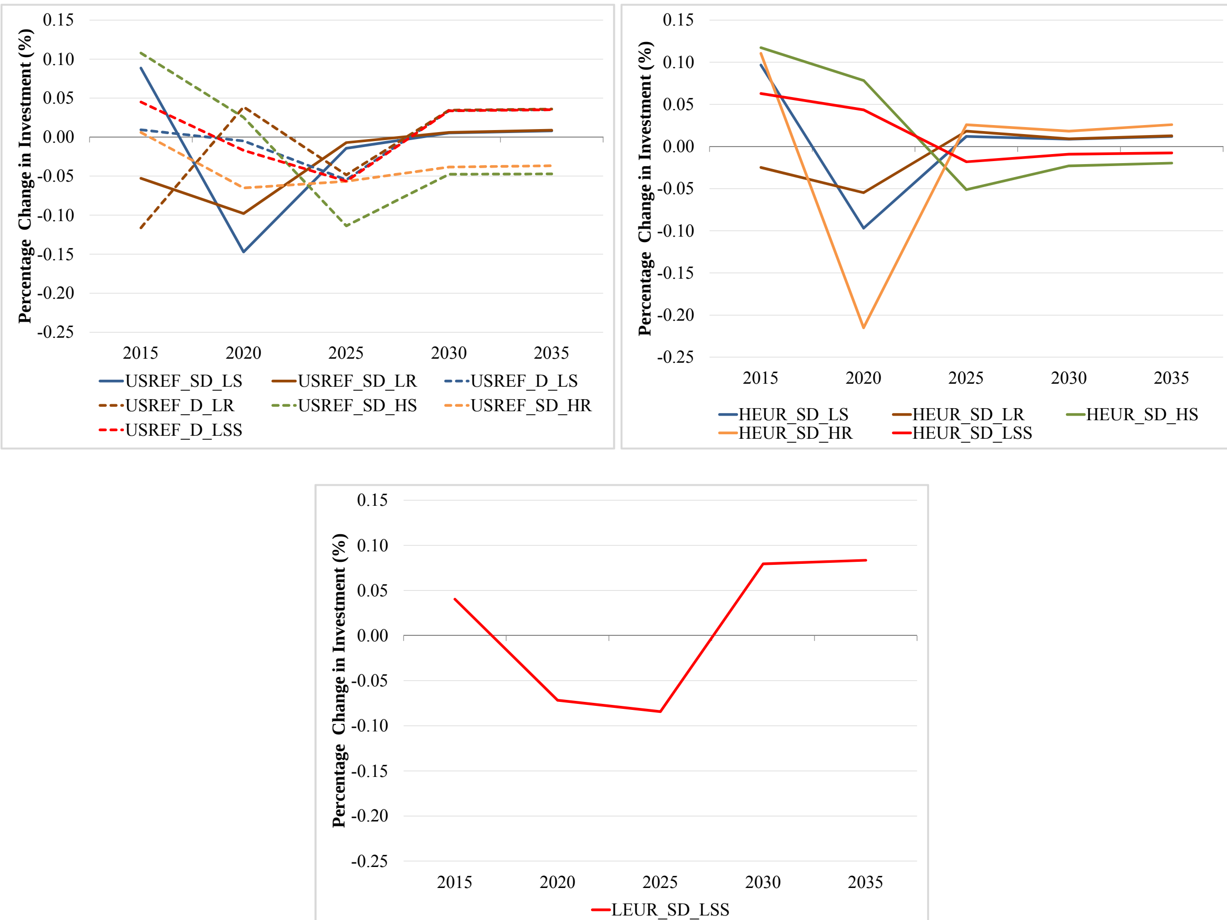
4. Aggregate Investment

Investment in the economy occurs to replace old capital and augment new capital formation. In this study, additional investment also takes place to convert current regasification plants to liquefaction plants and/or build new green-field liquefaction plants. The investment that is necessary to support the expansion of LNG exports is largest in 2015.[24] The investment outlay under each of the LNG export expansion scenarios is discussed in Appendix C. In 2015 and 2020, investment increases to support higher consumption (and production) of goods and services and investment in the liquefaction plants. As seen in Figure 36, investment increases for all scenarios, except for the Low/Rapid scenarios. Investment in 2015 could increase by as much as 0.10%. As the price of natural gas increases, the economy demands or produces fewer goods and services. This results in lower wages and capital income for consumers. Hence, under such economic conditions, consumers save less of their income for investment. The investment drop is the largest under the High EUR case for the High/Rapid scenario (-0.2%) where industrial

24 Each model year represents a span of five years, thus the investment in 2015 represents an average annual investment between 2015 and 2019.

decline is the largest because of the increases in energy prices in general and the natural gas price in particular. As with consumption, the results for the low scenarios under the Reference and High EUR cases (with the same level of LNG exports) show similar investment changes. The range of change in investment over the long run (2030 through 2035) for all scenarios is between -0.05% and 0.08%.

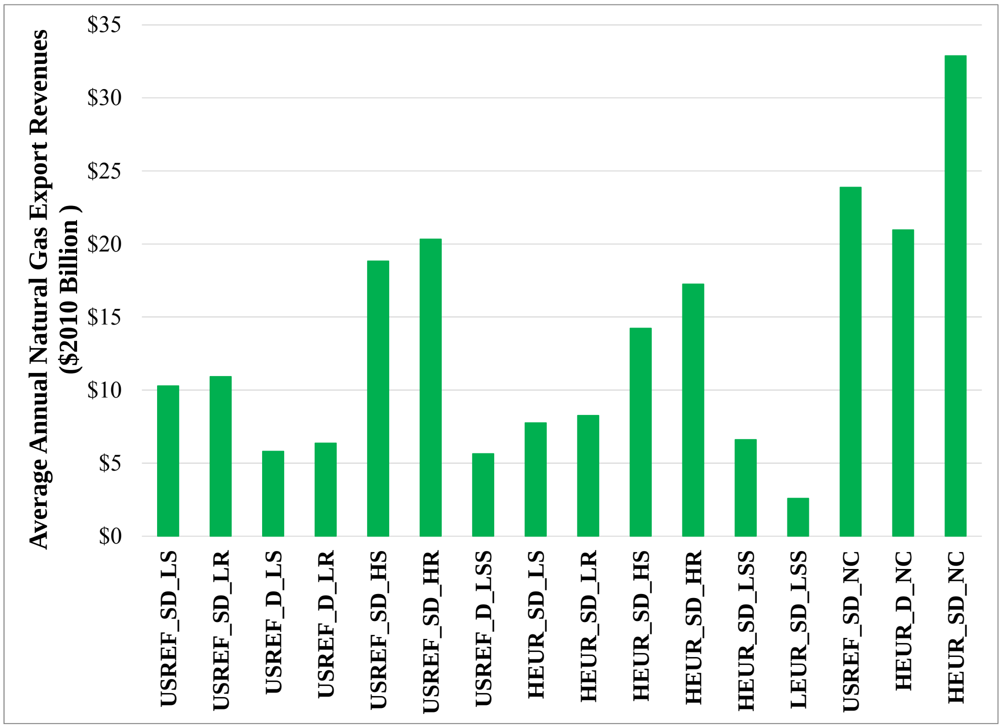
Figure 36: Percentage Change in Investment for NERA Core Scenarios



5. Natural Gas Export Revenues

As a result of higher levels of natural gas exports and increased natural gas prices, LNG export revenues offer an additional source of income. Depending on the baseline case and scenario used, the average annual increase in revenues from LNG exports ranges from about $2.6 billion (2010$) to almost $32.9 billion (2010$) as seen in Figure 37. Unsurprisingly, the high end of this range is from the unconstrained scenario, while the low end is the Low/Slowest scenario. The average revenue increase in all of the high scenarios for each baseline is roughly double the increase in the low scenarios. The difference in revenue increases between comparable rapid and slow scenarios is about 6% to 20%, with the low scenarios showing a smaller difference between their rapid and slow counterparts than the high scenarios.

Figure 37: Average Annual Increase in Natural Gas Export Revenues

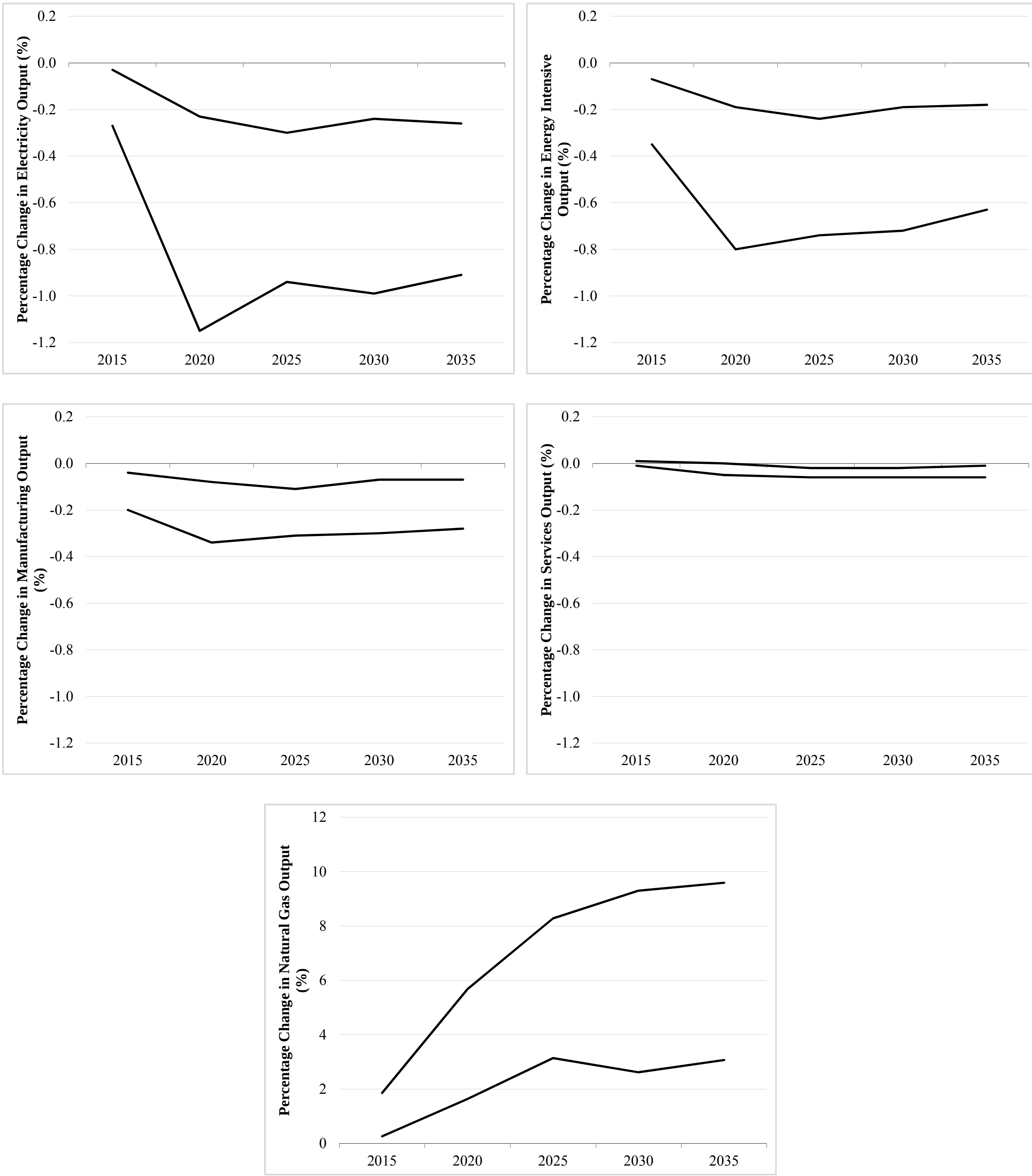


6. Range of Sectoral Output Changes for Some Key Economic Sectors

Changes in natural gas prices have real effects throughout the economy. Economic sectors such as the electricity sector, energy-intensive sectors ("EIS"), the manufacturing sector, and the services sector are dependent on natural gas as a fuel and are therefore vulnerable to natural gas price increases. These particular sectors will be disproportionately impacted leading to lower output. In contrast, natural gas producers and sellers will benefit from higher natural gas prices and output. These varying impacts will shift income patterns between economic sectors. The overall effect on the economy depends on the degree to which the economy adjusts by fuel switching, introducing new technologies, or mitigating costs by compensating parties that are disproportionately impacted.

Figure 38 illustrates the minimum and maximum range of changes in some economic sectors. The range of impacts on sectoral output varies considerably by sector. The electricity and EIS sectoral output changes are the largest across all scenarios. Maximum losses in electricity sector output could be between 0.2% and 1%, when compared across all scenarios while the decline in output of EIS could be between 0.2% and 0.8%. The manufacturing sector, being a modest consumer of natural gas, sees a fairly narrow range of plus or minus 0.5% loss in output around 0.2%. Since the services sector is not natural gas intensive (one-third of the natural gas is consumed by the commercial sector), the impact this sector's output is minimal.

Figure 38: Minimum and Maximum Output Changes for Some Key Economic Sectors

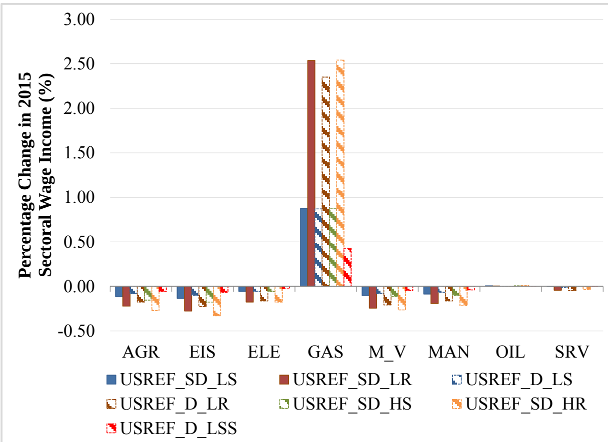


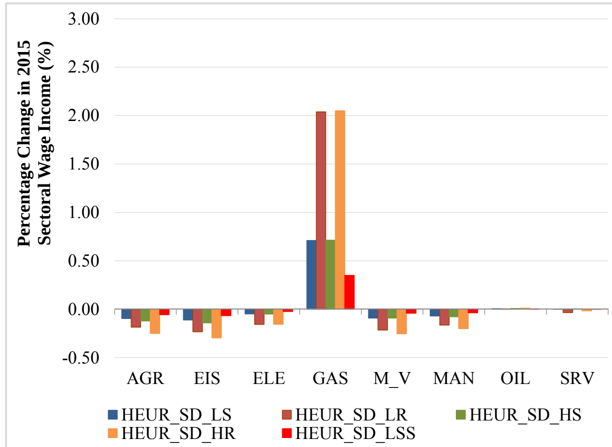
7. Wage Income and Other Components of Household Income

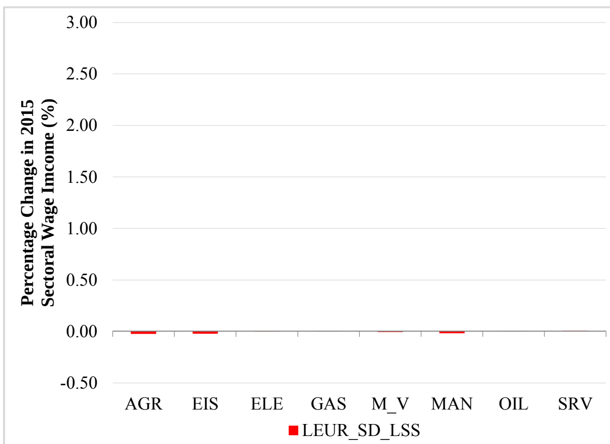
Sectoral output, discussed in the previous section, translates directly into changes in input levels for a given sector. In general, if the output of a sector increases so do the inputs associated with the production of this sector's goods and services. An increase in natural gas output leads to more wage income in the natural gas sector as domestic production increases. In the short run, industries are able to adjust to changes in demand for output by increasing employment if the sector expands or by reducing employment if the sector contracts.

Figure 39 shows the change in total wage income in 2015 for all scenarios. Wage income decreases in all industrial sectors except for the natural gas sector. Services and manufacturing sectors see the largest change in wage income in 2015 as these are sectors that are highly labor intensive.

Figure 39: Percentage Change in 2015 Sectoral Wage Income







As seen from the discussion above, the overall macroeconomic impacts are driven by the changes in the sources of household income. Households derive income from capital, labor, and resources. These value-added incomes also form a large share of GDP and aggregate consumption. Hence, to tie all the above impacts together, we illustrate the magnitude of each of the income subcomponents and how they relate to the overall macroeconomic impacts in Figure 40.

Figure 40: Changes in Subcomponents of GDP in 2020 and 2035

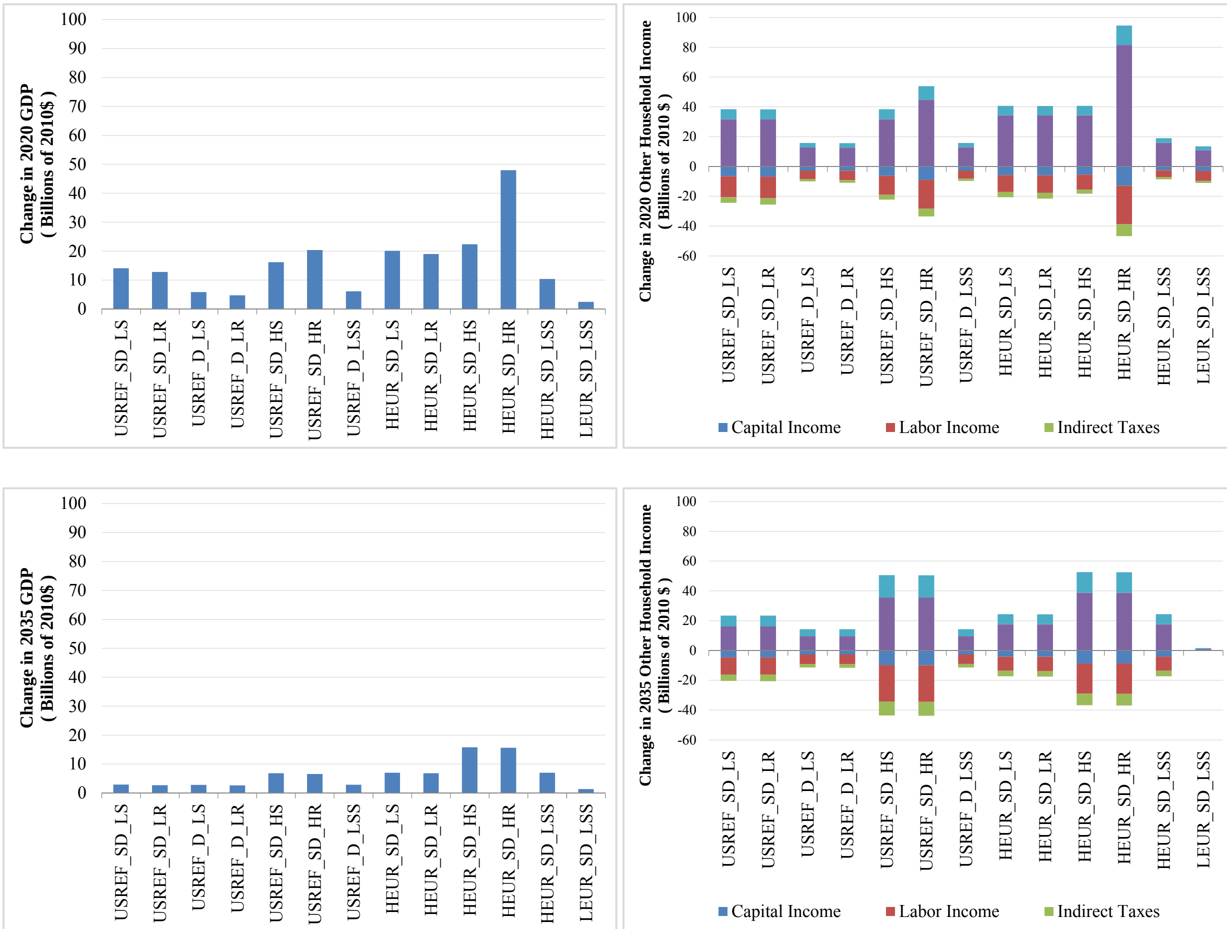


Figure 40 shows a snapshot of changes in GDP and household income components in 2020 and 2035. GDP impacts in 2020 provide the largest increase, while 2035 impacts provide a picture of the long run changes. Capital income, wage income, and indirect tax revenues drop in all scenarios, while resource income and net transfers associated with LNG export revenues increase in all scenarios. As previously discussed, capital and wage income declines are caused by high fuel prices leading to reductions in output and hence lower demand for input factors of production. However, there is positive income from higher resource value and net wealth transfer. This additional source of income is unique to the export expansion policy. This leads to the total increase in household income exceeding the total decrease. The net positive effect in real income translates into higher GDP and consumption.[25]

[25] The net transfer income increases even more in the case where the U.S. captures quota rents leading to a net benefit to the U.S. economy.

D. Impacts on Energy-Intensive Sectors

1. Output and Wage Income

The EIS sector includes the following 5 energy using subsectors identified in the IMPLAN[26] database:

1) Paper and pulp manufacturing (NAICS 322);

2) Chemical manufacturing (NAICS 326);

3) Glass manufacturing (NAICS 3272);

4) Cement manufacturing (NAICS 3273); and

5) Primary metal manufacturing (NAICS 331) that includes iron, steel and aluminum.[27]

As the name of this sector indicates, these industries are very energy intensive and are dependent on natural gas as a key input.[28]

The model results for EIS industrial output are shown in Figure 41 for all scenarios. Because of the heavy reliance on natural gas as input, the impact on the sector is driven by natural gas prices. Under the Reference case for the high scenarios, output declines by about 0.7% while under the High EUR case output declines by about 0.8% in 2020 and then settles at around 0.6%. The reduction in EIS output for the low scenarios is less than 0.4%. Under the Low EUR case and Low/Slowest export volume scenario EIS, output changes minimally. Overall, EIS reduction is less that 1.0%.

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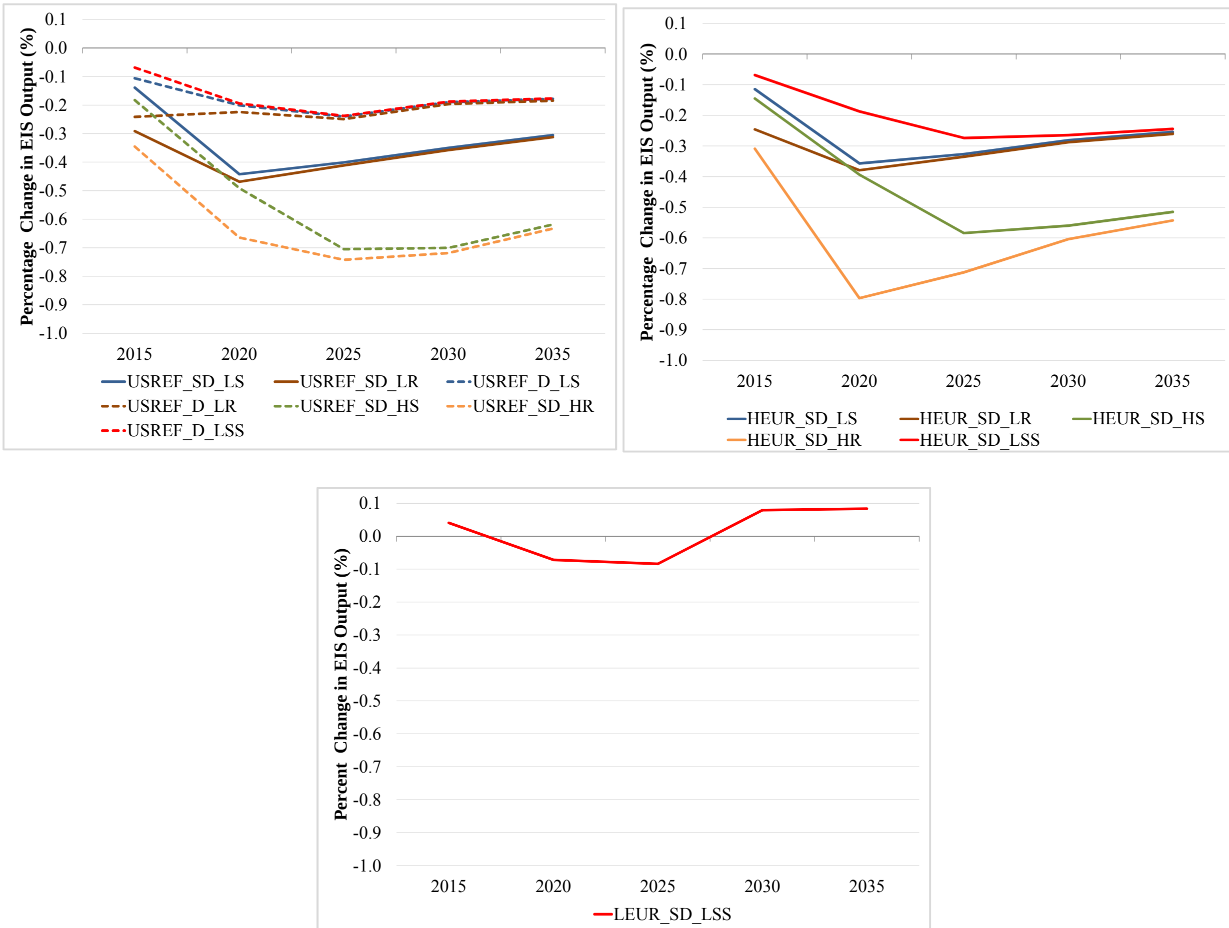
[26] IMPLAN dataset provides inter-industry production and financial transactions for all states of the U.S. (www.implan.com).

[27] The North American Industry Classification System ("NAICS") is the standard used to classify business establishments.

[28] For this study, we have represented the EIS sector based on a 3-digit classification that aggregates upstream and downstream industries within each class. Thus, in aggregating at this level the final energy intensity would be less than one would expect if only we were to aggregate only the downstream industries or at higher NAICS-digit levels.

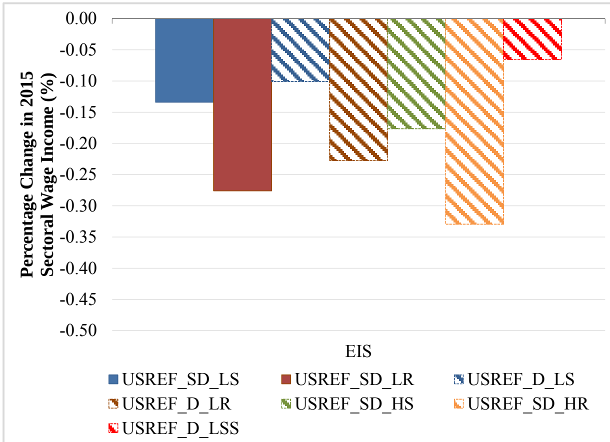
Figure 41: Percentage Change in EIS Output for NERA Core Scenarios

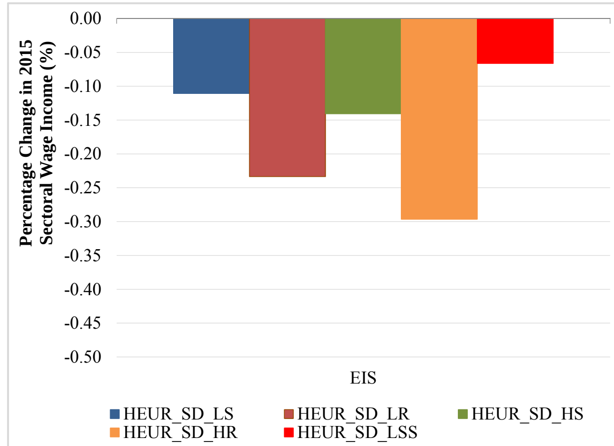


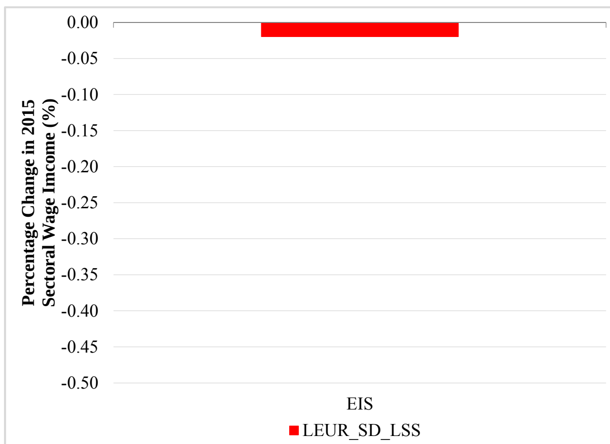
As mentioned in the previous sections, a reduction in sectoral output means intermediate input demand also is reduced. The EIS sector declines result in lower demand for labor, capital, energy, and other intermediate goods and services.

Figure 42 shows the changes in wage income in 2015. Under the Reference outlook, wage income would be about 0.10% to about 0.40% below baseline levels, which still represents real wage growth over time. The largest slowdown in the growth of wage income occurs in periods where reductions in EIS industrial output relative to baseline are the largest. Since the increase in natural gas prices is highest under the high/Rapid scenarios with the HEUR Shale gas outlook, the largest total labor compensation decrease in EIS occurs in that scenario, a decrease of about 0.70% in 2020 relative to baseline. Wage income never falls short of baseline levels by more than 1% in any year or any industry in any scenario.

Figure 42: Percentage Change in 2015 Energy Intensive Sector Wage Income for NERA Core Scenarios







2. Rate of Change

Even if this entire change in wage income in EIA represented a shift of jobs out of the sector, the change in EIS employment would be relatively small compared to normal turnover in the industries concerned and, under normal economic conditions, would not necessarily result in any change in aggregate employment other than a temporary increase in the number of workers between jobs. This can be seen by comparing the average annual change in employment to annual turnover rates by industry. The annual Job Openings and Labor Turnover (JOLTS) survey done by the Bureau of Labor Statistics[29] shows that the lowest annual quits rate observed, representing voluntary termination of employment in the worst year of the recession, was 6.9% for durable goods manufacturing. The largest change in wage income in the peak year of a scenario, with the largest increases in natural gas prices, is a reduction of about 5% in a 5-year period, or less than 1% per year. This is less than 15% of the normal turnover rate in that industry.

[29] "Job Openings and Labor Turnover," Bureau of Labor Statistics, January 2012, Table 16.

3. Harm is Likely to be Confined to Very Narrow Segments of Industry

To identify where higher natural gas prices might cause severe impacts such as plant closings (due to an inability to compete with overseas suppliers not experiencing similar natural gas price increases), it is necessary to look at much smaller slices of U.S. manufacturing. Fortunately, this was done in a study by an Interagency Task Force in 2007 that analyzed the impacts of proposed climate legislation, the Waxman-Markey bill (H.R.2454), on energy-intensive, trade-exposed industries ("EITE") using data from the 2007 Economic Census.[30] The cap-and-trade program in the Waxman-Markey bill would have caused increases in energy costs and impacts on EITE even broader than would the allowing of LNG exports because the Waxman-Markey bill applied to all fuels and increased the costs of fuels used for about 70% of electricity generation. Thus, the Task Force's data and conclusions are directly relevant.

The Interagency Report defined an industry's energy intensity as "its energy expenditures as a share of the value of its domestic production."[31] The measure of energy intensity used in the Interagency Report included all sources of energy, including electricity, coal, fuel oil, and natural gas. Thus, natural gas intensity will be even less than energy intensity.

The Interagency Report further defined an energy-intensive, trade-exposed industry (those that were "presumptively eligible" for emission allowance allocations under the Waxman-Markey bill) as ones where the industry's "energy intensity or its greenhouse gas intensity is at least 5 percent, and its trade intensity is at least 15 percent."[32]

The Interagency Report found:

> *According to the preliminary assessment of the nearly 500 six-digit manufacturing industries, 44 would be deemed "presumptively eligible" for allowance rebates under H.R. 2454 ["presumptive eligibility" screened out industries that did not have a significant exposure to foreign competition]. Of these, 12 are in the chemicals sector, 4 are in the paper sector, 13 are in the nonmetallic minerals sector (e.g., cement and glass manufacturers), and 8 are in the primary metals sector (e.g., aluminum and steel manufacturers). Many of these sectors are at or near the beginning of the value chain, and provide the basic materials needed for manufacturing advanced technologies. In addition to these 44 industries, the processing subsectors of a few mineral industries are also likely to be deemed "presumptively eligible." In total, in 2007, the "presumptively eligible" industries accounted for 12 percent of total manufacturing output and*

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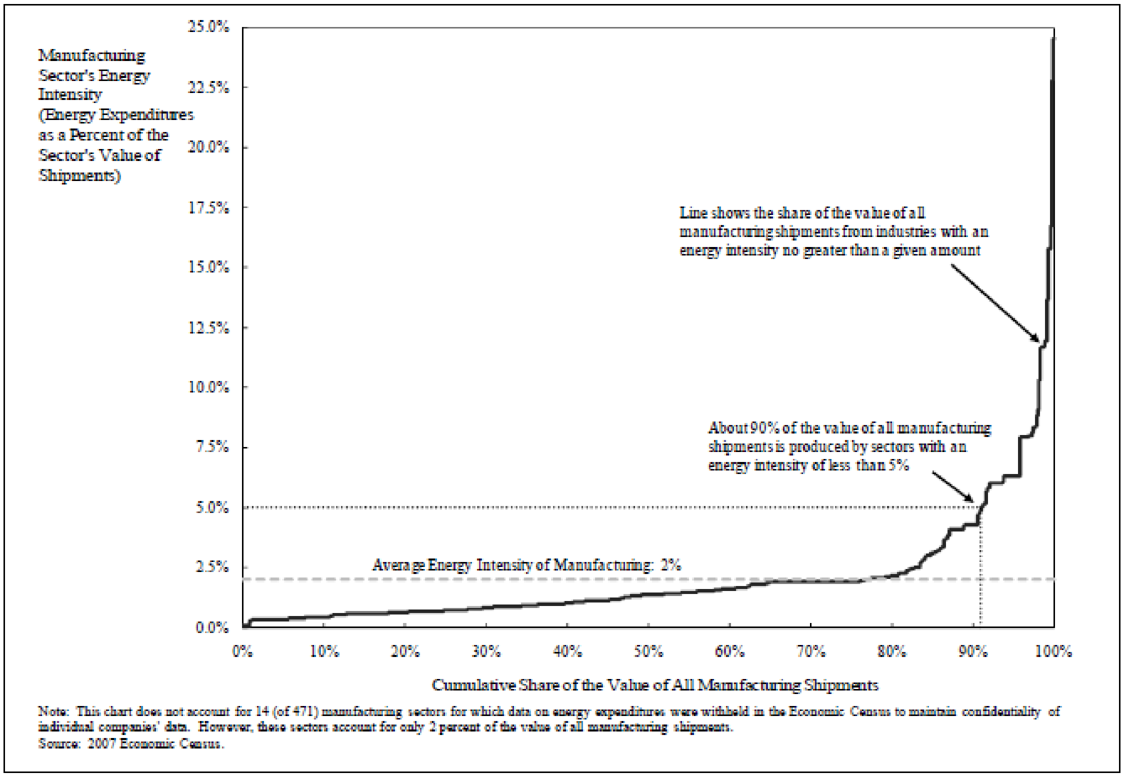
30 "The Effects of H.R.2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," An Interagency Report Responding to a Request from Senators Bayh, Specter, Stabenow, McCaskill, and Brown December 2, 2009.

31 "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 8.

32 "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 8.

employed about 780,000 workers, or about 6 percent of manufacturing employment and half a percent of total U.S. non-farm employment. [Figure 1 shows that] most industrial sectors have energy intensities of less than 5 percent, and will therefore have minimal direct exposure to a climate policy's economic impacts.[33]

Figure 43: Interagency Report (Figure 1)



Source: "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 7.

If we were to use the same criterion for EITE for natural gas, it would imply that an energy-intensive industry was one that would have expenditures on natural gas at the projected industrial price for natural gas greater than 5% of its value of output.

4. Vulnerable Industries are not High Value-Added Industries

A high value-added industry is one in which wage income and profits are a large share of revenues, implying that purchases of other material inputs and energy are a relatively small share. This implies that in a high value-added industry, increases in natural gas prices would have a relatively small impact on overall costs of production. Exactly that pattern is seen in Figure 44, which shows that the industries with the highest energy intensity are low margin

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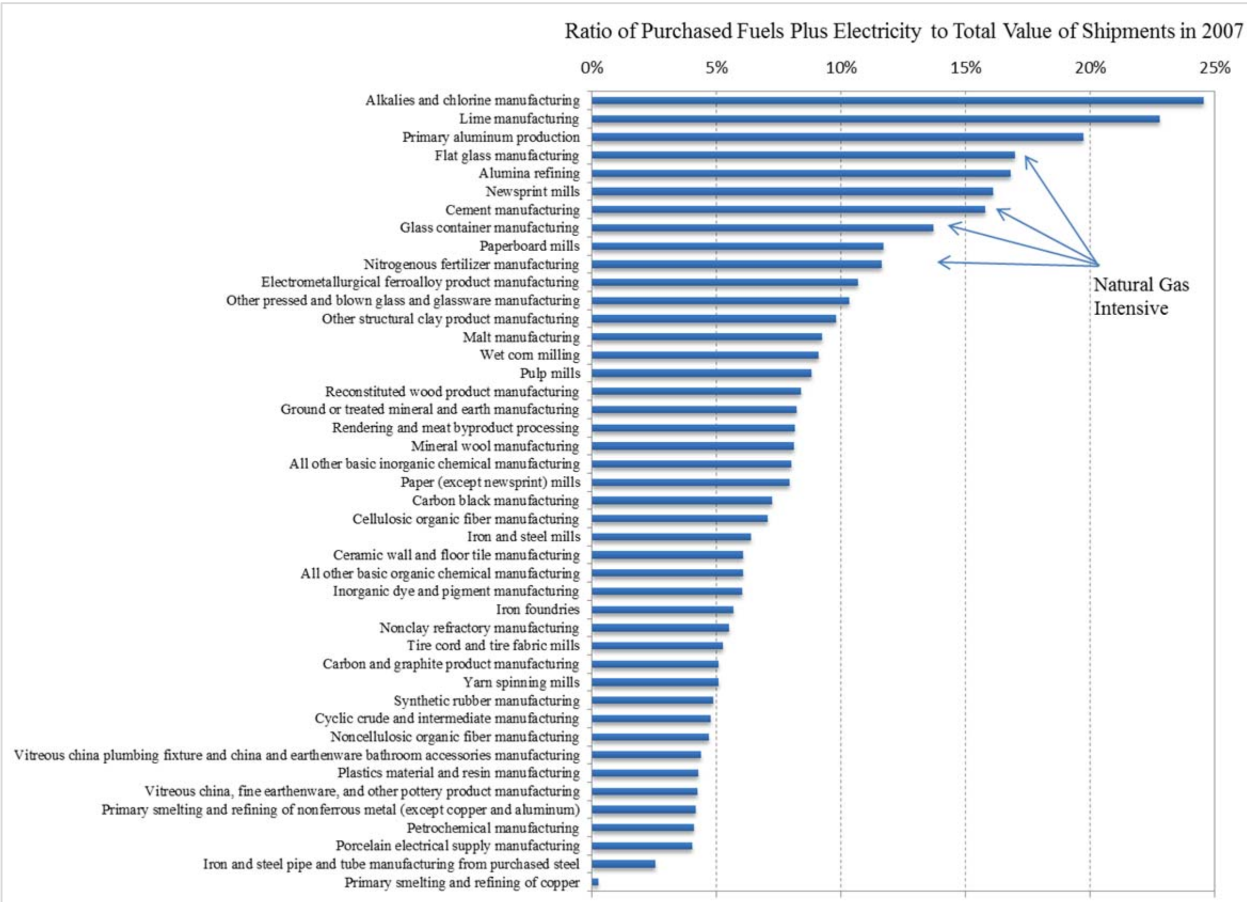
[33] "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 9.

industries that use high heats for refining, smelting, or beneficiation processes, or else they are bulk chemical processes with low value-to-weight ratios and large amounts of natural gas used as a feedstock.

Figure 44: Energy Intensity of Industries "Presumptively Eligible" for Assistance under Waxman-Markey



Source: Based on information from Census.gov. Energy intensity is measured as the value of purchased fuels plus electricity divided by the total value of shipments.

For manufacturing as a whole in 2007,[34] the ratio of value added to the total value of shipments was 78%. In the nitrogenous fertilizer industry, as an example of a natural gas-intensive, trade-exposed industry, the ratio of value added to value of shipments was only 44%. It is also a small industry with a total of 3,920 employees nationwide in 2007.[35] The ratio of value added to value of shipments for the industries that would be classified as EITE under the Waxman-Markey criteria was approximately 41%.[36] Thus there is little evidence that trade-exposed industries that

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[34] The date of the most recent Economic Census that provides these detailed data is the year 2007.

[35] http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk.

[36] Excludes two six-digit NAICS codes for which data was withheld to protect confidentiality, 331411 and 331419. Source: http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk.

would experience the largest cost increases due to higher natural gas prices are high value-added industries.

The Interagency Study similarly observed:

> *On the whole, energy expenditures equal only 2 percent of the value of U.S. manufacturing's output (see Figure 1) and three-quarters of all manufacturing output is from industries with energy expenditures below 2 percent of the value of their output. Thus, the vast majority of U.S. industry will be relatively unaffected by a greenhouse gas cap-and-trade program.*[37]

The same conclusion should apply to the effects of price increases attributable to LNG exports.

5. Impacts on Energy-Intensive Industries at the Plant or 5- to 6-Digit NAICS Level

The issue of EITE industries was investigated exhaustively during Congressional deliberations on climate legislation in the last Congress. In particular, H.R.2454 (the Waxman-Markey bill) set out specific criteria for classification as EITE. A broad consensus developed among analysts that at the 2 to 4-digit level of NAICS classification there were no industries that fit those criteria for EITE, and that only at the 5- to 6-digit level would there be severe impacts on any specific industry.[38] The phrase "deep but narrow" was frequently used to characterize the nature of competitive impacts. Some examples of industries that did fit the criteria for EITE were 311251 (nitrogenous fertilizer) within the 31 (2-digit chemicals) industry and 331111 (iron and steel mills) within the 3311 (4-digit iron and steel) industry. Analysis in this report strongly suggests that competitive impacts of higher natural gas prices attributable to LNG exports will be very narrow, but it was not possible to model impacts on each of the potentially affected sectors.

E. Sensitivities

1. Lost Values from Quota Rents

When scarcity is created there is value associated with supplying an additional unit. In economic terms, a quantity restriction to create this scarcity is called a quota. By enacting a quota, one creates a price difference between the world supply price (netback price) and the domestic price. This generates economic rent referred to as the "quota rent." Mathematically, a quota rent is the quota amount times the difference between the world net back price and the domestic price. A quota rent provides an additional source of revenue to the seller.

The quota levels for the13 scenarios analyzed and discussed in this study correspond to the export volumes assumed in the EIA Study. We assume that the quota rents are held by foreign

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37 "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 7.

38 Richard Morgenstern, *et al.*, RFF Workshop Report.

parties. That is, the rents do not recycle back into the U.S. economy. In this section, we look at how the welfare results would change if the quota rents were recycled back to the U.S.

Figure 45 shows the quota price in 2010 dollars per Mcf for all 13 scenarios determined in the GNGM. The quota price is the marginal price of the quota, or the quota rents divided by the level of exports. The quota price is zero for scenarios that have a non-binding quota constraint. That is, export volumes are less than the quota levels. All of the scenarios under the High EUR and Low EUR cases have binding quota constraints leading to a positive quota price. The quota price is highest in the scenarios in which the domestic natural gas price is the lowest (*i.e.*, the low scenarios for the High EUR outlook). The largest quota price results in the High EUR case with the Low/Slowest export expansion scenario (HEUR_SD_LSS). For this scenario, the quota price is around $3/Mcf.

Figure 45: Quota Price (2010$/Mcf)

Scenario	Quota Price (2010$/Mcf)				
	2015	2020	2025	2030	2035
USREF_SD_LS	1.24	0.52	1.11	1.2	1.62
USREF_SD_LR	1.09	0.52	1.11	1.2	1.62
USREF_D_LS	-	-	-	-	-
USREF_D_LR	-	-	-	-	-
USREF_SD_HS	1.24	0.52	-	0.08	0.67
USREF_SD_HR	0.74	-	-	0.08	0.67
USREF_D_LSS	0.46	-	-	-	-
HEUR_SD_LS	2.23	1.88	2.71	2.69	3.28
HEUR_SD_LR	1.8	1.88	2.71	2.69	3.28
HEUR_SD_HS	2.23	1.88	1.73	1.73	2.47
HEUR_SD_HR	1.8	0.52	1.53	1.73	2.47
HEUR_SD_LSS	2.34	2.63	2.81	2.69	3.28
LEUR_SD_LSS	-	-	-	-	-

Figure 46: Quota Rents (Billions of 2010$)

Scenario	Quota Rents* (Billions of 2010$)				
	2015	2020	2025	2030	2035
USREF_SD_LS	0.41	1.02	2.19	2.37	3.19
USREF_SD_LR	1.08	1.02	2.19	2.37	3.19
USREF_D_LS	-	-	-	-	-
USREF_D_LR	-	-	-	-	-
USREF_SD_HS	0.41	1.02	-	0.32	2.64
USREF_SD_HR	0.73	-	-	0.32	2.64
USREF_D_LSS	0.07	-	-	-	-
HEUR_SD_LS	0.74	3.71	5.34	5.30	6.46
HEUR_SD_LR	1.78	3.71	5.34	5.30	6.46
HEUR_SD_HS	0.74	3.71	6.26	6.82	9.74
HEUR_SD_HR	1.78	2.05	6.03	6.82	9.74
HEUR_SD_LSS	0.38	2.60	5.08	5.30	6.46
LEUR_SD_LSS	-	-	-	-	-

** The quota rents are based on net export volumes.*

The quota rents on the other hand, depend on the price and quantity. Even though the price is the highest under the low export scenarios, as seen in Figure 45, quota rents are the largest for the high export expansion scenarios. Under the high quota rent scenario, HEUR_SD_HR, the average annual quota rents range from $1.8 billion to $9.7 billion. Over the model horizon, 2015 through 2035, maximum total quota rents amount to about $130 billion (Figure 47). This is an important source of additional income that would have potential benefits to the U.S. economy. However, in the event that U.S. companies are unable to capture these rents, this source of additional income would not accrue to the U.S. economy.

Figure 47: Total Lost Values

Scenario	Total Lost Value from 2015-2035 (Billions of 2010$)	Average Annual Lost Value (Billions of 2010$)
USREF_SD_LS	$45.92	$1.84
USREF_SD_LR	$49.25	$1.97
USREF_D_LS	$0.00	$0.00
USREF_D_LR	$0.00	$0.00
USREF_SD_HS	$21.97	$0.88
USREF_SD_HR	$18.45	$0.74
USREF_D_LSS	$0.37	$0.01
HEUR_SD_LS	$107.78	$4.31
HEUR_SD_LR	$112.98	$4.52
HEUR_SD_HS	$136.32	$5.45
HEUR_SD_HR	$132.10	$5.28
HEUR_SD_LSS	$99.16	$3.97
LEUR_SD_LSS	$0.00	$0.00

2. A Larger Share of Quota Rents Increases U.S. Net Benefits

To understand how the macroeconomic impacts (or U.S. net benefits) would change if the quota rents were retained by U.S. companies, we performed sensitivities on two different scenarios – one with high quota price, HEUR_SD_LSS, and the other with high quota rents, HEUR_SD_HR. The sensitivities put an upper bound on the potential range of improvement in the net benefits to the U.S. consumers.

In the sensitivity runs, we assume that quota rents are returned to the U.S. consumers as a lump-sum wealth transfer from foreign entities.

Figure 48 shows the range of welfare changes for the sensitivities of the two scenarios. Under both scenarios, the welfare improves because the quota rents provide additional income to the household in the form of a wealth transfer. Consumers have more to spend on goods and services leading to higher welfare. The welfare in the Low/Slowest scenario improves by more than threefold, while under the High/Rapid scenario the improvement in welfare increases by twofold. The ability to extract quota rents unequivocally benefits U.S. consumers.

Figure 48: Change in Welfare with Different Quota Rents[39]

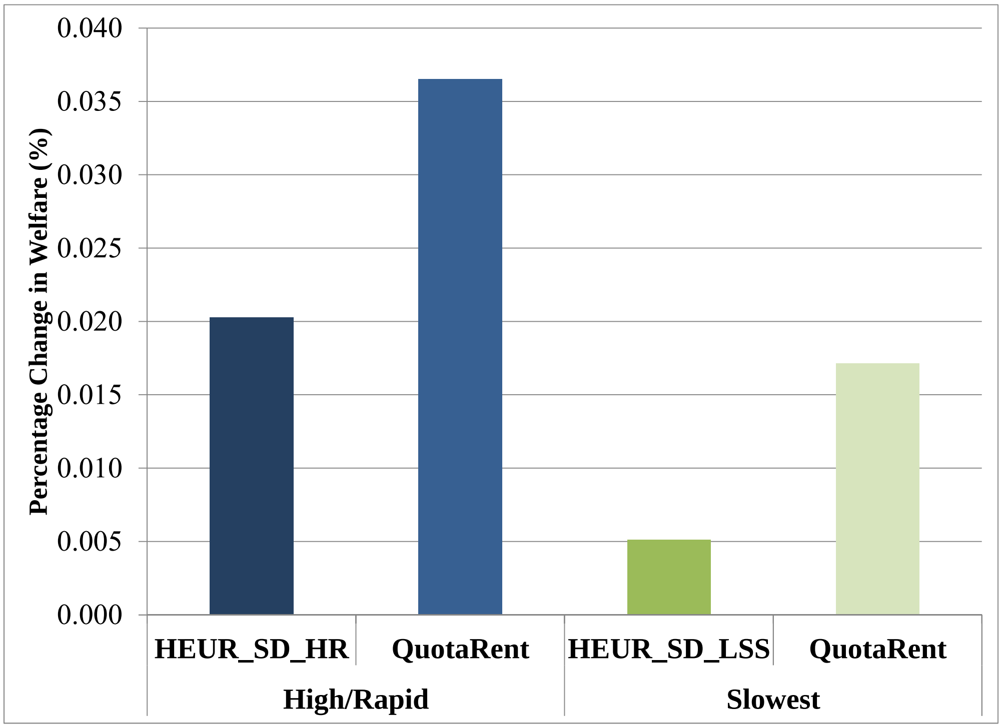

Figure 49 shows the change in impacts on aggregate consumption, GDP, and other household income for different quota rent sensitivities. The additional income from quota rents makes consumers wealthier, leading to increased expenditures on goods and services. This increase in economic activity leads to higher aggregate consumption and GDP. The impacts are highest when allowing for maximum quota rent transfer. The pattern of impacts is the same across the High/Rapid and Low/Slowest scenarios - the only difference is in the magnitude of the effect. The change under the Low/Slowest scenario is relatively smaller because of the smaller amount of transfers compared to the High/Rapid scenario. The consumption change under the maximum quota rent transfer scenario in 2015 is 50% higher than the scenario with no quota rent transfer. In this optimistic scenario, consumption changes are always positive throughout the model horizon for both scenarios. The charts below also highlight changes in other household incomes that add to GDP. While all other income source changes remain the same, only the net transfers change. As quota rents increase so does the change in net transfers leading to higher real income. As a result, higher quota rents lead to more imports, more consumption, higher GDP, and ultimately greater well-being of U.S. consumers.

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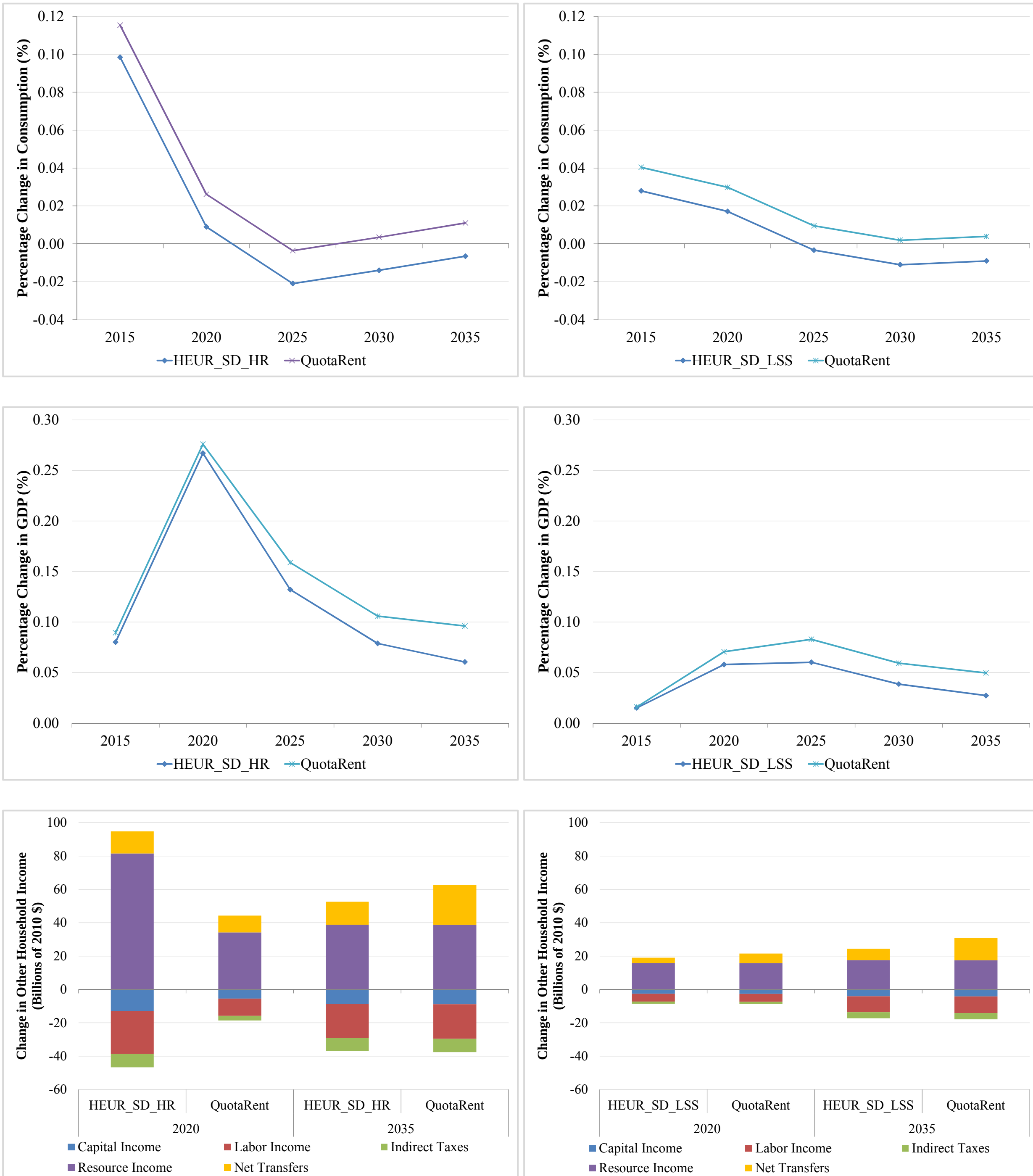
[39] Welfare is calculated as a single number that represents in present value terms the amount that households are made better (worse) off over the entire time horizon from 2015 to 2035.

Figure 49: Macroeconomic Impacts for the High EUR – High/Rapid and Low/Slowest Scenario Sensitivities



VII. CONCLUSIONS

NERA developed a Global Natural Gas Model ("GNGM") and a general equilibrium model of the U.S. economy ("N$_{ew}$ERA Model") to evaluate feasible levels of LNG exports and their impacts on the U.S. economy. These two models allowed us to determine feasible export levels, characterize the international gas market conditions, and evaluate overall macroeconomic effects. Given the wide range in export expansion outcomes, it is not surprising to find great variation in the macroeconomic impacts and natural gas market changes. Nevertheless, several observations may be distilled from the patterns that emerged.

A. LNG Exports Are Only Feasible under Scenarios with High International Demand and/or Low U.S. Costs of Production

Under status quo conditions in the world and the U.S. (U.S. Reference and International Reference cases) there is no feasible level of exports possible from the U.S. Under the low natural price case (High Shale EUR), LNG exports from the U.S. are feasible. However, under a low shale gas outlook (Low Shale EUR), international demand has to increase along with a tightening of international supply for the U.S. to be an LNG exporter.

B. U.S. Natural Gas Prices Do Not Rise to World Prices

LNG exports will not drive the price of domestic natural gas to levels observed in countries that are willing to pay oil parity-based prices for LNG imports. U.S. exports will drive prices down in regions where U.S. supplies are competitive so that even export prices will come down at the same time that U.S. prices will rise.

Moreover, basis differentials due to transportation costs from the U.S. to high-priced regions of the world will still exist, and U.S. prices will never get closer to those prices than the cost of liquefaction plus the cost of transportation to and regasification in the final destination. Thus even in the scenarios with no binding export levels, the wellhead price in the U.S. is below the import price in Japan, where the U.S. sends some of its exports.

The largest change in international natural gas prices in 2015 and 2025 is about $0.33/MMBtu and $1/MMBtu, respectively. These increases occur only in highly stressed conditions or when global markets are willing to take the full quantities of export volumes at prices above marginal production cost in the U.S. plus liquefaction, transportation, and regasification costs incurred to get the LNG to market.

C. Consumer Well-being Improves in All Scenarios

The macroeconomic analysis shows that there are consistent net economic benefits across all the scenarios examined and that the benefits generally become larger as the amount of exports increases. These benefits are measured most accurately in a comprehensive measure of economic welfare of U.S. households that takes into account changes in their income from all sources and the cost of goods and services they buy. This measure gives a single indicator of relative overall well-being of the U.S. population, and it consistently ranks all the scenarios with

LNG exports above the scenario with No-Exports. Welfare improvement is highest under the high export volume scenarios because U.S. consumers benefit from an increase in wealth transfer and export revenues.

D. There Are Net Benefits to the U.S.

A related measure that shows how economic impacts are distributed over time is GDP. Like welfare, GDP also increases as a result of LNG exports. The most dramatic changes are in the short term, when investment in liquefaction capacity adds to export revenues and tolling charges to grow GDP. Under the Reference case, GDP increases could range from $5 billion to $20 billion. Under the High Shale case, GDP in 2020 could increase by $10 billion to $47 billion. Under the Low Shale case, GDP in 2020 could increase by $4.4 billion. Every scenario shows improvement in GDP over the No-Exports cases although in the long run the impact on GDP is relatively smaller than in the short run.

Although the patterns are not perfectly consistent across all scenarios, the increase in investment for liquefaction facilities and increased natural gas drilling and production provides, in general, near-term stimulus to the economy. At the same time, higher energy costs do create a small drag on economic output in the U.S. so that total worker compensation declines.

E. There Is a Shift in Resource Income between Economic Sectors

The U.S. has experienced many changes in trade patterns as a result of changing patterns of comparative advantage in global trade. Each of these has had winners and losers. Grain exports raised the income of farmers and transferred income from U.S. consumers to farmers, steel imports lowered the income of U.S. steel companies and lowered costs of steel for U.S. manufacturing, etc.

The U.S. economy will experience some shifts in output by industrial sectors as a result of LNG exports. Compared to the No-Exports case, incomes of natural gas producers will be greater, labor compensation in the natural gas sector will increase while other industrial sector output and labor compensation decreases. The natural gas sector could experience an increase in production by 0.4 Tcf to 1.5 Tcf by 2020 and 0.3 Tcf to 2.6 Tcf by 2035 to support LNG exports. The LNG exports could lead to an average annual increase in natural export revenues of $10 billion to $30 billion. Impacts on sectoral output vary. Manufacturing sector output decreases by less than 0.4% while EIS and electric sector output impacts could be about 1% in 2020 when the natural gas price is the highest. Changes in industry output and labor compensation are very small. Even energy-intensive sectors experience changes of 1% or less in output and labor compensation during the period when U.S. natural gas prices are projected to rise more rapidly than in a No-Exports case.

Harm is likely to be confined to narrow segments of the industry, and vulnerable industries are not high value-added industries. The electricity sector, energy-intensive sector, and natural gas-dependent goods and services producers will all be impacted by price rises. Conversely, natural gas suppliers will benefit. Labor wages will likewise decrease or increase, respectively, depending on the sector of the economy. The overall impact on the economy depends on the tradeoff between these sectors.

In terms of natural gas-dependent production, producers switch to cheaper fuels or use natural gas more efficiently as natural gas prices rise and production overall is reduced. Reductions in tax revenues are directly related to changes in sectoral output. Industrial output declines the most in scenarios that have the highest increase in natural gas and fuel costs.

The costs and benefits of natural gas price increases are shifted in two ways. Costs and benefits experienced by industries do not remain with the companies paying the higher energy bills or receiving higher revenues. Part of the cost of higher energy bills will be shifted forward onto consumers, in the form of higher prices for goods being produced. The percentage of costs shifted forward depends on two main factors: first, how demand for those goods responds to increases in price, and second, whether there are competitors who experience smaller cost increases. The remainder of the cost of higher energy bills is shifted backwards onto suppliers of inputs to those industries, to their workers, and to owners of the companies. As each supplier in the chain experiences lower revenue, its losses are also shifted back onto workers and owners.

Gains from trade are shifted in the same way. Another part of the increased income of natural gas producers comes from foreign sources. This added revenue from overseas goes immediately to natural gas producers and exporters but does not come from U.S. consumers. Therefore, it is a net benefit to the U.S. economy and is also shifted back to the workers and owners of businesses involved directly and indirectly in natural gas production and exports.

In the end, all the costs and benefits of any change in trade patterns or prices are shifted back to labor and capital income and to the value of resources in the ground, including natural gas resources. One of the primary reasons for development of computable general equilibrium models like N_{ew}ERA is to allow analysts to estimate how impacts are shifted back to the different sources of income and their ultimate effects on the economy at large. In conclusion, the range of aggregate macroeconomic results from this study suggests that LNG export has net benefits to the U.S. economy.

APPENDIX A - TABLES OF ASSUMPTIONS AND NON-PROPRIETARY INPUT DATA FOR GLOBAL NATURAL GAS MODEL

A. Region Assignment

Figure 50: Global Natural Gas Model Region Assignments

Region	Countries
Africa	Algeria, Angola, Egypt, Equatorial Guinea, Ghana, Libya, Morocco, Mozambique, Nigeria, Tunisia
Canada	Canada
China/India	China, Hong Kong, India
Central and South America	Andes, Argentina, Bolivia, Brazil, Central America and Caribbean, Chile, Dominican Republic, Mexico, Peru, Southern Cone, Trinidad & Tobago, Uruguay, Venezuela
Europe	Albania, Austria, Belgium, Croatia, Denmark, Estonia, France, Germany, Greece, Ireland, Italy, Netherlands, North Sea, Norway, Poland, Portugal, Romania, Spain, Sweden, Switzerland, Ukraine, United Kingdom
Former Soviet Union	Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan
Korea/Japan	South Korea, Japan
Middle East	Abu Dhabi, Cyprus, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, Turkey, United Arab Emirates, Yemen
Oceania	Australia, New Zealand, Papua New Guinea
Sakhalin	Sakhalin Island
Southeast Asia	Brunei, Indonesia, Malaysia, Myanmar, Singapore, Taiwan, Thailand
U.S.	Puerto Rico, United States

B. EIA IEO 2011 Natural Gas Production and Consumption

Figure 51: EIA IEO 2011 Natural Gas Production (Tcf)

	2010	2015	2020	2025	2030	2035
Africa	7.80	9.70	11.10	12.20	13.30	14.10
Canada	6.10	7.00	7.70	8.30	8.70	9.00
China/India	4.60	5.60	6.70	8.00	9.60	9.70
C&S America	6.80	7.90	8.30	9.20	10.50	11.70
Europe	9.50	8.10	7.40	7.50	7.90	8.30
FSU	28.87	30.05	32.12	34.89	37.77	39.94
Korea/Japan	0.20	0.20	0.20	0.20	0.20	0.20
Middle East	16.30	19.70	22.40	24.60	26.70	28.80
Oceania	2.10	2.60	3.10	3.80	4.80	5.70
Sakhalin	0.43	0.45	0.48	0.51	0.53	0.56
Southeast Asia	9.30	10.00	10.70	11.60	12.60	13.40
U.S.	21.10	22.40	23.40	24.00	25.10	26.40
World	113.10	123.70	133.60	144.80	157.70	167.80

Figure 52: EIA IEO 2011 Natural Gas Consumption (Tcf)

	2010	2015	2020	2025	2030	2035
Africa	3.90	4.70	5.90	7.10	8.30	9.10
Canada	3.30	3.50	3.70	4.20	4.60	5.00
China/India	5.70	8.60	10.70	13.10	15.10	16.60
C&S America	6.60	7.40	8.90	10.50	12.20	14.40
Europe	19.20	19.80	20.40	20.90	22.00	23.20
FSU	24.30	24.30	24.50	24.90	25.80	26.50
Korea/Japan	5.00	5.20	5.30	5.70	5.90	5.90
Middle East	12.50	14.70	17.00	19.10	21.30	24.00
Oceania	1.20	1.30	1.50	1.80	2.00	2.20
Sakhalin	0.00	0.00	0.00	0.00	0.00	0.00
Southeast Asia	7.40	8.50	10.00	12.00	13.90	15.30
U.S.	23.80	25.10	25.30	25.10	25.90	26.50
Total World	112.90	123.10	133.20	144.40	157.00	168.70

C. Pricing Mechanisms in Each Region

1. Korea/Japan

Korea/Japan was assumed to continue to rely upon LNG to meet its natural gas demand. LNG was assumed to continue to be supplied under long-term contracts with index pricing tied to crude oil prices. It was assumed that with time, supplier competition would result in some softening in the LNG pricing relative to crude.[40] This Reference case assumes some growth in Korea/Japan demand but does not incorporate significant shifts away from nuclear energy to natural gas-fired generation.

2. China/India

LNG pricing for China/India is also assumed to be linked to crude oil prices but at a discount to Korea/Japan. The discount was intended to reflect that China/India, although short of natural gas supplies, have other sources of natural gas that LNG complements. As a result, we assumed that China/India would have some additional market leverage in negotiating contracting terms.

3. Europe

Europe receives natural gas from a variety of sources. The prices of some supplies are indexed to petroleum prices. Other sources are priced based upon regional gas-on-gas competition. In our analysis, we assumed that European natural gas prices would reflect a middle point with prices not tied directly either to petroleum or to local natural gas competition. We assumed that European prices would remain above the pricing levels forecast for North America but not as high as in Asia. Europe was also assumed to remain dependent upon imported supplies of natural gas to meet its moderately growing demand.

4. United States

The United States was assumed to follow the forecast for supply and demand and pricing as presented in the EIA's AEO 2011 Reference case.

5. Canada

The analysis assumed that Canada is part of an integrated North American natural gas market. As a consequence, Canadian pricing is linked to U.S. prices, and Canadian prices relate by a basis differential to U.S. prices. We assumed that Canadian production was sufficient to meet Canadian demand plus exports to the United States as forecast in the EIA AEO 2011. We did not allow for Canadian exports of LNG in the Reference case. Also, we held exports to the United States constant across different scenarios so as to be able to eliminate the secondary impacts of changing imports on the economic impacts of U.S. LNG on the U.S. economy.

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[40] This is consistent with the IEO WEO 2011, which forecasts the LNG to Crude index will decline from 82% to 63% between now and 2035.

6. Africa, Oceania, and Southeast Asia

These three regions were assumed to produce natural gas from remote locations. The analysis assumed that these natural gas supplies could be produced economically today at a price between $1 and $2/MMBtu. The EIA's IEO 2011 was used as the basis for forecasting production volumes.

7. Middle East

Qatar is assumed to be the low-cost producer of LNG in the world. It is assumed that although Qatar has vast natural gas resources, it decides to continue to limit its annual LNG exports to 4.6 Tcf during the forecast horizon.

8. Former Soviet Union

The FSU was assumed to grow its natural gas supply at rates that far exceed its domestic demand. The resulting excess supplies were assumed to be exported mostly to Europe and, to a lesser degree, to China/India.

9. Central and South America

Central and South America was assumed to produce sufficient natural gas to meet its growing demand in every year during the forecast horizon. The region also has the potential for LNG exports that the model considered in determining worldwide LNG flows.

Figure 53: Projected Wellhead Prices ($/MMBtu)

	2010	2015	2020	2025	2030	2035
Africa	$1.75	$1.89	$2.09	$2.31	$2.55	$2.81
Canada	$3.39	$3.72	$4.25	$5.20	$5.64	$6.68
China/India	$12.29	$12.86	$13.00	$13.25	$13.57	$13.51
C&S America	$2.00	$2.16	$2.39	$2.64	$2.91	$3.22
Europe	$9.04	$9.97	$10.80	$11.95	$12.39	$13.23
FSU	$4.25	$4.60	$5.08	$5.61	$6.19	$6.84
Korea/Japan	$14.59	$15.30	$15.47	$15.79	$16.19	$16.11
Middle East	$1.25	$1.35	$1.49	$1.65	$1.82	$2.01
Oceania	$1.75	$1.89	$2.09	$2.31	$2.55	$2.81
Sakhalin	$1.25	$1.35	$1.49	$1.65	$1.82	$2.01
Southeast Asia	$2.00	$2.16	$2.39	$2.64	$2.91	$3.22
U.S.	$3.72	$3.83	$4.28	$5.10	$5.48	$6.36

Source: U.S. wellhead prices are from EIA AEO 2012 Early Release.

Figure 54: Projected City Gate Prices ($/MMBtu)

	2010	2015	2020	2025	2030	2035
Africa	$2.75	$2.89	$3.09	$3.31	$3.55	$3.81
Canada	$4.79	$5.12	$5.65	$6.60	$7.04	$8.08
China/India	$13.79	$14.36	$14.50	$14.75	$15.07	$15.01
C&S America	$4.50	$4.66	$4.89	$5.14	$5.41	$5.72
Europe	$10.04	$10.97	$11.80	$12.95	$13.39	$14.23
FSU	$5.25	$5.60	$6.08	$6.61	$7.19	$7.84
Korea/Japan	$15.09	$15.80	$15.97	$16.29	$16.69	$16.61
Middle East	$4.08	$4.18	$4.32	$4.48	$4.65	$4.84
Oceania	$3.25	$3.39	$3.59	$3.81	$4.05	$4.31
Sakhalin	$3.75	$3.85	$3.99	$4.15	$4.32	$4.51
Southeast Asia	$3.00	$3.16	$3.39	$3.64	$3.91	$4.22
U.S.	$4.72	$4.83	$5.28	$6.10	$6.48	$7.36

D. Cost to Move Natural Gas via Pipelines

Figure 55: Cost to Move Natural Gas through Intra- or Inter-Regional Pipelines ($/MMBtu)

From	To	Cost
Africa	Africa	$1.00
Africa	Europe	$1.00
Canada	Canada	$1.20
Canada	U.S.	$1.20
China/India	China/India	$1.50
FSU	FSU	$1.00
FSU	Europe	$1.00
FSU	China-India	$1.00
U.S.	U.S.	$1.00
U.S.	Canada	$1.00
C&S America	C&S America	$2.50
Middle East	Middle East	$2.83
Oceania	Oceania	$1.50
Korea/Japan	Korea/Japan	$0.50
Europe	Europe	$1.00
Sakhalin	Sakhalin	$0.50
Southeast Asia	Southeast Asia	$1.00

E. LNG Infrastructures and Associated Costs

1. Liquefaction

The world liquefaction plants data is based upon the International Group of LNG Importers' ("GIIGNL") 2010 LNG Industry report. The dataset includes 48 existing liquefaction facilities worldwide, totaling 13.58 Tcf of export capacity. The future liquefaction facility dataset, based upon *LNG Journal* (October 2011),[41] includes 32 LNG export projects and totals 10.59 Tcf of planned export capacity. This dataset covers worldwide liquefaction projects from 2011 to 2017. Beyond 2017, each region's liquefaction capacity is assumed to grow at the average annual growth rate of its natural gas supply.[42]

[41] LNG Journal, Oct 2011. Available at: http://lngjournal.com/lng/.

[42] Rates are adopted from IEO 2011.

The liquefaction cost per MMBtu can be broken down into three components:

1. An operation and maintenance cost of $0.16;
2. A capital cost that depends on the location of the facility; and
3. A fuel use cost that varies with natural gas prices over time.

To derive the capital cost per MMBtu, we obtained a set of investment costs per million metric tons per annum ("MMTPA") by region (Figure 56).[43] The U.S.'s investment cost per MMTPA is competitive because most domestic projects convert existing idle regasification facilities to liquefaction facilities. This implies a 30% to 40% cost savings relative to greenfield projects. Offshore LNG export projects are more costly, raising the investment costs per unit of capacity in Southeast Asia and Oceania.

Figure 56: Liquefaction Plants Investment Cost by Region ($millions/ MMTPA Capacity)

	$Millions/MMTPA	Capital Cost ($/MMBtu produced)
Africa	$1,031	$3.05
Canada	$1,145	$3.39
C&S America	$802	$2.37
Europe	$802	$2.37
FSU	$802	$2.37
Middle East	$859	$2.54
Oceania	$1,317	$3.90
Sakhalin	$802	$2.37
Southeast Asia	$1,145	$3.39
U.S.	$544	$1.61

The total investment cost is then annualized assuming an average plant life of 25 years and a discount rate of 10%. The capital cost per MMBtu of LNG produced is obtained after applying a 72% capacity utilization factor to the capital cost per MMBtu of LNG capacity. Figure 57 shows the liquefaction fixed cost component in $/MMBtu LNG produced.

$$\text{Equivalent Annual Cost} = \frac{\text{Asset Price} \times \text{Discount Rate}}{1-\left(1+\text{Discount Rate}\right)^{-\text{Number of Periods}}}$$

43 From Paul Nicholson, a Marsh & McLennan company colleague (NERA is a subsidiary of Marsh & McClennan).

In the liquefaction process, 9% of the LNG is burned off. This fuel use cost is priced at the wellhead and included in the total liquefaction costs.

Figure 57: Liquefaction Costs per MMBtu by Region, 2010-2035

	2010	2015	2020	2025	2030	2035
Africa	$3.37	$3.38	$3.40	$3.42	$3.44	$3.46
Canada	$3.85	$3.88	$3.93	$4.02	$4.06	$4.15
C & S America	$2.71	$2.73	$2.75	$2.77	$2.79	$2.82
Europe	$3.35	$3.43	$3.50	$3.61	$3.65	$3.72
FSU	$2.65	$2.65	$2.67	$2.68	$2.70	$2.71
Middle East	$2.81	$2.82	$2.84	$2.85	$2.87	$2.88
Oceania	$4.22	$4.23	$4.25	$4.27	$4.29	$4.31
Sakhalin	$2.65	$2.65	$2.67	$2.68	$2.70	$2.71
Southeast Asia	$3.73	$3.74	$3.76	$3.79	$3.81	$3.84
U.S.	$2.13	$2.14	$2.18	$2.25	$2.28	$2.34

2. Regasification

The world regasification plants data is based upon the GIIGNL's annual LNG Industry report, 2010. The dataset includes 84 existing regasification facilities worldwide, totaling to a 28.41 Tcf annual import capacity. Korea and Japan together own 12.58 Tcf or 44% of today's world regasification capacities. The GNGM future regasification facility database includes data collected from multiple sources: the GLE Investment Database September 2011, LNG journal Oct 2011, and GIIGNL's 2010 LNG Industry report. It includes 46 LNG import projects, totaling to 12.12 Tcf of planned import capacity, and covers regasification projects from 2011 to 2020 worldwide. Beyond 2020, each region's regasification capacity is assumed to grow at the average annual growth rate of its natural gas demand.[44]

LNG regasification cost can also be broken down into three components: an operation and maintenance cost of $0.20/MMBtu, a fixed capital cost of $0.46/MMBtu, and a fuel use cost that varies with natural gas demand prices by region and time. The capital cost assumes a 40% capacity utilization factor, and the fuel use component assumes a 1.5% LNG loss in regasification. LNG regasification cost in GNGM is shown in Figure 58.

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[44] Rates adopted from IEO 2011.

Figure 58: Regasification Costs per MMBtu by Region 2010-2035

	2010	2015	2020	2025	2030	2035
C&S America	$0.73	$0.73	$0.73	$0.74	$0.74	$0.75
Canada	$0.73	$0.74	$0.75	$0.76	$0.77	$0.78
China/India	$0.87	$0.88	$0.88	$0.88	$0.89	$0.89
Europe	$0.81	$0.83	$0.84	$0.86	$0.86	$0.87
FSU	$0.74	$0.75	$0.75	$0.76	$0.77	$0.78
Korea/Japan	$0.89	$0.90	$0.90	$0.91	$0.91	$0.91
Middle East	$0.72	$0.72	$0.73	$0.73	$0.73	$0.73
Southeast Asia	$0.71	$0.71	$0.71	$0.72	$0.72	$0.72
U.S.	$0.73	$0.73	$0.74	$0.75	$0.76	$0.77

3. Shipping Cost

GNGM assumes that the shipping capacity constraint is non-binding. There are sufficient LNG carriers to service any potential future route in addition to existing routes.

Shipping cost consists of a tanker cost and a LNG boil-off cost, both of which are a function of the distance between the export and import regions. An extra Panama Canal toll of 13 cents roundtrip is applied to gulf-Asia Pacific shipments.[45] Tanker costs are based on a $65,000 rent per day and average tanker speed of 19.4 knots. Fuel use costs assume a 0.15% per day boil off rate and an average tanker capacity of 149,000 cubic meters of LNG. LNG boil-off cost is valued at city gate prices in importing regions. Shipping distances for existing routes are based upon the GIIGNL's 2010 LNG Industry report while distances for potential routes are calculated with the Sea Rates online widget.[46]

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45 $0.13 roundtrip toll calculated based upon a 148,500 cubic meter tanker using approved 2011 rates published at http://www.pancanal.com/eng/maritime/tolls.html.

46 http://www.searates.com/reference/portdistance/.

Figure 59: 2010 Shipping Rates ($/MMBtu)

	Canada	China/ India	C&S America	Europe	Korea/ Japan	Oceania	SE Asia	U.S.
Africa		$1.76	$1.44	$0.46	$2.60		$1.70	$2.60
Canada		$1.51	$1.53		$1.23		$1.55	
China/ India								$2.81
C&S America	$1.53	$2.22	$1.26	$1.39	$2.73			$1.54
Europe								$1.27
FSU			$2.15			$2.39	$2.44	$1.17
Korea/ Japan								$2.54
Middle East		$0.96	$2.36	$1.30	$1.61		$1.15	$2.16
Oceania		$0.74	$2.38		$0.90		$0.63	$2.41
Sakhalin		$0.48			$0.26		$0.84	$2.50
Southeast Asia		$0.52			$0.66		$0.32	$2.63
U.S.		$2.81	$1.53	$1.27	$2.54		$2.61	

The Gulf Coast has a comparative disadvantage in accessing the Asia pacific market due to the long shipping distances and Panama Canal tolls.

4. LNG Pipeline Costs

A pair of pipeline transport costs is also included in LNG delivery process to account for the fact that pipelines are necessary to transport gas from wellheads to liquefaction facilities in supply regions and from regasification facilities to city gates in demand regions.

Figure 60: Costs to Move Natural Gas from Wellheads to Liquefaction Plants through Pipelines ($/MMBtu)

Region	Cost
Africa	$1.00
Canada	$0.70
China/India	$1.50
C&S America	$0.50
Europe	$1.00
FSU	$1.00
Korea/Japan	$1.00
Middle East	$1.42
Oceania	$0.50
Sakhalin	$0.50
Southeast Asia	$1.00
U.S.	$1.00

Figure 61: Costs to Move Natural Gas from Regasification Plants to City Gates through Pipelines ($/MMBtu)

Region	Cost
Africa	$1.00
Canada	$0.50
China/India	$1.50
C&S America	$0.50
Europe	$1.00
FSU	$1.00
Korea/Japan	$0.50
Middle East	$1.42
Oceania	$0.50
Sakhalin	$0.50
Southeast Asia	$1.00
U.S.	$1.00

5. Total LNG Costs

Costs involved in exporting LNG from the Gulf Coast to demand regions are aggregated in Figure 62. The largest cost components are liquefaction and shipping.

Figure 62: Total LNG Transport Cost, 2015 ($/MMBtu)

	China/India	Europe	Korea/Japan
Regas to city gate pipeline cost	$1.50	$1.00	$0.50
Regas cost	$0.88	$0.83	$0.90
Shipping cost	$2.87	$1.33	$2.60
Liquefaction cost	$2.14	$2.14	$2.14
Wellhead to liquefaction pipeline cost	$1.00	$1.00	$1.00
Total LNG transport cost	$8.39	$6.30	$7.14

F. Elasticity

1. Supply Elasticity

All regions are assumed to have a short-run supply elasticity of 0.2 in 2010 and a long-run elasticity of 0.4 in 2035. Elasticities in the intermediate years are interpolated with a straight line method. There are two exceptions to this rule.

The U.S. supply elasticity is computed based upon the price and production fluctuations under different scenarios in the EIA Study. The median elasticity in 2015 and 2035 is recorded and elasticities for the other years are extrapolated with a straight line method.

After numerous test runs, we found that African supply elasticity is appropriately set at 0.1 for all years. Supply elasticity in GNGM is:

Figure 63: Regional Supply Elasticity

	2010	2015	2020	2025	2030	2035
Africa	0.10	0.10	0.10	0.10	0.10	0.10
U.S.	0.17	0.24	0.33	0.46	0.65	0.90
All other regions	0.20	0.23	0.26	0.30	0.35	0.40

2. Demand Elasticity

All regions are assumed to have a short run demand elasticity of -0.10 in 2010 and a long run demand elasticity of -0.20 in 2035 except the U.S. The U.S. demand elasticity is derived based on average delivered price and consumption fluctuations reported in the EIA Study.

Figure 64: Regional Demand Elasticity

	2010	2015	2020	2025	2030	2035
U.S.	-0.33	-0.36	-0.39	-0.42	-0.46	-0.50
All other regions	-0.10	-0.11	-0.13	-0.15	-0.17	-0.20

G. Adders from Model Calibration[47]

Figure 65: Pipeline Cost Adders ($/MMBtu)

Exporters	Importers	2010	2015	2020	2025	2030	2035
Africa	Europe	$7.43	$8.23	$8.88	$9.83	$10.03	$10.62
Canada	Canada	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20
Canada	U.S.	$0.30	$0.12				
FSU	China/India	$8.71	$8.93	$8.58	$8.30	$8.03	$7.31
FSU	Europe	$4.88	$5.47	$5.83	$6.46	$6.32	$6.52
Sakhalin	Sakhalin	$2.04	$2.04	$2.04	$2.04	$2.04	$2.04

47 Appendix B provides details on the generation of cost adders in GNGM.

Figure 66: LNG Cost Adders Applied to Shipping Routes ($/MMBtu)

Exporter	Importer	2010	2015	2020	2025	2030	2035
Africa	China/India	$3.59	$3.97	$3.89	$3.89	$3.93	$3.57
Africa	Europe	$1.73	$2.50	$3.11	$4.01	$4.18	$4.73
Africa	Korea/Japan	$5.09	$5.60	$5.54	$5.59	$5.70	$5.33
Canada	China/India	$5.91	$2.16	$1.71	$0.90	$0.72	-
Canada	Korea/Japan	$8.54	$4.93	$4.52	$3.77	$3.67	$2.44
C&S America	China/India	$4.06	$4.41	$4.29	$4.25	$4.24	$3.85
C&S America	Europe	$1.73	$2.43	$2.97	$3.78	$3.90	$4.36
C&S America	Korea/Japan	$5.89	$6.37	$6.28	$6.30	$6.37	$5.96
Sakhalin	China/India	$6.64	$7.09	$7.07	$7.16	$7.29	$7.01
Sakhalin	Korea/Japan	$9.19	$9.79	$9.81	$9.96	$10.17	$9.89
Middle East	China/India	$5.05	$5.49	$5.47	$5.55	$5.67	$5.40
Middle East	Europe	$1.55	$2.32	$2.96	$3.88	$4.11	$4.70
Middle East	Korea/Japan	$6.74	$7.31	$7.32	$7.46	$7.65	$7.37
U.S.	China/India	$1.51	$1.86	$1.60	$0.92	$0.80	$0.08
U.S.	Europe	-	$0.61	$1.02	$1.21	$1.21	$1.35
U.S.	Korea/Japan	$4.13	$4.62	$4.40	$3.78	$3.74	$3.00
Oceania	China/India	$4.26	$4.66	$4.58	$4.59	$4.64	$4.29
Oceania	Korea/Japan	$6.44	$6.99	$6.94	$7.01	$7.14	$6.77
Southeast Asia	China/India	$4.21	$4.59	$4.48	$4.46	$4.47	$4.08
Southeast Asia	Korea/Japan	$6.42	$6.94	$6.86	$6.91	$7.00	$6.58

H. Scenario Specifications

Figure 67: Domestic Scenario Conditions

	2010	2015	2020	2025	2030	2035
Reference Case						
Production (Tcf)	21.10	22.40	23.40	24.00	25.10	26.40
Wellhead price ($/MMBtu)	$3.72	$3.83	$4.28	$5.10	$5.48	$6.36
Pipeline imports from Canada (Tcf)	2.33	2.33	1.4	0.74	0.64	0.04
High EUR						
Production (Tcf)	21.21	24.68	26.37	27.52	28.61	30.19
Wellhead price ($/MMBtu)	$3.23	$2.90	$3.15	$3.72	$4.14	$4.80
Pipeline imports from Canada (Tcf)	2.18	2.01	0.87	0.01	-0.18	-0.68
Low EUR						
Production (Tcf)	20.93	19.61	19.88	20.06	21.13	21.67
Wellhead price ($/MMBtu)	$4.54	$5.65	$6.37	$7.72	$8.23	$8.85
Pipeline imports from Canada (Tcf)	2.45	2.66	2.06	1.96	1.93	1.66

Figure 68: Incremental Worldwide Natural Gas Demand under Two International Scenarios (in Tcf of Natural Gas Equivalents)

	2010	2015	2020	2025	2030	2035
Demand Shock						
Japan converts nuclear to gas	2.41	3.18	3.41	3.56	3.86	4.19
Supply& Demand Shock						
Japan and Korea convert nuclear to gas and limited international supply expansion	3.82	5.00	5.59	5.88	6.37	6.86

Sources: EIA IEO 2011 Nuclear energy consumption, reference case.

Figure 69: Scenario Export Capacity (Tcf)

	2010	2015	2020	2025	2030	2035
No Export	0	0	0	0	0	0
Low Slow	0	0.37	2.19	2.19	2.19	2.19
High Slow	0	0.37	2.19	4.02	4.38	4.38
Low Rapid	0	1.10	2.19	2.19	2.19	2.19
High Rapid	0	1.10	4.38	4.38	4.38	4.38
Low/Slowest	0	0.18	1.10	2.01	2.19	2.19
No Constraint	∞	∞	∞	∞	∞	∞

Source: EIA Study.

APPENDIX B – DESCRIPTION OF MODELS

A. Global Natural Gas Model

The GNGM is a partial-equilibrium model designed to estimate the amount of natural gas production, consumption, and trade by major world natural gas consuming and/or producing regions. The model maximizes the sum of consumers' and producers' surplus less transportation costs, subject to mass balancing constraints and regasification, liquefaction, and pipeline capacity constraints.

1. Model Calibration

The model is calibrated to match the EIA's IEO and AEO 2011 Reference Case natural gas production, consumption, wellhead, and delivered price forecasts, after adjusting the AEO and IEO production and consumption forecasts so that:

- World supply equaled world demand
- U.S. imports from Canada equaled total U.S. imports as defined by the AEO Reference case, less U.S. LNG imports as defined by the AEO Reference case
- Middle East LNG exports were capped at 4.64 Tcf, which meant that for the Middle East
    - Production ≤ Demand + Min(Liquefaction capacity, LNG export cap)
- FSU pipeline capacity satisfied the expression
    - Production ≤ Demand + pipeline export capacity
- Regasification capacity satisfied the expression for LNG importing regions:
    - Production ≤ Supply + Regasification Capacity
- Sufficient liquefaction capacity exists in LNG exporting regions
    - Production ≤ Demand + liquefaction capacity + pipeline export capacity

The GNGM assumes that the world natural gas market is composed of a perfectly competitive group of countries with a dominant supplier that limits exports. Therefore, if we simply added the competitive transportation costs to transport gas among regions, the model would not find the market values and would be unable to match the EIA's forecasts because the world natural gas market is not perfectly competitive and at its current scale includes important risks and transaction costs. For example, the city gate prices in the Korea/Japan region represent not only the cost of delivering LNG to this region but also this region's willingness to pay a premium above the market price to ensure a stable supply of imports.

Therefore to calibrate the GNGM to the EIA's price and volume forecasts, we had to introduce cost adders that represented the real world cost differentials, including these transaction costs. To derive these cost adders, we developed a least-squares algorithm that solved for these adders. The least-squares algorithm minimized the sum of the inter-region pipeline and LNG shipping cost adders subject to matching the EIA natural gas production, consumption, wellhead, and city gate prices for each region (see Appendix A for the resulting cost adders).

These pipeline and LNG shipping cost adders were added to the original pipeline and LNG shipping costs, respectively, to develop adjusted pipeline and LNG shipping costs. The GNGM made use of these adjusted transportation costs in all the model runs.

These adders can be interpreted in several ways consistent with their function in the GNGM:

- As transaction costs that could disappear as the world market became larger and more liquid, in the process shifting downward the demand curve for assured supplies in the regions where such a premium now exists
- As a leftover from long term contracts and therefore a rent to producers that will disappear as contracts expire and are renegotiated
- As a rent taken by natural gas utilities and traders within the consuming regions, that would either continue to be taken within importing countries or competed away if there were more potential suppliers

Under all of these interpretations, the amount of the adder would not be available to U.S. exporters, nor would it be translated into potentially higher netback prices to the U.S.

2. Input Data Assumptions for the Model Baseline

a. GNGM Regions

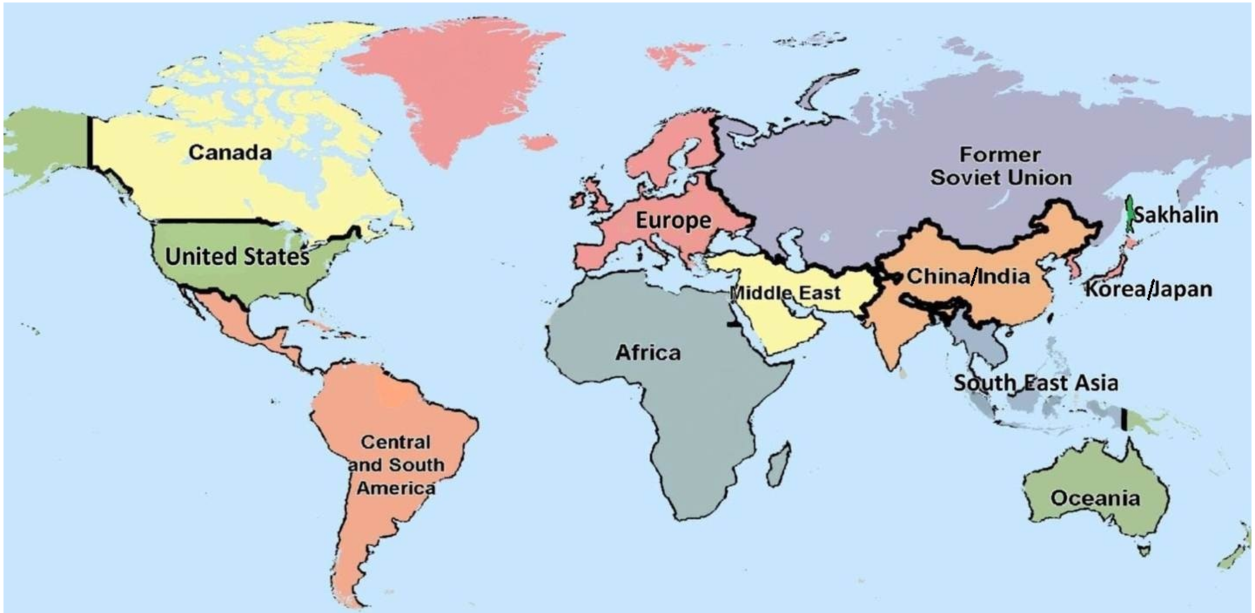
The GNGM regional mapping scheme is largely adapted from the EIA IEO regional definitions with modifications to address the LNG-intensive regions.

- OECD Regions: the OECD region of Americas maps to GNGM regions U.S., Canada and Central and South America; OECD Europe maps to GNGM Europe; OECD Asia maps to GNGM Korea-Japan and Oceania.
- Non-OECD Regions: the non-OECD regions of Eurasia and Europe map to GNGM regions Former Soviet Union and Sakhalin; Non-OECD Asia maps to China-India and Southeast Asia; Middle East maps to GNGM Middle East; Africa to GNGM Africa; Non-OECD Central and South America maps to GNGM Central and South America.
- Sakhalin is a Russian island just north of Japan. All Russian or FSU LNG exports in 2010 were produced in Sakhalin.[48] This island is characterized as a pure supply region with zero demand and adopted as a separate GNGM region from the rest of the FSU for its proximity to the demand regions. Its LNG production in 2010 is set equal to the

[48] "The LNG Industry 2010," GIIGNL. Available at: www.giignl.org/fr/home-page/publications.

FSU's LNG exports in 2010 and grows at a rate of 1.1% per annum for the subsequent years.[49]

Figure 70: Map of the Twelve Regions in the GNGM



b. Time Horizon

GNGM reads in forecast data from each year and outputs the optimized gas trade flows. The model's input data currently covers years 2010 through 2035, but can be readily extended given data availability. For this analysis, we solved the model in five-year time steps starting with 2010.

c. Projected World Natural Gas Production and Consumption

The model's international natural gas consumption and production projections are based upon the IEO 2011 reference case. GNGM assumes four different future U.S. natural gas markets: the AEO 2011 reference case is adopted as the baseline and three other U.S. futures are obtained with the following modifications.

- High Shale EUR: U.S. natural gas production and wellhead prices are replaced by AEO 2011 High Shale EUR projections. All other regions are held constant.
- Low Shale EUR: U.S. natural gas production and wellhead prices are replaced by AEO 2011 Low Shale EUR projections. All other regions are held constant.
- High Economic Growth: U.S. natural gas consumption is replaced by AEO 2011 High Economic Growth projections. All other regions are held constant.

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[49] The 1.1% per annum rate corresponds to IEO 2011 projected Russian natural gas production average annual growth rate for 2008 through 2035.

d. Gas Production and Consumption Prices

NERA has developed a set of world natural gas price projections based upon a number of data sources. The approach focuses on the wellhead price forecasts for net export regions and city gate price forecasts for net import regions. In naturally gas-abundant regions like the Middle East and Africa, the wellhead price is assumed to equal the natural gas extraction cost or lifting cost. City gate prices are estimated by adding a transportation cost to the wellhead prices.

In the major demand markets, natural gas prices are determined on an oil-parity basis using crude oil price forecasts from IEA's WEO 2011. The resultant prices are highly consistent with the relevant historical pipeline import prices[50] and LNG spot market prices as well as various oil and natural gas indices (*i.e.*, JCC, WTI, Henry Hub, AECO Hub indices, and UK National Balancing Point). U.S. wellhead and average city gate prices are adopted from AEO 2011. Canadian wellhead and city gate prices are projected to be $0.35 less than the U.S. prices in the reference case. A region-by-region price forecast description is presented in Section II.

e. Natural Gas Transport Options

Pipelines

GNGM assumes that all intra-regional pipeline capacity constraints are non-binding. Each region is able to transport its indigenously-produced natural gas freely within itself at an appropriate cost.

Four inter-regional pipeline routes are acknowledged in GNGM. The Africa-to-Europe route, including the Greenstream Pipeline, Trans-Mediterranean Pipeline, and Maghreb–Europe Gas Pipeline, is assigned a total capacity of 1.9 Tcf/year (connecting Northern Africa to Spain, Portugal, and Italy). The Turkmenistan–China Gas Pipeline, connecting FSU to China/India, has a maximum discharge of 1.41 Tcf/year. The FSU-Europe pipeline route has a total capacity of 8.3 Tcf/year in 2010 and grows to 10.8 Tcf/year in 2025. Lastly, the U.S.-Canada pipeline route is open and assumed to have unlimited capacity.

LNG Routes

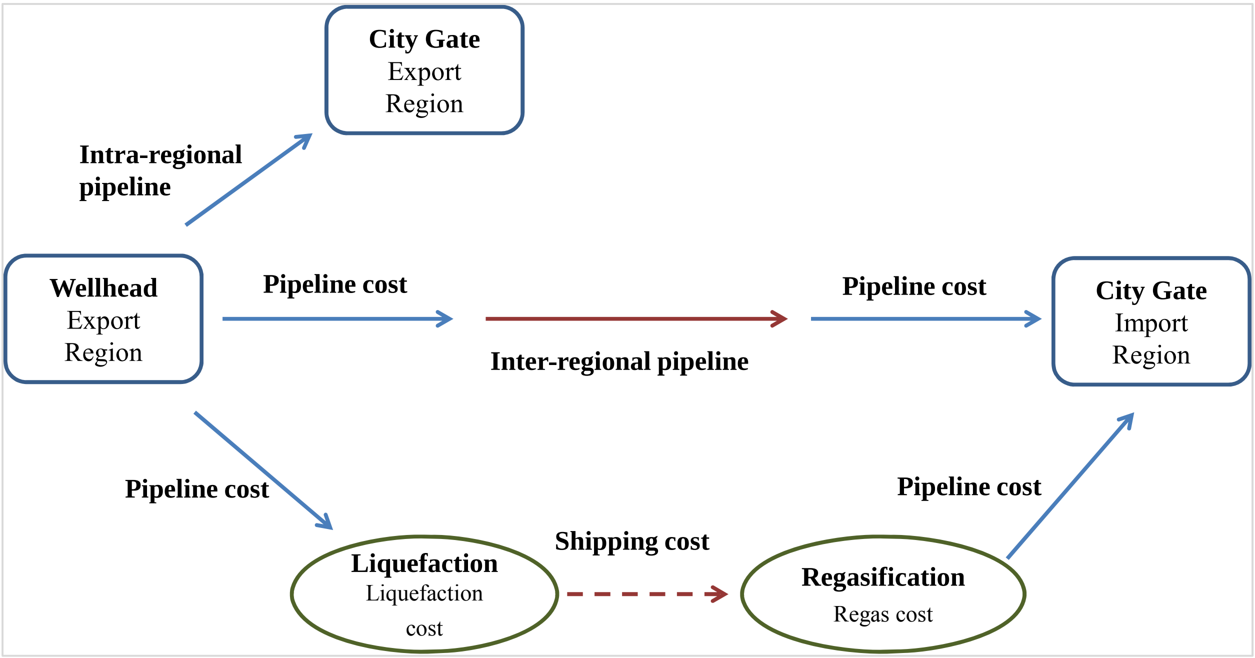
GNGM sets two constraints on LNG transportation. Each export region is subjected to a liquefaction capacity constraint and each import region to a regasification capacity constraint. There are five components in transporting LNG (Figure 71), and capacity constraints on the wellhead to liquefaction pipeline, LNG tankers, and regasification to city gate pipeline are assumed to be non-binding.

LNG transportation costs are generally four to seven times higher than the pipeline alternative since, to satisfy natural gas demand with LNG, shipments incur five segments of costs: 1) pipeline shipping cost to move gas from the wellhead to the liquefaction facility, 2) liquefaction

[50] German BAFA natural gas import border price, Belgium Zeebrugge spot prices, TTF Natural Gas Futures contracts, *etc*.

cost, 3) shipping cost between the liquefaction to regasification facilities, 4) regasification cost and 5) the pipeline shipping cost to move gas from the regasification facility to the city gate terminal in the demand region. A detailed cost breakdown for each leg of this process is presented in Appendix A.

Figure 71: Natural Gas Transport Options



f. Fuel Supply Curves

The supply of natural gas in each region is represented by a CES supply curve (see Equation 1). The supply curve provides a relationship between the supply of gas (Q) and the wellhead price of gas (P). The elasticity of the supply curves dictates how the price of natural gas changes with changes in production.

Equation 1: CES Supply Curve

$$Q(t) / Q_{0,t} = (P(t) / P_{0,t})^{\text{elasticity of supply}}$$

Each supply curve is calibrated to the benchmark data points ($Q_{0.t}$, $P_{0.t}$) for each year t, where the benchmark data points represent those of the EIA's adjusted forecasts.[51] $Q_{0.t}$ represents the EIA's adjusted forecasted quantity of natural gas production for year t, and $P_{0.t}$ represents the EIA's forecasted wellhead price of gas for year t. The elasticity of supply for all regions is included in Figure 63.

[51] See Section IV.B for a discussion of how the EIA's forecasts are adjusted before the GNGM model is calibrated. Note, only quantities are adjusted.

g. Fuel Demand Curves

The demand curve for natural gas has a similar functional form as the supply curve. As with the supply curves, the demand curve in each region is represented by a CES function (see Equation 2). The demand curve provides a relationship between the demand for gas (Q) and the city gate price of gas (P). The demand curves dictate how the price of natural gas changes with changes in demand in each region.

Equation 2: CES Demand Curve

$$Q(t) / Q_{0,t} = (P(t) / P_{0,t})^{\text{elasticity of demand}}$$

Each demand curve is calibrated to the benchmark data points ($Q_{0.t}$, $P_{0.t}$) for each year t, where the benchmark data points represent those of the EIA's adjusted forecasts. $Q_{0.t}$ represents the EIA's adjusted forecasted demand for natural gas for year t and $P_{0.t}$ represents the EIA's forecasted city gate price of gas for year t. The elasticity of demand for all regions except the U.S. is based on the elasticities used in MIT's Emissions Prediction and Policy Analysis ("EPPA") model.[52] For the U.S., the demand elasticity was estimated by using the percentage changes in natural gas demand and city gate prices between the EIA's AEO 2011 Reference scenario and the different shale gas scenarios.

3. Model Formulation

The GNGM is formulated as a non-linear program. The following text describes at a high level the GNGM's non-linear objective function and linear constraints.

Maximize: Consumer Surplus + Producer Surplus – Transportation Costs

Subject to:

$$Supply(s) = \sum_{d} PipeGas(s,d) + LNG(s,d)$$

$$Demand(d) = \sum_{s} PipeGas(s,d) + LNG(s,d)$$

$$\sum_{d} LNG(s,d) \leq LiquefactionCapacity(s)$$

$$\sum_{s} LNG(s,d) \leq RegasificationCapacity(d)$$

52 "The MIT Emissions Prediction and Policy Analysis ("EPPA") Model: Version 4," Sergey Paltsev, John M. Reilly, Henry D. Jacoby, Richard S. Eckaus, James McFarland, Marcus Sarofim, Malcolm Asadoorian and Mustafa Babiker, August 2004.

$$PipeGas(s,d) \leq PipelineCapacity(s,d)$$

$$PipeGas('Canada','USA') = BaselinePipeGas('Canada','USA')$$

Scenario Constraints

* Quota Constraint

$$\sum_{d} LNG('USA',d) \leq Quota$$

* Supply Shock

$$\sum_{d} LNG('Oceania',\mathrm{d}) + LNG('Africa',d) + LNG('SouthEastAsia',d) \\ \leq MaxExports$$

Consumer Surplus = $\int CityGatePrice(d)\ x\ (\frac{Demand(d)}{Demand0(d)})^{(\frac{1}{ElasOfDemand(d)})}$

Producer Surplus= $\int WellheadPrice(s)\ x\ (\frac{Supply(s)}{Supply0(s)})^{(\frac{1}{ElasOfSupply(s)})}$

Transportation Costs =

$$\sum_{s,d} ShipCost(s,d)\ x\ LNG(s,d) \\ + \sum_{s,d} PipeLineCost(s,d)\ x\ PipeGas(s,d) \\ + \sum_{s,d} RegasCost(d)\ x\ LNG(s,d) \\ + \sum_{s,d} LiquefactionCost(s)\ x\ LNG(s,d)$$

where,

LiquefactionCost(s) = Cost to liquefy natural gas in region s + transport the gas from the wellhead to the liquefaction facility within region s.

RegasCost(d) = Cost to re-gasify natural gas in region d + transport the gas from the regasification facility to the city gate within region d.

PipelineCost(s,d) = Cost to transport natural gas along a pipeline from supply region s to demand region d.

ShipCost(s,d) = Cost to ship natural gas from supply region s to demand region d.

Quota = Maximum allowable amount of U.S. LNG exports. This varies by time period and scenario.

The supply curves capture the technological issues (penetration rate, availability and cost) for natural gas in each region. The demand curves for natural gas capture the change in utility from consuming natural gas.

The main constraints are applied to all cases while scenario constraints are case specific. The demand shocks are modeled by changing the baseline level of natural gas demand ($Demand_0(d)$).

B. N_{ew}ERA Model

1. Overview of the N_{ew}ERA Macroeconomic Model

The N_{ew}ERA macro model is a forward-looking, dynamic, computable general equilibrium model of the United States. The model simulates all economic interactions in the U.S. economy, including those among industry, households, and the government. The economic interactions are based on the IMPLAN[53] 2008 database for a benchmark year, which includes regional detail on economic interactions among 440 different economic sectors. The macroeconomic and energy forecasts that are used to project the benchmark year going forward are calibrated to the most recent AEO produced by the Energy Information Administration (EIA). Because the model is calibrated to an internally-consistent energy forecast, the use of the model is particularly well-suited to analyze economic and energy policies and environmental regulations.

2. Model Data (IMPLAN and EIA)

The economic data is taken from the IMPLAN 2008 database which includes balanced Social Accounting Matrices for all states in 2008. These inter-industry matrices provide a snapshot of the economy. Since the IMPLAN database contains only economic values, we benchmark energy supply, demand, trade, and prices to EIA historical statistics to capture the physical energy flows. The integration of the EIA energy quantities and prices into the IMPLAN economic database results in a balanced energy-economy dataset.

Future economic growth is calibrated to macroeconomic (GDP), energy supply, energy demand, and energy price forecasts from the EIA's AEO 2011. Labor productivity, labor growth, and population forecasts from the Census Bureau are used to project labor endowments along the baseline and ultimately employment by industry.

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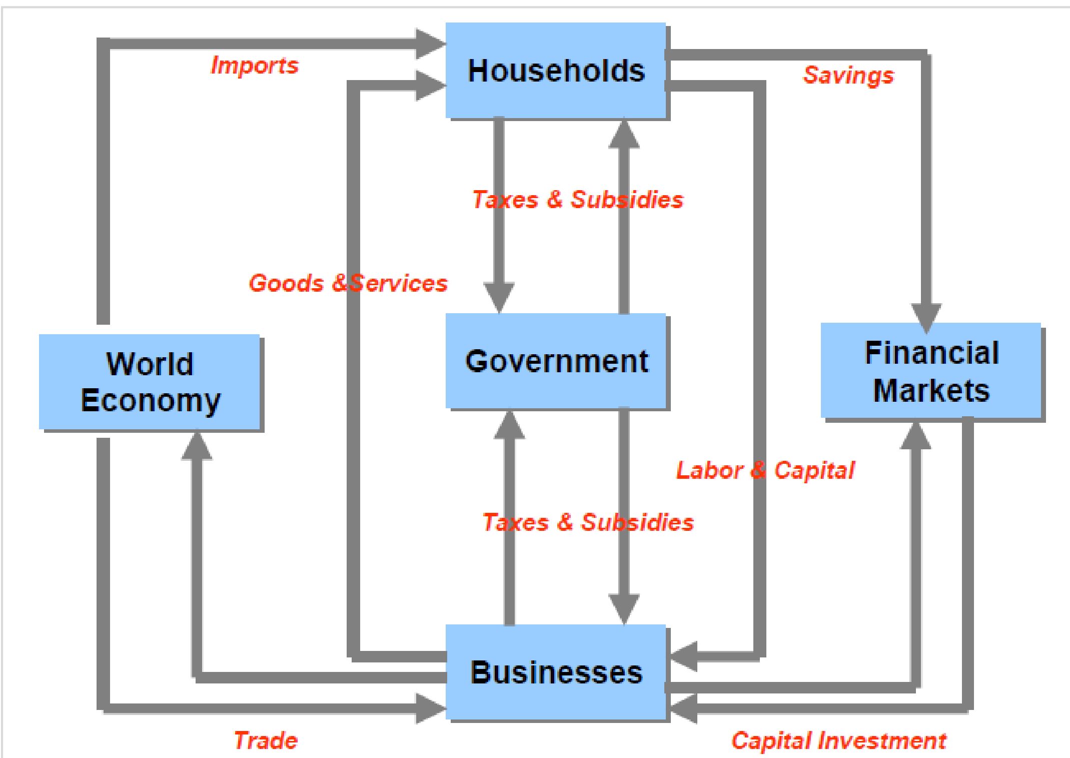
53 IMPLAN produces unique set of national structural matrices. The structural matrices form the bais for the inter-industry flows which we use to characterize the production, household, and government transactions, see www.implan.com.

3. Brief Discussion of Model Structure

The theoretical construct behind the N$_{ew}$ERA model is based on the circular flow of goods, services, and payments in the economy (every economic transaction has a buyer and a seller whereby goods/service go from a seller to a buyer and payment goes from the seller to the buyer). As shown in Figure 72, the model includes households, businesses, government, financial markets, and the rest of the world economy as they interact economically in the global economy. Households provide labor and capital to businesses, taxes to the government, and savings to financial markets, while also consuming goods and services and receiving government subsidies. Businesses produce goods and services, pay taxes to the government and use labor and capital. Businesses are both consumers and producers of capital for investment in the rest of the economy. Within the circular flow, equilibrium is found whereby goods and services consumed is equal to those produced and investments are optimized for the long term. Thus, supply is equal to demand in all markets.

The model assumes a perfect foresight, zero profit condition in production of goods and services, no changes in monetary policy, and full employment within the U.S. economy.

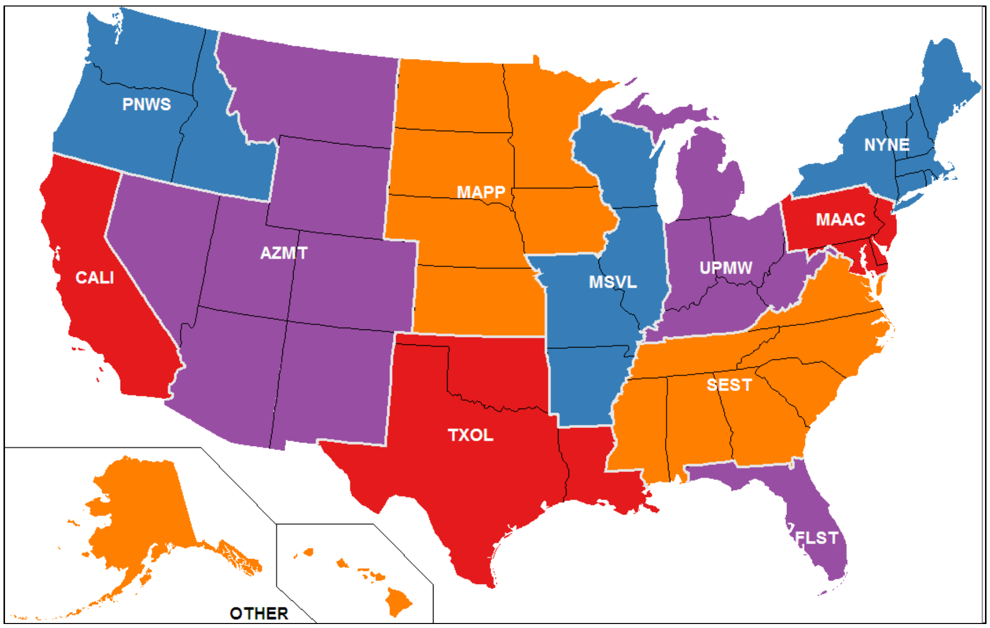
Figure 72: Circular Flow of Income



a. Regional Aggregation

The N_{ew}ERA macro model includes 11 regions: NYNE-New York and New England; MAAC-Mid-Atlantic Coast; UPMW-Upper Mid-West; SEST-South East; FLST-Florida; MSVL-Mississippi Valley; MAPP-Mid America; TXOL-Texas, Oklahoma, and Louisiana; AZMT-Arizona and Mountain states; CALI-California; and PNWS-Pacific Northwest.54 The aggregate model regions are built up from the 50 U.S. states' and the District of Columbia's economic data. The model is flexible enough to create other regional specifications, depending upon the need of the project. The 11 N_{ew}ERA regions and the States within each N_{ew}ERA region are shown in the following figure. For this Study we aggregate the 11 N_{ew}ERA regions into a single U.S. region.

Figure 73: N_{ew}ERA Macroeconomic Regions



b. Sectoral Aggregation

The N_{ew}ERA model includes 12 sectors: five energy (coal, natural gas, crude oil, electricity, and refined petroleum products) and seven non-energy sectors (services, manufacturing, energy-intensive, agriculture, commercial transportation excluding trucking, trucking, and motor vehicles). These sectors are aggregated up from the 440 IMPLAN sectors to 28 sectors, defined as the AEO sector in Figure 74. These 28 sectors' economic and energy data are consistent with IMPLAN and EIA, respectively. For this study, we further aggregate these 28 production sectors into 12 sectors. The mapping of the sectors is show below in Figure 72. The model has the flexibility to represent sectors at any level of aggregation.

[54] Hawaii and Alaska are included in the PNWS region.

Figure 74: N$_{ew}$ERA Sectoral Representation

	NewERA	AEO	
Final Demand	C	C	Household consumption
	G	G	Government consumption
	I	I	Investment demand
Energy Sectors	COL	COL	Coal
	GAS	GAS	Natural gas
	OIL	OIL	Refined Petroleum Products
	CRU	CRU	Crude oil
	ELE	ELE	Electricity
Non-Energy Sectors	AGR	AGR	Agriculture
	TRN	TRN	Transportation
	TRK	TRK	Trucking
	M_V	M_V	Motor vehicle
	SRV	SRV	Services
	SRV	DWE	Dwellings
	EIS	PAP	Paper and Pulp
	EIS	CHM	Chemicals
	EIS	GLS	Glass Industry
	EIS	CMT	Cement Industry
	EIS	I_S	Primary Metals
	EIS	ALU	Alumina and Aluminum
	MAN	CNS	Construction
	MAN	MIN	Mining
	MAN	FOO	Food, Beverage and Tobacco Products
	MAN	FAB	Fabricated Metal Products
	MAN	MAC	Machinery
	MAN	CMP	Computer and Electronic Products
	MAN	TRQ	Transportation Equipment
	MAN	ELQ	Electrical Equip., Appliances, and Components
	MAN	WOO	Wood and furniture
	MAN	PLA	Plastics
	MAN	OMA	Other Manufacturing sectors

c. Production and Consumption Characterization

Behavior of households, industries, investment, and government is characterized by nested constant elasticity of substitution production or utility functions. Under such a CES structure, inputs substitute against each other in a nested form. The ease of substitutability is determined by the value of the elasticity of substitution between the inputs. The higher the value of the substitution elasticity between the inputs, the greater the possibility of tradeoffs.

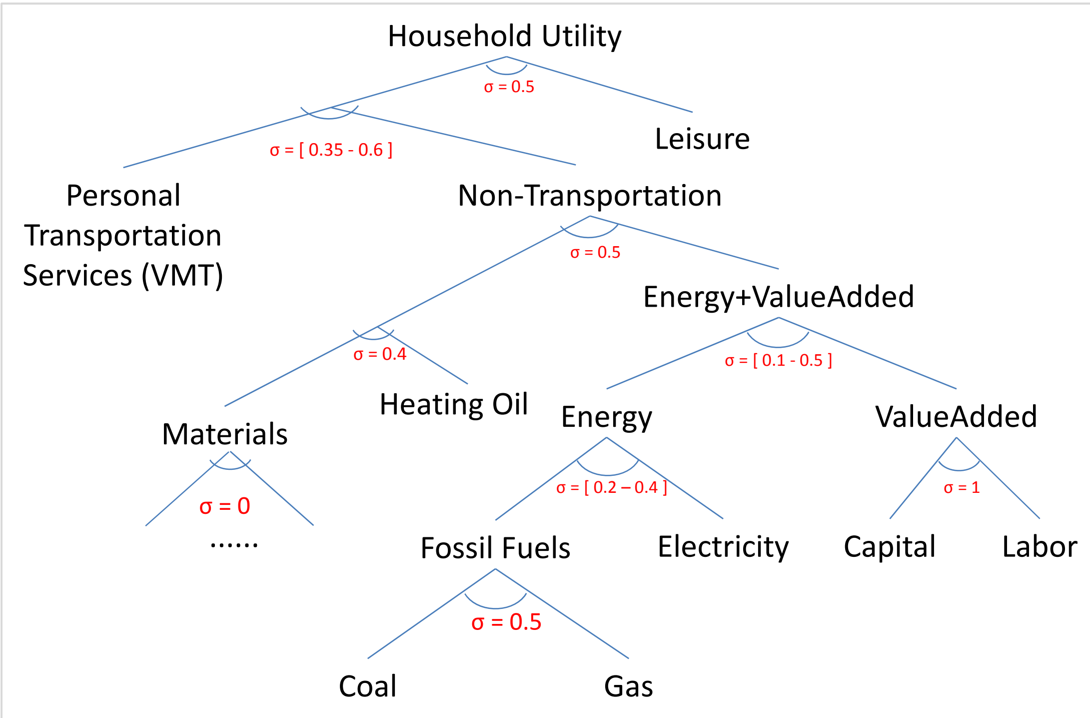
The CES nesting structure defines how inputs to a production activity compete with each other. In the generic production structure, intermediate inputs are aggregated in fixed proportion with a composite of energy and value-added inputs. The energy input aggregates fossil and non-fossil energy sources, and the value-added input combines capital and labor. Sectors with distinctive production characteristics are represented with structures different from the generic form. For alternative transportation fuels, such as ethanol and bio-diesel, inputs are demanded in fixed proportion. The characterization of nonrenewable resource supply adds a fixed resource that is calibrated to a declining resource base over time, so that it implies decreasing returns to scale.

This also implies rising marginal costs of production over time for exhaustible resources. The detailed nesting structure of the households and production sectors, with assumed elasticity of substitution parameters, are shown in figures below.

i. Households

Consumers are represented by a single representative household. The representative household derives utility from both consumption of goods and services, transportation services, and leisure. The utility is represented by a nested CES utility function. The elasticity of substitution parameters between goods are shown in Figure 75.

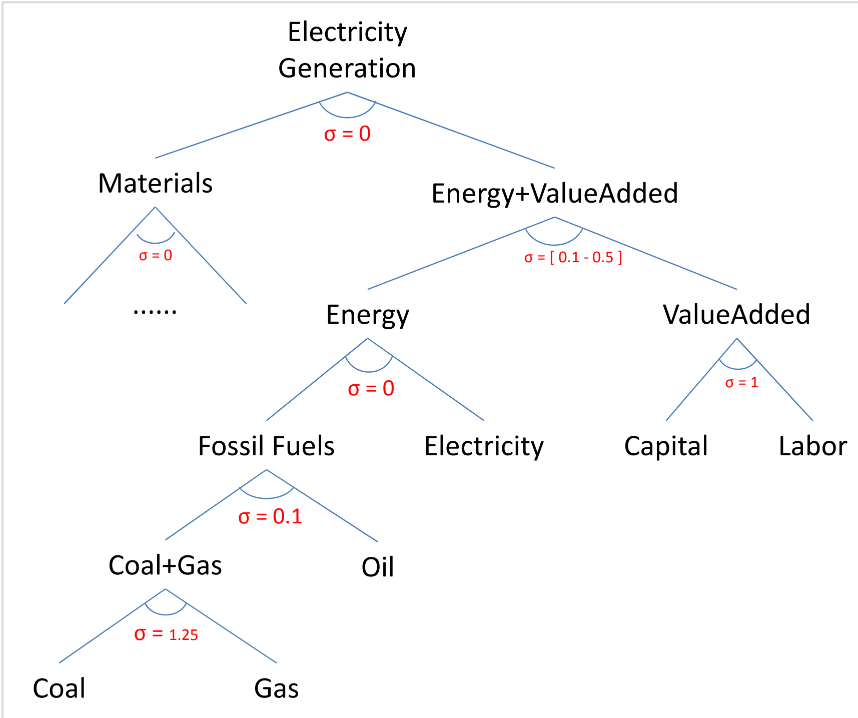
Figure 75: N$_{ew}$ERA Household Representation



ii. Electric Sector

We assume a simple representation of the electric sector. The electric sector models natural gas, coal, and oil-fired generation. The representation of the production is shown below.

Figure 76: N_{ew}ERA Electricity Sector Representation



iii. Other Sectors

The trucking and commercial transportation sector production structure is shown in Figure 77. The trucking sector uses diesel as transportation fuel. This sector has limited ability to substitute other fossil fuels. The other industrial sectors (agriculture, manufacturing, energy-intensive, motor vehicles) and the services sector production structure, with assumed elasticity of substitution, are shown in Figure 78.

Figure 77: N_{ew}ERA Trucking and Commercial Transportation Sector Representation

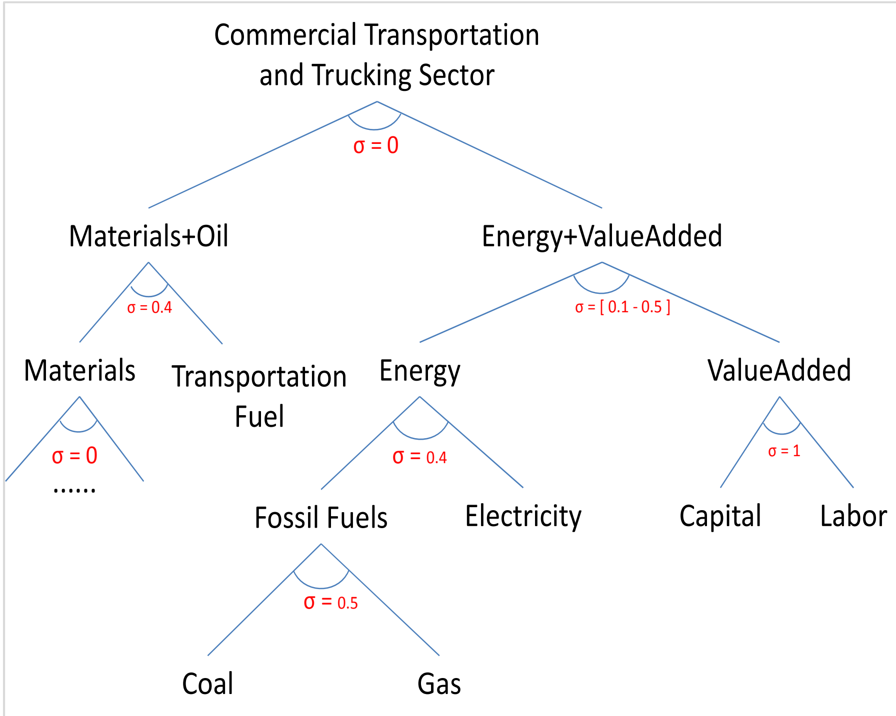
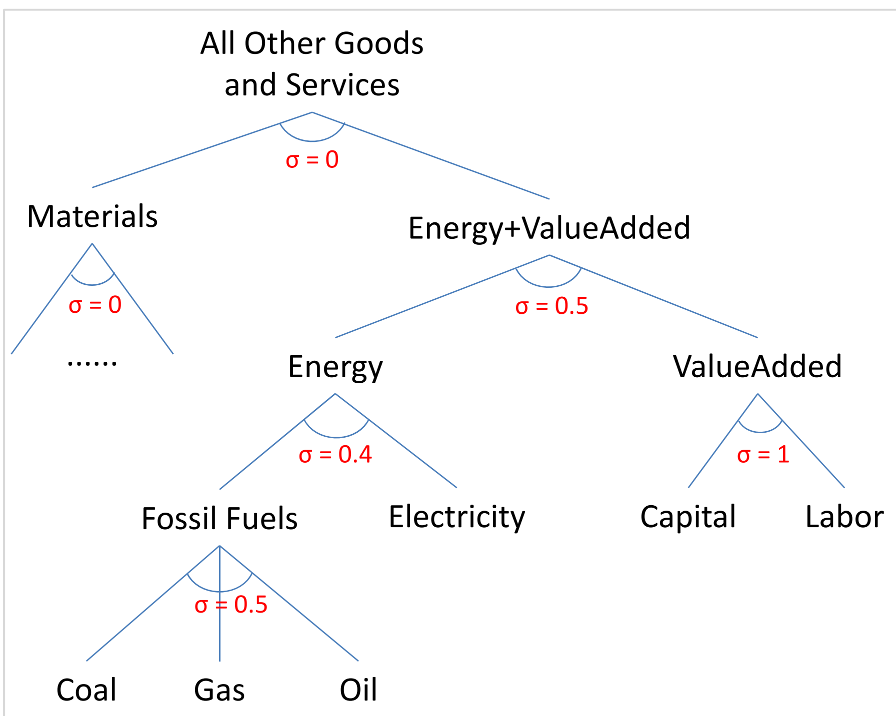


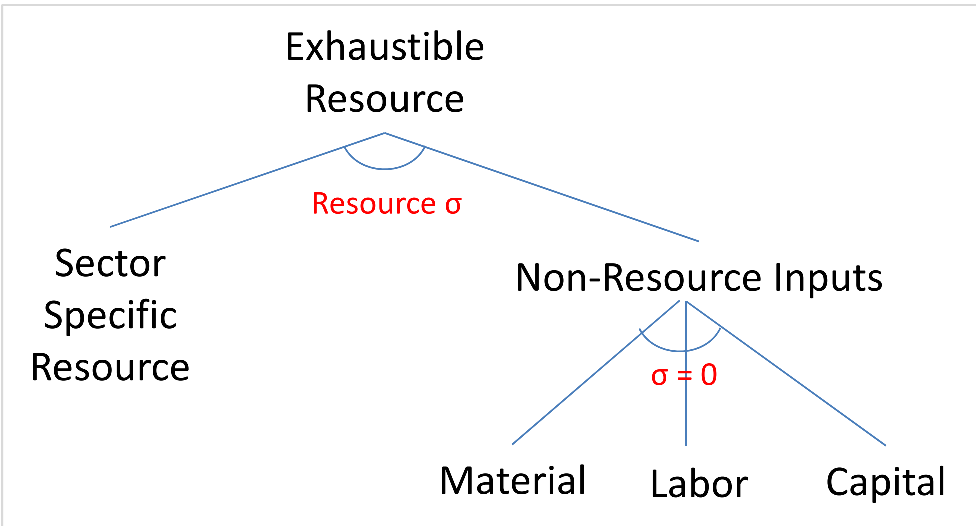
Figure 78: N_{ew}ERA Other Production Sector Representation



iv. Exhaustible Resource Sector

The simplest characterization of non-renewable resource supply adds a fixed resource that is calibrated to decline over time, so that the decreasing returns to scale implied for the non-resource inputs lead to rising marginal costs of production over time. The top level elasticity of substitution parameter is calibrated to be consistent with resource supply elasticity. We assume natural gas resource supply elasticity to be 0.25 in the short run (2010) and 1.5 in the long run (2050). Similarly, crude oil supply elasticity is assumed to be 0.3 in 2010 and 1.0 in 2050. Coal supply elasticity is assumed to be 0.4 in 2010 and 1.5 in 2050. The production structure of natural gas, crude oil, and coal is shown below.

Figure 79: N$_{ew}$ERA Resource Sector Representation



d. Trade Structure

All goods and services, except crude oil, are treated as Armington goods, which assumes that domestic and foreign goods are differentiated and thus, are imperfect substitutes. The level of imports depends upon the elasticity of substitution between the imported and domestic goods. The Armington elasticity among imported goods is assumed to be twice as large as the elasticity between domestic and aggregate imported goods, characterizing greater substitutability among imported goods.

We balance the international trade account in the N$_{ew}$ERA model by constraining changes in the current account deficit over the model horizon. The condition is that the net present value of the foreign indebtedness over the model horizon remains at the benchmark year level. This prevents distortions in economic effects that would result from perpetual increases in borrowing, but does not overly constrain the model by requiring current account balances in each year.

This treatment of the current account deficit does not mean that there cannot be trade benefits from LNG exports. Although trade will be in balance over time, the terms of trade shift in favor of the U.S. because of LNG exports. That is, by exporting goods of greater value to overseas customers, the U.S. is able to import larger quantities of goods than it would able to if the same domestic resources were devoted to producing exports of lesser value. Allowing high value exports to proceed has a similar effect on terms of trade as would an increase in the world price of existing exports or an increase in productivity in export industries. In all these cases, the U.S. gains more imported goods in exchange for the same amount of effort being devoted to production of goods for export. The opposite is also possible, in that a fall in the world price of U.S. exports or a subsidy that promoted exports of lesser value would move the terms of trade against the U.S., in that with the same effort put into producing exports the U.S. would receive less imports in exchange and terms of trade would move against the U.S. The fact that LNG will be exported only if there is sufficient market demand ensures that terms of trade will improve if LNG exports take place.

e. Investment Dynamics

Periods in the model are linked by capital and investment dynamics. Capital turnover in the model is represented by the standard process that capital at time t+1 equals capital at time t plus investment at time t minus depreciation. The model optimizes consumption and savings decisions in each period, taking account of changes in the economy over the entire model horizon with perfect foresight. The consumers forego consumption to save for current and future investment.

f. Model Assumptions

The underlying assumptions of labor growth and initial capital stock drive the economy over time in the model.

The model assumes full employment in the labor market. This assumption means total labor demand in a policy scenario would be the same as the baseline labor projection. The baseline labor projections are based on population growth and labor productivity forecasts over time. Hence, the labor projection can be thought to be a forecast of efficient labor units. The model assumes that labor is fungible across sectors. That is, labor can move freely out of a production sector into another sector without any adjustment costs or loss of productivity. Capital, on the other hand, is vintaged in the model. We assume two types of capital stock to portray the current technology and more advanced technologies that develop over time. A non-malleable capital (the clay) is used in fixed proportion in the existing production activity. The clay portion of the capital decays over time as new capital replaces it. A malleable capital (the putty) is used in new production activity. The putty capital in the new production activity can substitute against other inputs. The replacement of the clay capital depends upon the extent of use of new capital. This gradual capital turnover of the fixed capital stock and costs associated with it is represented by the putty-clay formulation.

Energy intensities are calibrated to the EIA projections. The differentiated energy intensities across regions result in different responses in energy supply and demand as energy price changes.

The $\mathrm{N_{ew}}$ERA macroeconomic model includes a simple tax representation. The model includes only two types of input taxes: marginal tax rates on capital and labor. The tax rates are based on the NBER TAXSIM model. Other indirect taxes such as excise and sales are included in the output values and not explicitly modeled.

The N_{ew}ERA macro model is solved through 2050, starting from 2010 in five-year time intervals.

g. Some Key Model Features

There are great uncertainties about how the U.S. natural gas market will evolve, and the N_{ew}ERA model is designed explicitly to address the key factors affecting future natural gas demand supply, and prices. One of the major uncertainties is the availability of shale gas in the United States. To account for this uncertainty and the subsequent effect it could have on the domestic markets, the N_{ew}ERA model includes resource supply curves for U.S. natural gas. The model also accounts for foreign imports, in particular pipeline imports from Canada, and the potential build-up of liquefaction plants for LNG exports. N_{ew}ERA also has a supply (demand) curve for U.S. imports (exports) that represents how the global LNG market price would react to changes in U.S. imports or exports. On a practical level, there are also other important uncertainties about the ownership of LNG plants and how the LNG contracts will be formulated. These have important consequences on how much revenue can be earned by the U.S. and hence overall macroeconomic impacts. In the N_{ew}ERA model it is possible to represent these variations in domestic versus foreign ownership of assets and capture of export revenues to better understand the issues.

In addition, we assume that natural gas is a homogenous good, similar to crude oil price. Hence, if there was a no-export constraint on LNG exports, domestic natural gas price will converge with the world net-back price.

Consumption of electricity as a transportation fuel could also affect the natural gas market. The N_{ew}ERA model is able to simulate impacts on the supply and disposition of transportation fuels (petroleum-based, biofuels, and electricity), along with responses to the personal driving behavior of the consumer. The personal driving or personal transportation services in the model is represented by Vehicle Miles Traveled ("VMT"), which takes vehicles' capital, transportation fuels, and other driving expenditures as inputs. The model chooses among changes in consumption of transportation fuels, changes in vehicle fuel efficiency, and changes in the overall level of travel in response to changes in the transportation fuel prices.

h. Advantages of the Macro Model Framework

The N_{ew}ERA model incorporates EIA energy quantities and energy prices into the IMPLAN Social Accounting Matrices. This in-house developed approach results in a balanced energy-economy dataset that has internally consistent energy benchmark data, as well as IMPLAN consistent economic values.

The macro model incorporates all production sectors and final demanders of the economy and is linked through terms of trade. The effects of policies are transmitted throughout the economy as all sectors and agents in the economy respond until the economy reaches equilibrium. The ability of the model to track these effects and substitution possibilities across sectors and regions makes it a unique tool for analyzing policies, such as those involving energy and environmental regulations. These general equilibrium substitution effects, however, are not fully captured in a partial equilibrium framework or within an input-output modeling framework. The smooth production and consumption functions employed in this general equilibrium model enable gradual substitution of inputs in response to relative price changes, thus, avoiding all or nothing solutions.

Business investment decisions are informed by future policies and outlook. The forward looking characteristic of the model enables businesses and consumers to determine the optimal savings and investment while anticipating future policies with perfect foresight. The alternative approach on savings and investment decisions is to assume agents in the model are myopic, thus, have no expectations for the future. Though both approaches are equally unrealistic to a certain extent, the latter approach can lead the model to produce inconsistent or incorrect impacts from an announced future policy.

The CGE modeling tool such as the N_{ew}ERA macro model can analyze scenarios or policies that call for large shocks outside historical observation. Econometric models are unsuitable for policies that impose large impacts because these models' production and consumption functions remain invariant under the policy. In addition, econometric models assume that the future path depends on the past experience and therefore fail to capture how the economy might respond under a different and new environment. For example, an econometric model cannot represent changes in fuel efficiency in response to increases in energy prices. However, the N_{ew}ERA macro model can consistently capture future policy changes that envisage having large effects.

The N_{ew}ERA macro model is also a unique tool that can iterate over sequential policies to generate consistent equilibrium solutions starting from an internally consistent equilibrium baseline forecast (such as the AEO reference case). This ability of the model is particularly helpful to decompose macroeconomic effects of individual policies. For example, if one desires to perform economic analysis of a policy that includes multiple regulations, the N_{ew}ERA modeling framework can be used as a tool to layer in one regulation at a time to determine the incremental effects of each policy.

i. Model Outputs

The N_{ew}ERA model outputs include supply and demand of all goods and services, prices of all commodities, and terms of trade effects (including changes in imports and exports). The model outputs also include gross regional product, consumption, investment, disposable income, and changes in income from labor, capital, and resources.

APPENDIX C – TABLES AND MODEL RESULTS

In this section, we present the numerical results from both the Global Natural Gas Model and the U.S. macroeconomic model ("N_{ew}ERA") for all the scenarios that were run as part of the study.

A. Global Natural Gas Model

We evaluated a total of 63 cases with all possible combinations of the following:

- Three domestic outlooks: Reference ("USREF"), High Shale EUR ("HEUR"), Low Shale EUR ("LEUR"),
- Three international outlooks: Reference ("INTREF"), Demand Shock ("D"), Supply/Demand Shock ("SD"), and
- Seven quota schedules: No-Export Capacity ("NX"), Low/Slowest ("LSS"), Low/Slow ('LS"), Low/Rapid ("LR"), High/Slow ("HS"), High/Rapid ("HR"), No-Export Constraint ("NC").

Out of the 45 cases where a quota is enforced, 21 are feasible (*i.e.,* projected U.S. LNG exports are at a level comparable to the quota allotted for each year), as shown in Figure 80. Detailed results for each case are shown in Figure 81 through Figure 143.

The U.S. Reference, International Reference, and the No-Export Capacity cases (Figure 81) are the ultimate baselines to which all other GNGM cases are compared. It assumes no U.S. and Canadian export capacities. After allowing for North American exports in the baseline scenario (Figure 87), our model determines that the U.S. does not export LNG, despite unlimited liquefaction capacities. Running the International Reference outlook with all three domestic outlooks, GNGM found that the U.S. is only able to export under the High Shale EUR scenario (Figure 87, Figure 108, and Figure 129). The projected level of exports is short of the high quotas specified by the EIA, even in the High Shale EUR case. We have thus developed two international shocks that favor U.S. LNG export.

The No-Export Constraint series shows the optimal amounts of U.S. exports under each domestic and international outlook as determined in GNGM. Since GNGM assumes a perfectly-competitive natural gas market, all quota rents are zero if the No-Export Constraint is in effect. A positive rent is collected, however, when the country supplies less than its perfectly-competitive volumes – Figure 105 is one example. When the number of export licenses available is greater than the optimal export level as determined by the natural gas market, the remaining licenses are unutilized and export rent drops to zero (Figure 93). The quota rent per MMBtu reaches the maximum under the High Shale EUR, Supply/Demand Shock, Low/Slowest quota scenario, where the conditions for U.S. exports are most favorable. However, the quota is highly restrictive (Figure 117). A high marginal price on an additional unit of export quota is thus generated.

Figure 80: Scenario Tree with Feasible Cases Highlighted

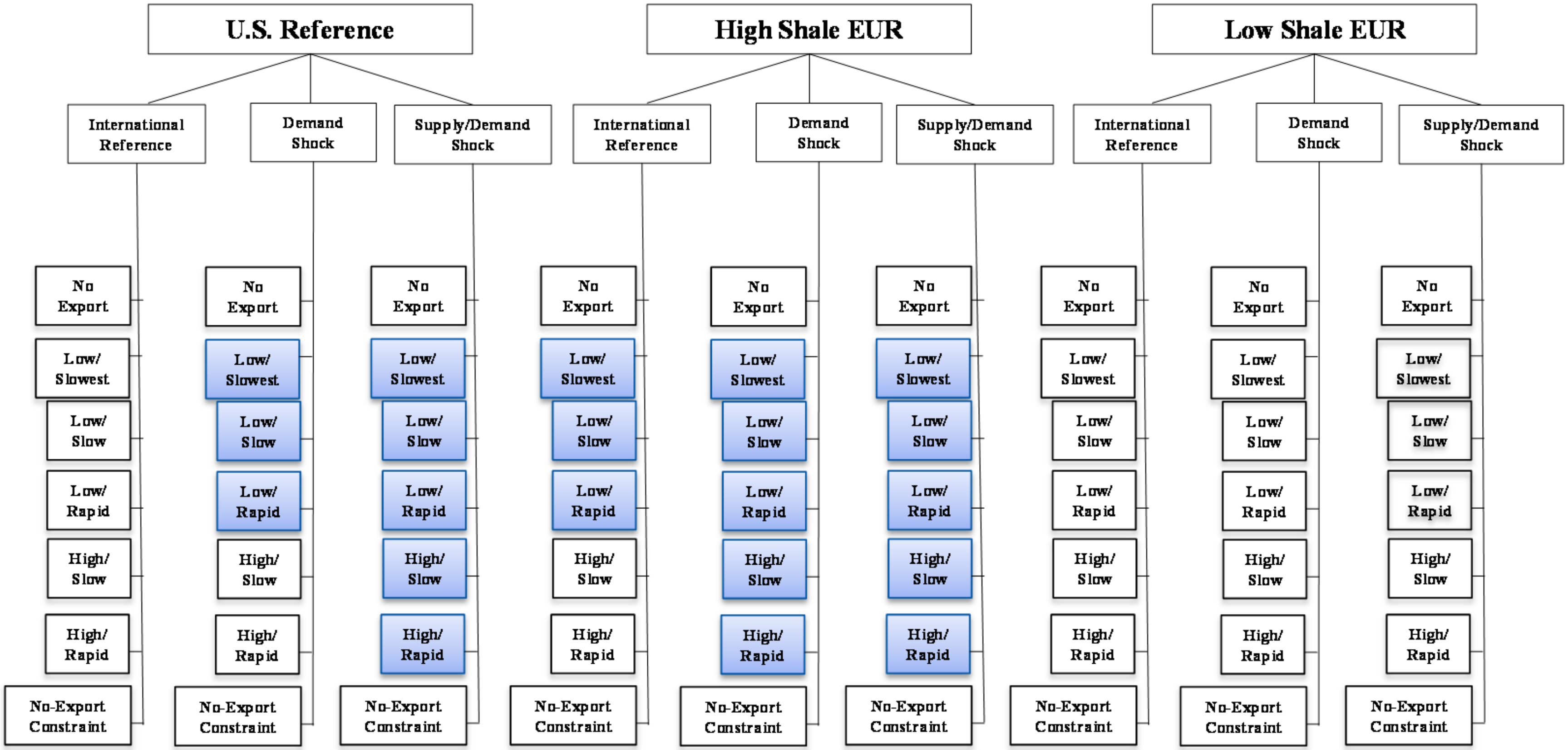


Figure 81: Detailed Results from Global Natural Gas Model, USREF_INTREF_NX

	EIA Ref	NERA Projections				
	2010	**2015**	**2020**	**2025**	**2030**	**2035**
Total Demand (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.09	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.10	22.39	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.23**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent (2010$/Mcf)	**-**	**$0.07**	**-**	**-**	**-**	**-**

Figure 82: Detailed Results from Global Natural Gas Model, USREF_INTREF_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$//Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$//Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 83: Detailed Results from Global Natural Gas Model, USREF_INTREF_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$//Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$//Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$//Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 84: Detailed Results from Global Natural Gas Model, USREF_INTREF_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$//Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 85: Detailed Results from Global Natural Gas Model, USREF_INTREF_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 86: Detailed Results from Global Natural Gas Model, USREF_INTREF_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 87: Detailed Results from Global Natural Gas Model, USREF_INTREF_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.10	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 88: Detailed Results from Global Natural Gas Model, USREF_D_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.09	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.39	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.23**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.85**	**$5.11**	**$6.23**	**$6.48**	**$7.18**
Quota Rent (2010$/Mcf)	**-**	**$0.62**	**$0.53**	**$0.81**	**$0.68**	**$0.77**

Figure 89: Detailed Results from Global Natural Gas Model, USREF_D_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.16**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.98	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.18	0.96	1.30	1.19	1.37
China/India	-	0.06	0.26	0.40	0.38	0.41
Europe	-	0.07	0.25	0.47	0.39	0.50
Korea/Japan	-	0.06	0.45	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.16**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.1	22.46	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.29**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.75**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**$0.46**	**-**	**-**	**-**	**-**

Figure 90: Detailed Results from Global Natural Gas Model, USREF_D_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.24**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.87	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.37	0.96	1.30	1.19	1.37
China/India	-	0.11	0.26	0.40	0.38	0.41
Europe	-	0.15	0.24	0.47	0.39	0.50
Korea/Japan	-	0.11	0.46	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.24**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.1	22.54	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.35**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.71**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**$0.35**	**-**	**-**	**-**	**-**

Figure 91: Detailed Results from Global Natural Gas Model, USREF_D_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.50	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.02	0.96	1.30	1.19	1.37
China/India	-	0.22	0.26	0.40	0.38	0.41
Europe	-	0.55	0.24	0.47	0.39	0.50
Korea/Japan	-	0.25	0.46	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.1	22.82	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 92: Detailed Results from Global Natural Gas Model, USREF_D_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.24**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.87	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.37	0.96	1.30	1.19	1.37
China/India	-	0.11	0.26	0.40	0.38	0.41
Europe	-	0.15	0.24	0.47	0.39	0.50
Korea/Japan	-	0.11	0.46	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.24**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.1	22.54	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.35**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.71**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**$0.35**	**-**	**-**	**-**	**-**

Figure 93: Detailed Results from Global Natural Gas Model, USREF_D_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.50	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.02	0.96	1.30	1.19	1.37
China/India	-	0.22	0.26	0.40	0.38	0.41
Europe	-	0.55	0.25	0.47	0.39	0.50
Korea/Japan	-	0.25	0.45	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.10	22.82	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 94: Detailed Results from Global Natural Gas Model, USREF_D_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.50	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.02	0.96	1.30	1.19	1.37
China/India	-	0.22	0.26	0.40	0.38	0.41
Europe	-	0.55	0.24	0.47	0.39	0.50
Korea/Japan	-	0.25	0.46	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.10	22.82	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 95: Detailed Results from Global Natural Gas Model, USREF_SD_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.09	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.39	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.23**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$5.83**	**$9.20**	**$10.04**	**$8.63**	**$9.33**
Quota Rent (2010$/Mcf)	**-**	**$1.60**	**$4.62**	**$4.61**	**$2.83**	**$2.92**

Figure 96: Detailed Results from Global Natural Gas Model, USREF_SD_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.16**	**25.83**	**26.21**	**27.25**	**27.97**
Domestic Demand	23.86	24.98	24.73	24.20	25.06	25.78
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.18	1.10	2.01	2.19	2.19
China/India	-	0.06	0.24	0.51	0.55	0.46
Europe	-	0.06	0.24	0.48	0.14	0.37
Korea/Japan	-	0.06	0.62	1.02	1.50	1.36
Total Supply (Tcf)	**23.86**	**25.16**	**25.83**	**26.21**	**27.25**	**27.97**
Domestic Production	21.1	22.46	23.93	25.11	26.45	27.87
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.29**	**$4.91**	**$5.99**	**$6.30**	**$6.82**
Netback Price (2010$/Mcf)	**-**	**$5.65**	**$6.29**	**$7.22**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$1.36**	**$1.38**	**$1.23**	**$1.20**	**$1.62**

Figure 97: Detailed Results from Global Natural Gas Model, USREF_SD_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.24**	**26.38**	**26.32**	**27.25**	**27.97**
Domestic Demand	23.86	24.87	24.19	24.13	25.06	25.78
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.37	2.19	2.19	2.19	2.19
China/India	-	0.11	0.33	0.54	0.55	0.46
Europe	-	0.13	0.35	0.51	0.14	0.37
Korea/Japan	-	0.13	1.51	1.14	1.50	1.36
Total Supply (Tcf)	**23.86**	**25.24**	**26.38**	**26.32**	**27.25**	**27.97**
Domestic Production	21.1	22.54	24.48	25.22	26.45	27.87
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.35**	**$5.25**	**$6.04**	**$6.30**	**$6.82**
Netback Price (2010$/Mcf)	**-**	**$5.59**	**$5.77**	**$7.15**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$1.24**	**$0.52**	**$1.11**	**$1.20**	**$1.62**

Figure 98: Detailed Results from Global Natural Gas Model, USREF_SD_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.56**	**26.38**	**26.32**	**27.25**	**27.97**
Domestic Demand	23.86	24.46	24.19	24.13	25.06	25.78
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.10	2.19	2.19	2.19	2.19
China/India	-	0.26	0.33	0.54	0.55	0.46
Europe	-	0.43	0.35	0.51	0.14	0.37
Korea/Japan	-	0.40	1.51	1.14	1.50	1.36
Total Supply (Tcf)	**23.86**	**25.56**	**26.38**	**26.32**	**27.25**	**27.97**
Domestic Production	21.1	22.86	24.48	25.22	26.45	27.87
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.61**	**$5.25**	**$6.04**	**$6.30**	**$6.82**
Netback Price (2010$/Mcf)	**-**	**$5.35**	**$5.77**	**$7.15**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$0.74**	**$0.52**	**$1.11**	**$1.20**	**$1.62**

Figure 99: Detailed Results from Global Natural Gas Model, USREF_SD_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.24**	**26.38**	**27.32**	**28.65**	**29.50**
Domestic Demand	23.86	24.87	24.19	23.39	24.27	25.12
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.37	2.19	3.93	4.38	4.38
China/India	-	0.11	0.33	0.83	0.93	0.75
Europe	-	0.13	0.35	0.77	0.27	0.59
Korea/Japan	-	0.13	1.51	2.34	3.17	3.03
Total Supply (Tcf)	**23.86**	**25.24**	**26.38**	**27.32**	**28.65**	**29.50**
Domestic Production	21.1	22.54	24.48	26.22	27.85	29.40
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.35**	**$5.25**	**$6.57**	**$6.82**	**$7.24**
Netback Price (2010$/Mcf)	**-**	**$5.59**	**$5.77**	**$6.57**	**$6.91**	**$7.91**
Quota Rent (2010$/Mcf)	**-**	**$1.24**	**$0.52**	**-**	**$0.08**	**$0.67**

Figure 100: Detailed Results from Global Natural Gas Model, USREF_SD_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.56**	**26.75**	**27.32**	**28.65**	**29.50**
Domestic Demand	23.86	24.46	23.83	23.39	24.27	25.12
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.10	2.92	3.93	4.38	4.38
China/India	-	0.26	0.46	0.83	0.93	0.75
Europe	-	0.43	0.74	0.77	0.27	0.59
Korea/Japan	-	0.40	1.72	2.34	3.17	3.03
Total Supply (Tcf)	**23.86**	**25.56**	**26.75**	**27.32**	**28.65**	**29.50**
Domestic Production	21.10	22.86	24.85	26.22	27.85	29.40
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.61**	**$5.49**	**$6.57**	**$6.82**	**$7.24**
Netback Price (2010$/Mcf)	**-**	**$5.35**	**$5.49**	**$6.57**	**$6.91**	**$7.91**
Quota Rent (2010$/Mcf)	**-**	**$0.74**	**-**	**-**	**$0.08**	**$0.67**

Figure 101: Detailed Results from Global Natural Gas Model, USREF_SD_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**26.02**	**26.75**	**27.32**	**28.76**	**30.47**
Domestic Demand	23.86	23.85	23.83	23.39	24.21	24.73
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	2.17	2.92	3.93	4.54	5.75
China/India	-	0.39	0.39	0.83	0.97	1.04
Europe	-	0.99	0.41	0.77	0.29	0.74
Korea/Japan	-	0.80	2.12	2.34	3.28	3.97
Total Supply (Tcf)	**23.86**	**26.02**	**26.75**	**27.32**	**28.76**	**30.47**
Domestic Production	21.10	23.32	24.85	26.22	27.96	30.37
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$5.02**	**$5.49**	**$6.57**	**$6.86**	**$7.50**
Netback Price (2010$/Mcf)	**-**	**$5.02**	**$5.49**	**$6.57**	**$6.86**	**$7.50**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 102: Detailed Results from Global Natural Gas Model, HEUR_INTREF_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Demand	23.86	26.98	27.66	27.82	28.60	29.71
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Production	21.1	24.60	26.29	27.45	28.62	30.33
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.27**	**$3.43**	**$4.03**	**$4.47**	**$4.88**
Netback Price (2010$/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent (2010$/Mcf)	**-**	**$1.03**	**$1.02**	**$1.21**	**$0.91**	**$0.92**

Figure 103: Detailed Results from Global Natural Gas Model, HEUR_INTREF_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Demand	23.86	26.88	27.13	26.98	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.18	1.10	2.01	2.19	2.19
China/India	-	-	0.11	0.65	0.74	0.69
Europe	-	0.18	0.99	1.02	1.30	1.35
Korea/Japan	-	-	0.00	0.34	0.14	0.15
Total Supply (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Production	21.1	24.68	26.86	28.62	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.49	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.01	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.31**	**$3.66**	**$4.41**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.24**	**$4.23**	**$4.94**	**$5.00**	**$5.48**
Quota Rent (2010$/Mcf)	**-**	**$0.93**	**$0.57**	**$0.53**	**$0.18**	**$0.32**

Figure 104: Detailed Results from Global Natural Gas Model, HEUR_INTREF_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.78	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	2.19	2.19	2.19
China/India	-	-	0.38	0.70	0.74	0.69
Europe	-	0.37	1.71	1.12	1.30	1.35
Korea/Japan	-	-	0.10	0.37	0.14	0.15
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	24.77	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.41	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.09	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.21**	**$4.13**	**$4.92**	**$5.00**	**$5.48**
Quota Rent (2010$/Mcf)	**-**	**$0.85**	**$0.24**	**$0.48**	**$0.18**	**$0.32**

Figure 105: Detailed Results from Global Natural Gas Model, HEUR_INTREF_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.37	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	2.19	2.19	2.19	2.19
China/India	-	-	0.38	0.70	0.74	0.69
Europe	-	1.10	1.71	1.12	1.30	1.35
Korea/Japan	-	-	0.10	0.37	0.14	0.15
Total Supply (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.10	25.09	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.41	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.09	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.08**	**$4.13**	**$4.92**	**$5.00**	**$5.48**
Quota Rent (2010$/Mcf)	**-**	**$0.53**	**$0.24**	**$0.48**	**$0.18**	**$0.32**

Figure 106: Detailed Results from Global Natural Gas Model, HEUR_INTREF_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**30.04**	**30.56**	**32.75**
Domestic Demand	23.86	26.78	26.61	26.26	27.60	28.69
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	3.77	2.78	3.38
China/India	-	-	0.38	1.06	0.89	1.01
Europe	-	0.37	1.71	1.99	1.73	2.22
Korea/Japan	-	-	0.10	0.72	0.16	0.16
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**30.04**	**30.56**	**32.75**
Domestic Production	21.1	24.77	27.43	29.67	30.40	32.69
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.41	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.09	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.76**	**$4.91**	**$5.31**
Netback Price (2010$/Mcf)	**-**	**$4.21**	**$4.13**	**$4.76**	**$4.91**	**$5.31**
Quota Rent (2010$/Mcf)	**-**	**$0.85**	**$0.24**	**-**	**-**	**-**

Figure 107: Detailed Results from Global Natural Gas Model, HEUR_INTREF_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**29.21**	**30.04**	**30.56**	**32.75**
Domestic Demand	23.86	26.37	26.24	26.26	27.60	28.69
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	2.97	3.77	2.78	3.38
China/India	-	-	0.72	1.06	0.89	1.01
Europe	-	1.10	1.96	1.99	1.73	2.22
Korea/Japan	-	-	0.28	0.72	0.16	0.16
Total Supply (Tcf)	**23.86**	**27.47**	**29.21**	**30.04**	**30.56**	**32.75**
Domestic Production	21.1	25.09	27.84	29.67	30.40	32.69
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.35	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.15	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$4.07**	**$4.76**	**$4.91**	**$5.31**
Netback Price (2010$/Mcf)	**-**	**$4.08**	**$4.07**	**$4.76**	**$4.91**	**$5.31**
Quota Rent (2010$/Mcf)	**-**	**$0.53**	**-**	**-**	**-**	**-**

Figure 108: Detailed Results from Global Natural Gas Model, HEUR_INTREF_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.98**	**29.21**	**30.04**	**30.56**	**32.75**
Domestic Demand	23.86	25.76	26.24	26.26	27.60	28.69
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	2.23	2.97	3.77	2.78	3.38
China/India	-	0.08	0.71	1.06	0.89	1.01
Europe	-	2.14	1.99	1.99	1.73	2.22
Korea/Japan	-	0.00	0.27	0.72	0.16	0.16
Total Supply (Tcf)	**23.86**	**27.98**	**29.21**	**30.04**	**30.56**	**32.75**
Domestic Production	21.10	25.60	27.84	29.67	30.40	32.69
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.35	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.15	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.86**	**$4.07**	**$4.76**	**$4.91**	**$5.31**
Netback Price (2010$/Mcf)	**-**	**$3.86**	**$4.07**	**$4.76**	**$4.91**	**$5.31**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 109: Detailed Results from Global Natural Gas Model, HEUR_D_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Demand	23.86	26.98	27.66	27.82	28.60	29.71
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Production	21.1	24.60	26.29	27.45	28.62	30.33
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.00	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.27**	**$3.43**	**$4.03**	**$4.47**	**$4.88**
Netback Price (2010$/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent (2010$/Mcf)	**-**	**$1.58**	**$1.67**	**$2.20**	**$2.01**	**$2.30**

Figure 110: Detailed Results from Global Natural Gas Model, HEUR_D_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Demand	23.86	26.88	27.13	26.98	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.18	1.10	2.01	2.19	2.19
China/India	-	0.06	0.28	0.59	0.68	0.63
Europe	-	0.07	0.28	0.75	0.72	0.84
Korea/Japan	-	0.06	0.54	0.67	0.79	0.72
Total Supply (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Production	21.1	24.68	26.86	28.62	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.31**	**$3.66**	**$4.41**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.75**	**$4.80**	**$5.55**	**$5.61**	**$6.31**
Quota Rent (2010$/Mcf)	**-**	**$1.44**	**$1.15**	**$1.15**	**$0.80**	**$1.15**

Figure 111: Detailed Results from Global Natural Gas Model, HEUR_D_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.78	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	2.19	2.19	2.19
China/India	-	0.11	0.47	0.64	0.68	0.63
Europe	-	0.15	0.63	0.81	0.72	0.84
Korea/Japan	-	0.11	1.10	0.73	0.79	0.72
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	24.77	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.71**	**$4.60**	**$5.51**	**$5.61**	**$6.31**
Quota Rent (2010$/Mcf)	**-**	**$1.35**	**$0.71**	**$1.07**	**$0.80**	**$1.15**

Figure 112: Detailed Results from Global Natural Gas Model, HEUR_D_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.37	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	2.19	2.19	2.19	2.19
China/India	-	0.23	0.47	0.64	0.68	0.63
Europe	-	0.61	0.63	0.81	0.72	0.84
Korea/Japan	-	0.26	1.10	0.73	0.79	0.72
Total Supply (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	25.09	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.56**	**$4.60**	**$5.51**	**$5.61**	**$6.31**
Quota Rent (2010$/Mcf)	**-**	**$1.01**	**$0.71**	**$1.07**	**$0.80**	**$1.15**

Figure 113: Detailed Results from Global Natural Gas Model, HEUR_D_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**30.18**	**31.61**	**33.46**
Domestic Demand	23.86	26.78	26.61	26.16	27.05	28.40
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	4.02	4.38	4.38
China/India	-	0.11	0.47	1.08	1.28	1.18
Europe	-	0.15	0.63	1.54	1.61	1.67
Korea/Japan	-	0.11	1.10	1.41	1.49	1.52
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**30.18**	**31.61**	**33.46**
Domestic Production	21.1	24.77	27.43	29.81	31.45	33.40
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.01	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.35	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.81**	**$5.18**	**$5.44**
Netback Price (2010$/Mcf)	**-**	**$4.71**	**$4.60**	**$5.08**	**$5.24**	**$5.77**
Quota Rent (2010$/Mcf)	**-**	**$1.35**	**$0.71**	**$0.27**	**$0.07**	**$0.33**

Figure 114: Detailed Results from Global Natural Gas Model, HEUR_D_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**29.73**	**30.40**	**31.61**	**33.46**
Domestic Demand	23.86	26.37	25.79	26.02	27.05	28.40
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	3.94	4.38	4.38	4.38
China/India	-	0.23	0.71	1.13	1.28	1.18
Europe	-	0.61	1.57	1.69	1.61	1.67
Korea/Japan	-	0.26	1.66	1.56	1.49	1.52
Total Supply (Tcf)	**23.86**	**27.47**	**29.73**	**30.40**	**31.61**	**33.46**
Domestic Production	21.1	25.09	28.36	30.03	31.45	33.40
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.00	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$4.30**	**$4.89**	**$5.18**	**$5.44**
Netback Price (2010$/Mcf)	**-**	**$4.56**	**$4.30**	**$5.04**	**$5.24**	**$5.77**
Quota Rent (2010$/Mcf)	**-**	**$1.01**	**-**	**$0.15**	**$0.07**	**$0.33**

Figure 115: Detailed Results from Global Natural Gas Model, HEUR_D_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**28.47**	**29.73**	**30.69**	**31.75**	**34.35**
Domestic Demand	23.86	25.18	25.79	25.83	26.98	28.06
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	3.30	3.94	4.87	4.59	5.61
China/India	-	0.43	0.70	1.20	1.33	1.52
Europe	-	2.30	1.79	1.88	1.71	2.19
Korea/Japan	-	0.58	1.45	1.79	1.55	1.90
Total Supply (Tcf)	**23.86**	**28.47**	**29.73**	**30.69**	**31.75**	**34.35**
Domestic Production	21.10	26.09	28.36	30.32	31.59	34.29
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.50	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.18**	**$4.30**	**$4.99**	**$5.21**	**$5.60**
Netback Price (2010$/Mcf)	**-**	**$4.18**	**$4.30**	**$4.99**	**$5.21**	**$5.60**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 116: Detailed Results from Global Natural Gas Model, HEUR_SD_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Demand	23.86	26.98	27.66	27.82	28.60	29.71
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Production	21.1	24.60	26.29	27.45	28.62	30.33
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.27**	**$3.43**	**$4.03**	**$4.47**	**$4.88**
Netback Price (2010$/Mcf)	**-**	**$5.83**	**$9.20**	**$10.04**	**$8.63**	**$9.33**
Quota Rent (2010$/Mcf)	**-**	**$2.56**	**$5.77**	**$6.01**	**$4.16**	**$4.45**

Figure 117: Detailed Results from Global Natural Gas Model, HEUR_SD_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Demand	23.86	26.88	27.13	26.98	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.18	1.10	2.01	2.19	2.19
China/India	-	0.06	0.23	0.51	0.55	0.46
Europe	-	0.06	0.24	0.48	0.14	0.37
Korea/Japan	-	0.06	0.63	1.02	1.50	1.36
Total Supply (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Production	21.10	24.68	26.86	28.62	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.31**	**$3.66**	**$4.41**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$5.65**	**$6.29**	**$7.22**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$2.34**	**$2.63**	**$2.81**	**$2.69**	**$3.28**

Figure 118: Detailed Results from Global Natural Gas Model, HEUR_SD_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.78	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	2.19	2.19	2.19
China/India	-	0.11	0.33	0.54	0.55	0.46
Europe	-	0.13	0.35	0.51	0.14	0.37
Korea/Japan	-	0.13	1.51	1.14	1.50	1.36
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	24.77	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$5.59**	**$5.77**	**$7.15**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$2.23**	**$1.88**	**$2.71**	**$2.69**	**$3.28**

Figure 119: Detailed Results from Global Natural Gas Model, HEUR_SD_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.37	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	2.19	2.19	2.19	2.19
China/India	-	0.26	0.33	0.54	0.55	0.46
Europe	-	0.43	0.35	0.51	0.14	0.37
Korea/Japan	-	0.40	1.51	1.14	1.50	1.36
Total Supply (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	25.09	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$5.35**	**$5.77**	**$7.15**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$1.80**	**$1.88**	**$2.71**	**$2.69**	**$3.28**

Figure 120: Detailed Results from Global Natural Gas Model, HEUR_SD_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**30.18**	**31.61**	**33.46**
Domestic Demand	23.86	26.78	26.61	26.16	27.05	28.40
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	4.02	4.38	4.38
China/India	-	0.11	0.33	0.84	0.93	0.75
Europe	-	0.13	0.35	0.78	0.27	0.59
Korea/Japan	-	0.13	1.51	2.39	3.17	3.03
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**30.18**	**31.61**	**33.46**
Domestic Production	21.1	24.77	27.43	29.81	31.45	33.40
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.81**	**$5.18**	**$5.44**
Netback Price (2010$/Mcf)	**-**	**$5.59**	**$5.77**	**$6.54**	**$6.91**	**$7.91**
Quota Rent (2010$/Mcf)	**-**	**$2.23**	**$1.88**	**$1.73**	**$1.73**	**$2.47**

Figure 121: Detailed Results from Global Natural Gas Model, HEUR_SD_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**29.97**	**30.40**	**31.61**	**33.46**
Domestic Demand	23.86	26.37	25.59	26.02	27.05	28.40
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	4.38	4.38	4.38	4.38
China/India	-	0.26	0.55	0.91	0.93	0.75
Europe	-	0.43	0.65	0.83	0.27	0.59
Korea/Japan	-	0.40	3.18	2.63	3.17	3.03
Total Supply (Tcf)	**23.86**	**27.47**	**29.97**	**30.40**	**31.61**	**33.46**
Domestic Production	21.1	25.09	28.60	30.03	31.45	33.40
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$4.41**	**$4.89**	**$5.18**	**$5.44**
Netback Price (2010$/Mcf)	**-**	**$5.35**	**$4.93**	**$6.41**	**$6.91**	**$7.91**
Quota Rent (2010$/Mcf)	**-**	**$1.80**	**$0.52**	**$1.53**	**$1.73**	**$2.47**

Figure 122: Detailed Results from Global Natural Gas Model, HEUR_SD_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**28.91**	**30.54**	**31.84**	**33.29**	**36.38**
Domestic Demand	23.86	24.68	25.10	25.11	26.22	27.31
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	4.23	5.44	6.72	6.89	8.39
China/India	-	0.51	0.69	1.60	1.75	2.00
Europe	-	2.23	1.04	1.09	0.57	1.18
Korea/Japan	-	1.49	3.71	4.03	4.57	5.21
Total Supply (Tcf)	**23.86**	**28.91**	**30.54**	**31.84**	**33.29**	**36.38**
Domestic Production	21.10	26.53	29.17	31.47	33.13	36.32
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.00	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.47**	**$4.68**	**$5.40**	**$5.61**	**$5.97**
Netback Price (2010$/Mcf)	**-**	**$4.47**	**$4.68**	**$5.40**	**$5.61**	**$5.97**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 123: Detailed Results from Global Natural Gas Model, LEUR_INTREF_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 124: Detailed Results from Global Natural Gas Model, LEUR_INTREF_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 125: Detailed Results from Global Natural Gas Model, LEUR_INTREF_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 126: Detailed Results from Global Natural Gas Model, LEUR_INTREF_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 127: Detailed Results from Global Natural Gas Model, LEUR_INTREF_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 128: Detailed Results from Global Natural Gas Model, LEUR_INTREF_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 129: Detailed Results from Global Natural Gas Model, LEUR_INTREF_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 130: Detailed Results from Global Natural Gas Model, LEUR_D_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 131: Detailed Results from Global Natural Gas Model, LEUR_D_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 132: Detailed Results from Global Natural Gas Model, LEUR_D_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 133: Detailed Results from Global Natural Gas Model, LEUR_D_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 134: Detailed Results from Global Natural Gas Model, LEUR_D_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 135: Detailed Results from Global Natural Gas Model, LEUR_D_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 136: Detailed Results from Global Natural Gas Model, LEUR_D_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 137: Detailed Results from Global Natural Gas Model, LEUR_SD_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$5.83**	**$9.20**	**$10.04**	**$8.63**	**$9.33**
Quota Rent ($2010/Mcf)	**-**	**-**	**$2.70**	**$2.47**	**$0.66**	**$0.63**

Figure 138: Detailed Results from Global Natural Gas Model, LEUR_SD_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 139: Detailed Results from Global Natural Gas Model, LEUR_SD_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 140: Detailed Results from Global Natural Gas Model, LEUR_SD_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 141: Detailed Results from Global Natural Gas Model, LEUR_SD_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 142: Detailed Results from Global Natural Gas Model, LEUR_SD_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 143: Detailed Results from Global Natural Gas Model, LEUR_SD_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

B. N_{ew}ERA Model Results

The following figures (Figure 144 through Figure 164) contain detailed macroeconomic outputs for all modeled baselines, scenarios, and sensitivities. For each figure, the "Level Values" section depicts the numerical results from the scenario or baseline, and the "Percentage Change" section shows the percentage change in the Level Values for a given scenario relative to its baseline case. Figure 144 through Figure 162 contain detailed results for the scenarios. Figure 163 through Figure 164 contain results for the sensitivity tests. All tables use the following acronyms defined in the following list:

AGR – agriculture sector
COL – coal sector
CRU – crude oil sector
EIS – energy-intensive sector
ELE – electricity sector
GAS – natural gas sector
M_V – motor vehicle manufacturing sector
MAN – other manufacturing sector
OIL – refining sector
SRV – commercial sector
TRK – commercial trucking sector
TRN – other commercial transportation sector
C – household sector
G – government sector

Figure 144: Detailed Results for U.S. Reference Baseline Case

Reference Baseline Case (USREF)								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,883	$17,862	$20,277	$22,880	$25,756
	Consumption		Billion 2010$	$12,404	$13,969	$15,972	$18,153	$20,521
	Investment		Billion 2010$	$2,467	$2,791	$3,161	$3,517	$3,977
Natural Gas	Wellhead Price		2010$ per Mcf	$4.29	$4.65	$5.49	$5.89	$6.50
	Production		Tcf	22.42	23.44	24.04	25.21	26.58
	Exports		Tcf	-	-	-	-	-
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	25.03	25.28	25.09	25.97	26.76
	Sectoral Demand	AGR	Tcf	0.16	0.16	0.16	0.16	0.17
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.33	3.35	3.27	3.16	3.08
		ELE	Tcf	6.94	6.82	6.65	7.35	7.93
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.18	0.18
		MAN	Tcf	4.23	4.32	4.34	4.41	4.54
		OIL	Tcf	1.32	1.41	1.36	1.40	1.38
		SRV	Tcf	2.44	2.53	2.58	2.67	2.79
		TRK	Tcf	0.47	0.48	0.49	0.53	0.56
		TRN	Tcf	0.22	0.22	0.23	0.24	0.26
		C	Tcf	4.80	4.84	4.84	4.84	4.82
		G	Tcf	0.93	0.96	0.99	1.02	1.06
	Export Revenues [1]		Billion 2010$	$0.00	$0.00	$0.00	$0.00	$0.00
Percentage Change								
Macro	Gross Domestic Product		%					
	Gross Capital Income		%					
	Gross Labor Income		%					
	Gross Resource Income		%					
	Consumption		%					
	Investment		%					
Natural Gas	Wellhead Price		%					
	Production		%					
	Pipeline Imports		%					
	Total Demand		%					
	Sectoral Demand	AGR	%					
		COL	%					
		CRU	%					
		EIS	%					
		ELE	%					
		GAS	%					
		M_V	%					
		MAN	%					
		OIL	%					
		SRV	%					
		TRK	%					
		TRN	%					
		C	%					
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 145: Detailed Results for High Shale EUR Baseline Case

High Shale EUR Baseline Case (HEUR)								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
			Level Values					
Macro	Gross Domestic Product		Billion 2010$	$15,960	$17,964	$20,411	$23,002	$25,902
	Consumption		Billion 2010$	$12,429	$13,999	$16,013	$18,184	$20,565
	Investment		Billion 2010$	$2,483	$2,811	$3,177	$3,532	$3,995
Natural Gas	Wellhead Price		2010$ per Mcf	$3.35	$3.50	$4.09	$4.53	$4.92
	Production		Tcf	24.69	26.46	27.72	28.70	29.73
	Exports		Tcf	-	-	-	-	-
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.96	27.73	27.97	28.84	29.86
	Sectoral Demand	AGR	Tcf	0.16	0.16	0.16	0.17	0.17
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.47	3.58	3.55	3.48	3.39
		ELE	Tcf	8.27	8.38	8.35	8.90	9.69
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.20	0.19	0.19	0.20
		MAN	Tcf	4.44	4.64	4.75	4.87	5.01
		OIL	Tcf	1.32	1.40	1.37	1.44	1.40
		SRV	Tcf	2.53	2.65	2.75	2.85	2.97
		TRK	Tcf	0.48	0.51	0.55	0.60	0.65
		TRN	Tcf	0.23	0.24	0.26	0.28	0.30
		C	Tcf	4.89	4.96	5.00	4.99	4.95
		G	Tcf	0.97	1.01	1.05	1.09	1.13
	Export Revenues 1		Billion 2010$	$0.00	$0.00	$0.00	$0.00	$0.00
			Percentage Change					
Macro	Gross Domestic Product		%					
	Gross Capital Income		%					
	Gross Labor Income		%					
	Gross Resource Income		%					
	Consumption		%					
	Investment		%					
Natural Gas	Wellhead Price		%					
	Production		%					
	Pipeline Imports		%					
	Total Demand		%					
	Sectoral Demand	AGR	%					
		COL	%					
		CRU	%					
		EIS	%					
		ELE	%					
		GAS	%					
		M_V	%					
		MAN	%					
		OIL	%					
		SRV	%					
		TRK	%					
		TRN	%					
		C	%					
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 146: Detailed Results for Low Shale EUR Baseline Case

Low Shale EUR Baseline Case (LEUR)								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,790	$17,716	$20,061	$22,693	$25,567
	Consumption		Billion 2010$	$12,379	$13,920	$15,862	$18,093	$20,476
	Investment		Billion 2010$	$2,442	$2,759	$3,138	$3,493	$3,953
Natural Gas	Wellhead Price		2010$ per Mcf	$5.73	$6.45	$7.83	$8.33	$8.96
	Production		Tcf	19.60	19.88	20.04	21.13	21.70
	Exports		Tcf	-	-	-	-	-
	Pipeline Imports		Tcf	3.00	2.61	2.37	2.01	1.75
	Total Demand		Tcf	22.60	22.50	22.41	23.14	23.45
	Sectoral Demand	AGR	Tcf	0.16	0.16	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.18	3.15	3.02	2.86	2.76
		ELE	Tcf	5.23	5.00	5.16	5.91	6.12
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.16	0.16
		MAN	Tcf	3.99	3.99	3.92	3.95	4.00
		OIL	Tcf	1.32	1.41	1.39	1.36	1.39
		SRV	Tcf	2.32	2.37	2.38	2.45	2.55
		TRK	Tcf	0.45	0.46	0.47	0.49	0.51
		TRN	Tcf	0.21	0.21	0.22	0.23	0.24
		C	Tcf	4.68	4.68	4.64	4.63	4.59
		G	Tcf	0.89	0.90	0.91	0.94	0.97
	Export Revenues 1		Billion 2010$	$0.00	$0.00	$0.00	$0.00	$0.00
Percentage Change								
Macro	Gross Domestic Product		%					
	Gross Capital Income		%					
	Gross Labor Income		%					
	Gross Resource Income		%					
	Consumption		%					
	Investment		%					
Natural Gas	Wellhead Price		%					
	Production		%					
	Pipeline Imports		%					
	Total Demand		%					
	Sectoral Demand	AGR	%					
		COL	%					
		CRU	%					
		EIS	%					
		ELE	%					
		GAS	%					
		M_V	%					
		MAN	%					
		OIL	%					
		SRV	%					
		TRK	%					
		TRN	%					
		C	%					
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 147: Detailed Results for USREF_D_LSS

Scenario: USREF_D_LSS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,884	$17,868	$20,281	$22,883	$25,759
	Consumption		Billion 2010$	$12,408	$13,971	$15,972	$18,152	$20,520
	Investment		Billion 2010$	$2,468	$2,790	$3,160	$3,518	$3,978
Natural Gas	Wellhead Price		2010$ per Mcf	$4.34	$4.92	$5.82	$6.13	$6.75
	Production		Tcf	22.49	23.84	24.80	25.87	27.40
	Exports		Tcf	0.18	0.98	1.43	1.19	1.37
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.92	24.71	24.41	25.44	26.20
	Sectoral Demand	AGR	Tcf	0.16	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.30	3.24	3.16	3.09	3.00
		ELE	Tcf	6.91	6.65	6.45	7.18	7.74
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.17	0.18
		MAN	Tcf	4.21	4.20	4.20	4.31	4.43
		OIL	Tcf	1.31	1.37	1.32	1.37	1.35
		SRV	Tcf	2.43	2.48	2.53	2.63	2.74
		TRK	Tcf	0.47	0.47	0.49	0.52	0.55
		TRN	Tcf	0.22	0.22	0.23	0.24	0.26
		C	Tcf	4.79	4.77	4.76	4.77	4.75
		G	Tcf	0.93	0.95	0.96	1.00	1.04
	Export Revenues [1]		Billion 2010$	$0.72	$4.47	$7.72	$6.76	$8.58
Percentage Change								
Macro	Gross Domestic Product		%	0.01	0.03	0.02	0.01	0.01
	Gross Capital Income		%	(0.01)	(0.07)	(0.08)	(0.06)	(0.05)
	Gross Labor Income		%	(0.01)	(0.05)	(0.07)	(0.05)	(0.04)
	Gross Resource Income		%	2.37	8.70	7.64	4.95	4.62
	Consumption		%	0.03	0.01	(0.00)	(0.00)	(0.00)
	Investment		%	0.05	(0.02)	(0.06)	0.03	0.04
Natural Gas	Wellhead Price		%	1.17	5.75	5.93	4.12	3.88
	Production		%	0.32	1.73	3.15	2.63	3.07
	Pipeline Imports		%					
	Total Demand		%	(0.43)	(2.28)	(2.68)	(2.03)	(2.07)
	Sectoral Demand	AGR	%	(0.66)	(3.11)	(3.44)	(2.51)	(2.46)
		COL	%					
		CRU	%					
		EIS	%	(0.65)	(3.07)	(3.41)	(2.50)	(2.45)
		ELE	%	(0.43)	(2.46)	(3.00)	(2.34)	(2.43)
		GAS	%					
		M_V	%	(0.42)	(2.23)	(2.70)	(2.06)	(2.10)
		MAN	%	(0.58)	(2.83)	(3.18)	(2.33)	(2.30)
		OIL	%	(0.59)	(2.89)	(3.21)	(2.34)	(2.30)
		SRV	%	(0.28)	(1.61)	(2.02)	(1.56)	(1.61)
		TRK	%	(0.17)	(1.03)	(1.45)	(1.16)	(1.26)
		TRN	%	(0.18)	(1.06)	(1.49)	(1.20)	(1.29)
		C	%	(0.23)	(1.38)	(1.76)	(1.36)	(1.42)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 148: Detailed Results for USREF_D_LS

Scenario: USREF_D_LS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,886	$17,867	$20,281	$22,883	$25,759
	Consumption		Billion 2010$	$12,408	$13,970	$15,972	$18,152	$20,520
	Investment		Billion 2010$	$2,467	$2,791	$3,160	$3,518	$3,978
Natural Gas	Wellhead Price		2010$ per Mcf	$4.40	$4.92	$5.82	$6.13	$6.75
	Production		Tcf	22.56	23.84	24.80	25.87	27.40
	Exports		Tcf	0.37	0.98	1.43	1.19	1.37
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.81	24.71	24.41	25.44	26.20
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.28	3.24	3.16	3.09	3.00
		ELE	Tcf	6.88	6.65	6.45	7.18	7.74
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.17	0.18
		MAN	Tcf	4.18	4.20	4.20	4.31	4.43
		OIL	Tcf	1.30	1.37	1.32	1.37	1.35
		SRV	Tcf	2.42	2.48	2.53	2.63	2.74
		TRK	Tcf	0.47	0.47	0.49	0.52	0.55
		TRN	Tcf	0.22	0.22	0.23	0.24	0.26
		C	Tcf	4.77	4.77	4.76	4.77	4.75
		G	Tcf	0.92	0.95	0.96	1.00	1.04
	Export Revenues [1]		Billion 2010$	$1.51	$4.47	$7.72	$6.76	$8.58
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.03	0.02	0.01	0.01
	Gross Capital Income		%	(0.03)	(0.07)	(0.08)	(0.06)	(0.05)
	Gross Labor Income		%	(0.02)	(0.05)	(0.07)	(0.05)	(0.04)
	Gross Resource Income		%	5.00	8.68	7.64	4.95	4.62
	Consumption		%	0.03	0.01	(0.00)	(0.00)	(0.00)
	Investment		%	0.01	(0.00)	(0.05)	0.03	0.04
Natural Gas	Wellhead Price		%	2.44	5.75	5.93	4.12	3.88
	Production		%	0.65	1.72	3.15	2.63	3.07
	Pipeline Imports		%					
	Total Demand		%	(0.90)	(2.28)	(2.69)	(2.03)	(2.07)
	Sectoral Demand	AGR	%	(1.34)	(3.12)	(3.44)	(2.51)	(2.46)
		COL	%					
		CRU	%					
		EIS	%	(1.31)	(3.07)	(3.41)	(2.50)	(2.45)
		ELE	%	(0.91)	(2.46)	(3.00)	(2.34)	(2.43)
		GAS	%					
		M_V	%	(0.85)	(2.23)	(2.70)	(2.06)	(2.10)
		MAN	%	(1.19)	(2.83)	(3.18)	(2.33)	(2.30)
		OIL	%	(1.21)	(2.89)	(3.21)	(2.34)	(2.30)
		SRV	%	(0.59)	(1.61)	(2.02)	(1.56)	(1.61)
		TRK	%	(0.35)	(1.03)	(1.45)	(1.17)	(1.26)
		TRN	%	(0.36)	(1.07)	(1.49)	(1.20)	(1.29)
		C	%	(0.50)	(1.38)	(1.76)	(1.36)	(1.42)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 149: Detailed Results for USREF_D_LR

Scenario: USREF_D_LR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,890	$17,866	$20,280	$22,882	$25,758
	Consumption		Billion 2010$	$12,408	$13,970	$15,972	$18,153	$20,521
	Investment		Billion 2010$	$2,464	$2,792	$3,160	$3,518	$3,978
Natural Gas	Wellhead Price		2010$ per Mcf	$4.60	$4.92	$5.82	$6.13	$6.75
	Production		Tcf	22.81	23.84	24.80	25.87	27.40
	Exports		Tcf	1.02	0.98	1.43	1.19	1.37
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.40	24.71	24.41	25.44	26.20
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.21	3.24	3.16	3.09	3.00
		ELE	Tcf	6.77	6.65	6.45	7.18	7.74
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.18	0.17	0.17	0.18
		MAN	Tcf	4.09	4.20	4.20	4.31	4.43
		OIL	Tcf	1.27	1.37	1.32	1.37	1.35
		SRV	Tcf	2.40	2.48	2.53	2.63	2.74
		TRK	Tcf	0.47	0.47	0.49	0.52	0.55
		TRN	Tcf	0.22	0.22	0.23	0.24	0.26
		C	Tcf	4.73	4.77	4.76	4.77	4.75
		G	Tcf	0.91	0.95	0.96	1.00	1.04
	Export Revenues [1]		Billion 2010$	$4.35	$4.47	$7.72	$6.76	$8.58
Percentage Change								
Macro	Gross Domestic Product		%	0.04	0.03	0.02	0.01	0.01
	Gross Capital Income		%	(0.09)	(0.08)	(0.09)	(0.06)	(0.05)
	Gross Labor Income		%	(0.07)	(0.06)	(0.07)	(0.05)	(0.04)
	Gross Resource Income		%	14.69	8.61	7.62	4.94	4.62
	Consumption		%	0.03	0.00	(0.00)	0.00	0.00
	Investment		%	(0.12)	0.04	(0.05)	0.03	0.04
Natural Gas	Wellhead Price		%	7.13	5.74	5.93	4.12	3.88
	Production		%	1.73	1.72	3.14	2.62	3.07
	Pipeline Imports		%					
	Total Demand		%	(2.52)	(2.28)	(2.69)	(2.03)	(2.07)
	Sectoral Demand	AGR	%	(3.72)	(3.13)	(3.45)	(2.52)	(2.46)
		COL	%					
		CRU	%					
		EIS	%	(3.62)	(3.09)	(3.42)	(2.51)	(2.46)
		ELE	%	(2.57)	(2.46)	(3.00)	(2.34)	(2.43)
		GAS	%					
		M_V	%	(2.37)	(2.24)	(2.70)	(2.07)	(2.10)
		MAN	%	(3.30)	(2.83)	(3.18)	(2.34)	(2.31)
		OIL	%	(3.42)	(2.89)	(3.21)	(2.34)	(2.30)
		SRV	%	(1.70)	(1.61)	(2.02)	(1.56)	(1.61)
		TRK	%	(0.99)	(1.04)	(1.45)	(1.17)	(1.26)
		TRN	%	(1.01)	(1.08)	(1.49)	(1.20)	(1.30)
		C	%	(1.46)	(1.38)	(1.76)	(1.35)	(1.42)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 150: Detailed Results for USREF_SD_LS

Scenario: USREF_SD_LS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,886	$17,876	$20,283	$22,885	$25,759
	Consumption		Billion 2010$	$12,411	$13,970	$15,971	$18,152	$20,520
	Investment		Billion 2010$	$2,469	$2,787	$3,161	$3,517	$3,977
Natural Gas	Wellhead Price		2010$ per Mcf	$4.40	$5.30	$6.01	$6.35	$6.92
	Production		Tcf	22.56	24.30	25.18	26.41	27.88
	Exports		Tcf	0.37	2.19	2.19	2.19	2.19
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.81	23.95	24.04	24.98	25.86
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.15	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.28	3.11	3.10	3.02	2.95
		ELE	Tcf	6.88	6.43	6.34	7.03	7.62
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.17	0.16	0.17	0.18
		MAN	Tcf	4.18	4.04	4.12	4.22	4.37
		OIL	Tcf	1.30	1.32	1.29	1.34	1.33
		SRV	Tcf	2.42	2.43	2.50	2.59	2.71
		TRK	Tcf	0.47	0.47	0.48	0.51	0.55
		TRN	Tcf	0.22	0.22	0.22	0.24	0.25
		C	Tcf	4.78	4.68	4.71	4.72	4.71
		G	Tcf	0.92	0.92	0.95	0.99	1.03
	Export Revenues [1]		Billion 2010$	$1.51	$10.76	$12.21	$12.90	$14.04
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.08	0.03	0.02	0.01
	Gross Capital Income		%	(0.02)	(0.17)	(0.14)	(0.11)	(0.09)
	Gross Labor Income		%	(0.02)	(0.13)	(0.11)	(0.09)	(0.08)
	Gross Resource Income		%	4.97	21.48	12.23	9.64	7.64
	Consumption		%	0.05	0.01	(0.01)	(0.01)	(0.00)
	Investment		%	0.09	(0.15)	(0.01)	0.01	0.01
Natural Gas	Wellhead Price		%	2.44	14.04	9.45	7.92	6.37
	Production		%	0.65	3.67	4.75	4.77	4.87
	Pipeline Imports		%					
	Total Demand		%	(0.90)	(5.26)	(4.18)	(3.80)	(3.35)
	Sectoral Demand	AGR	%	(1.37)	(7.14)	(5.35)	(4.68)	(3.97)
		COL	%					
		CRU	%					
		EIS	%	(1.35)	(7.03)	(5.31)	(4.65)	(3.96)
		ELE	%	(0.90)	(5.67)	(4.66)	(4.36)	(3.91)
		GAS	%					
		M_V	%	(0.88)	(5.15)	(4.19)	(3.86)	(3.40)
		MAN	%	(1.21)	(6.51)	(4.92)	(4.35)	(3.73)
		OIL	%	(1.21)	(6.64)	(4.98)	(4.36)	(3.71)
		SRV	%	(0.59)	(3.76)	(3.16)	(2.92)	(2.61)
		TRK	%	(0.35)	(2.42)	(2.27)	(2.19)	(2.05)
		TRN	%	(0.38)	(2.49)	(2.34)	(2.26)	(2.10)
		C	%	(0.47)	(3.24)	(2.76)	(2.55)	(2.30)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 151: Detailed Results for USREF_SD_LR

Scenario: USREF_SD_LR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,891	$17,874	$20,282	$22,885	$25,758
	Consumption		Billion 2010$	$12,411	$13,970	$15,971	$18,152	$20,521
	Investment		Billion 2010$	$2,465	$2,788	$3,161	$3,517	$3,977
Natural Gas	Wellhead Price		2010$ per Mcf	$4.62	$5.30	$6.01	$6.35	$6.92
	Production		Tcf	22.83	24.30	25.18	26.41	27.88
	Exports		Tcf	1.10	2.19	2.19	2.19	2.19
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.35	23.95	24.04	24.98	25.86
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.15	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.19	3.11	3.10	3.02	2.95
		ELE	Tcf	6.75	6.43	6.34	7.03	7.62
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.17	0.18
		MAN	Tcf	4.08	4.04	4.12	4.22	4.37
		OIL	Tcf	1.27	1.32	1.29	1.34	1.33
		SRV	Tcf	2.39	2.43	2.50	2.59	2.71
		TRK	Tcf	0.46	0.47	0.48	0.51	0.55
		TRN	Tcf	0.22	0.22	0.22	0.24	0.25
		C	Tcf	4.72	4.68	4.71	4.72	4.71
		G	Tcf	0.91	0.92	0.95	0.99	1.03
	Export Revenues [1]		Billion 2010$	$4.72	$10.76	$12.21	$12.90	$14.04
Percentage Change								
Macro	Gross Domestic Product		%	0.05	0.07	0.03	0.02	0.01
	Gross Capital Income		%	(0.09)	(0.18)	(0.14)	(0.12)	(0.09)
	Gross Labor Income		%	(0.08)	(0.14)	(0.11)	(0.09)	(0.08)
	Gross Resource Income		%	15.94	21.40	12.22	9.63	7.64
	Consumption		%	0.05	0.00	(0.01)	(0.00)	0.00
	Investment		%	(0.05)	(0.10)	(0.01)	0.01	0.01
Natural Gas	Wellhead Price		%	7.73	14.03	9.44	7.92	6.37
	Production		%	1.86	3.67	4.75	4.77	4.87
	Pipeline Imports		%					
	Total Demand		%	(2.73)	(5.26)	(4.18)	(3.80)	(3.35)
	Sectoral Demand	AGR	%	(4.04)	(7.15)	(5.36)	(4.68)	(3.98)
		COL	%					
		CRU	%					
		EIS	%	(3.94)	(7.05)	(5.32)	(4.66)	(3.97)
		ELE	%	(2.77)	(5.67)	(4.66)	(4.36)	(3.91)
		GAS	%					
		M_V	%	(2.58)	(5.15)	(4.20)	(3.86)	(3.40)
		MAN	%	(3.59)	(6.50)	(4.93)	(4.36)	(3.73)
		OIL	%	(3.69)	(6.64)	(4.98)	(4.36)	(3.71)
		SRV	%	(1.83)	(3.77)	(3.16)	(2.92)	(2.61)
		TRK	%	(1.07)	(2.43)	(2.27)	(2.20)	(2.05)
		TRN	%	(1.10)	(2.50)	(2.34)	(2.26)	(2.11)
		C	%	(1.55)	(3.25)	(2.76)	(2.55)	(2.29)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 152: Detailed Results for USREF_SD_HS

			Scenario: USREF_SD_HS					
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
			Level Values					
Macro	Gross Domestic Product		Billion 2010$	$15,886	$17,878	$20,294	$22,893	$25,763
	Consumption		Billion 2010$	$12,413	$13,976	$15,973	$18,150	$20,518
	Investment		Billion 2010$	$2,469	$2,792	$3,158	$3,515	$3,975
Natural Gas	Wellhead Price		2010$ per Mcf	$4.40	$5.30	$6.52	$6.92	$7.40
	Production		Tcf	22.56	24.30	26.03	27.55	29.13
	Exports		Tcf	0.37	2.19	3.93	4.38	4.38
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.80	23.95	23.15	23.93	24.93
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.15	0.15	0.15
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.28	3.11	2.95	2.86	2.83
		ELE	Tcf	6.88	6.44	6.08	6.69	7.30
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.17	0.16	0.16	0.17
		MAN	Tcf	4.18	4.04	3.94	4.01	4.19
		OIL	Tcf	1.30	1.32	1.24	1.28	1.28
		SRV	Tcf	2.42	2.43	2.43	2.51	2.64
		TRK	Tcf	0.47	0.47	0.47	0.50	0.53
		TRN	Tcf	0.22	0.22	0.22	0.23	0.25
		C	Tcf	4.78	4.68	4.59	4.58	4.59
		G	Tcf	0.92	0.92	0.92	0.95	1.00
	Export Revenues [1]		Billion 2010$	$1.51	$10.76	$23.75	$28.08	$30.03
			Percentage Change					
Macro	Gross Domestic Product		%	0.02	0.09	0.08	0.06	0.03
	Gross Capital Income		%	(0.02)	(0.16)	(0.24)	(0.24)	(0.20)
	Gross Labor Income		%	(0.02)	(0.12)	(0.19)	(0.19)	(0.16)
	Gross Resource Income		%	4.89	21.45	24.76	21.89	16.93
	Consumption		%	0.07	0.05	0.00	(0.02)	(0.01)
	Investment		%	0.11	0.03	(0.11)	(0.05)	(0.05)
Natural Gas	Wellhead Price		%	2.42	14.04	18.65	17.49	13.75
	Production		%	0.65	3.67	8.28	9.30	9.59
	Pipeline Imports		%					
	Total Demand		%	(0.90)	(5.26)	(7.73)	(7.84)	(6.84)
	Sectoral Demand	AGR	%	(1.41)	(7.17)	(9.83)	(9.58)	(8.08)
		COL	%					
		CRU	%					
		EIS	%	(1.39)	(7.08)	(9.73)	(9.52)	(8.05)
		ELE	%	(0.89)	(5.66)	(8.61)	(8.97)	(7.97)
		GAS	%					
		M_V	%	(0.89)	(5.17)	(7.76)	(7.94)	(6.95)
		MAN	%	(1.22)	(6.52)	(9.09)	(8.95)	(7.60)
		OIL	%	(1.21)	(6.64)	(9.17)	(8.97)	(7.56)
		SRV	%	(0.58)	(3.75)	(5.91)	(6.09)	(5.38)
		TRK	%	(0.36)	(2.42)	(4.26)	(4.61)	(4.25)
		TRN	%	(0.40)	(2.50)	(4.37)	(4.72)	(4.36)
		C	%	(0.45)	(3.21)	(5.18)	(5.36)	(4.76)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 153: Detailed Results for USREF_SD_HR

Scenario: USREF_SD_HR								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,891	$17,882	$20,292	$22,893	$25,762
	Consumption		Billion 2010$	$12,415	$13,974	$15,972	$18,151	$20,519
	Investment		Billion 2010$	$2,467	$2,789	$3,160	$3,516	$3,975
Natural Gas	Wellhead Price		2010$ per Mcf	$4.62	$5.57	$6.52	$6.91	$7.40
	Production		Tcf	22.83	24.55	26.03	27.55	29.13
	Exports		Tcf	1.10	2.92	3.93	4.38	4.38
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.35	23.48	23.15	23.93	24.93
	Sectoral Demand	AGR	Tcf	0.15	0.14	0.15	0.15	0.15
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.19	3.03	2.95	2.86	2.83
		ELE	Tcf	6.75	6.30	6.08	6.69	7.30
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.16	0.17
		MAN	Tcf	4.08	3.94	3.94	4.01	4.19
		OIL	Tcf	1.27	1.29	1.24	1.28	1.28
		SRV	Tcf	2.39	2.40	2.43	2.51	2.64
		TRK	Tcf	0.46	0.46	0.47	0.50	0.53
		TRN	Tcf	0.22	0.22	0.22	0.23	0.25
		C	Tcf	4.73	4.63	4.59	4.58	4.59
		G	Tcf	0.91	0.91	0.92	0.95	1.00
	Export Revenues [1]		Billion 2010$	$4.71	$15.07	$23.75	$28.08	$30.03
Percentage Change								
Macro	Gross Domestic Product		%	0.05	0.11	0.07	0.05	0.03
	Gross Capital Income		%	(0.09)	(0.24)	(0.25)	(0.24)	(0.20)
	Gross Labor Income		%	(0.07)	(0.19)	(0.20)	(0.19)	(0.16)
	Gross Resource Income		%	15.86	30.34	24.68	21.87	16.92
	Consumption		%	0.09	0.03	0.00	(0.01)	(0.01)
	Investment		%	0.01	(0.07)	(0.06)	(0.04)	(0.04)
Natural Gas	Wellhead Price		%	7.71	19.75	18.64	17.48	13.75
	Production		%	1.86	4.75	8.28	9.29	9.59
	Pipeline Imports		%					
	Total Demand		%	(2.73)	(7.15)	(7.73)	(7.84)	(6.84)
	Sectoral Demand	AGR	%	(4.09)	(9.69)	(9.85)	(9.59)	(8.09)
		COL	%					
		CRU	%					
		EIS	%	(3.99)	(9.55)	(9.76)	(9.53)	(8.06)
		ELE	%	(2.76)	(7.69)	(8.61)	(8.97)	(7.97)
		GAS	%					
		M_V	%	(2.60)	(7.00)	(7.76)	(7.95)	(6.95)
		MAN	%	(3.61)	(8.81)	(9.09)	(8.95)	(7.60)
		OIL	%	(3.69)	(8.99)	(9.18)	(8.97)	(7.56)
		SRV	%	(1.82)	(5.15)	(5.91)	(6.09)	(5.38)
		TRK	%	(1.08)	(3.34)	(4.27)	(4.61)	(4.26)
		TRN	%	(1.13)	(3.44)	(4.39)	(4.73)	(4.37)
		C	%	(1.52)	(4.43)	(5.18)	(5.35)	(4.76)

[1] Export revenues are based on LNG exports net of liquefaction loss.

Figure 154: Detailed Results for USREF_SD_NC

Scenario: USREF_SD_NC								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,900	$17,880	$20,292	$22,896	$25,773
	Consumption		Billion 2010$	$12,415	$13,973	$15,973	$18,153	$20,520
	Investment		Billion 2010$	$2,461	$2,791	$3,161	$3,520	$3,980
Natural Gas	Wellhead Price		2010$ per Mcf	$5.01	$5.57	$6.52	$6.96	$7.73
	Production		Tcf	23.19	24.55	26.03	27.63	29.90
	Exports		Tcf	2.17	2.92	3.93	4.54	5.75
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	23.64	23.47	23.15	23.85	24.33
	Sectoral Demand	AGR	Tcf	0.14	0.14	0.15	0.15	0.15
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.06	3.03	2.95	2.85	2.75
		ELE	Tcf	6.55	6.30	6.08	6.67	7.09
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.16	0.17
		MAN	Tcf	3.93	3.94	3.94	4.00	4.08
		OIL	Tcf	1.22	1.29	1.24	1.27	1.25
		SRV	Tcf	2.34	2.40	2.43	2.50	2.59
		TRK	Tcf	0.46	0.46	0.47	0.50	0.53
		TRN	Tcf	0.21	0.22	0.22	0.23	0.24
		C	Tcf	4.64	4.63	4.59	4.57	4.51
		G	Tcf	0.89	0.91	0.92	0.95	0.98
	Export Revenues [1]		Billion 2010$	$10.08	$15.06	$23.75	$29.29	$41.23
Percentage Change								
Macro	Gross Domestic Product		%	0.11	0.10	0.07	0.07	0.07
	Gross Capital Income		%	(0.20)	(0.25)	(0.25)	(0.24)	(0.24)
	Gross Labor Income		%	(0.17)	(0.19)	(0.20)	(0.19)	(0.20)
	Gross Resource Income		%	34.72	30.19	24.65	22.89	23.81
	Consumption		%	0.09	0.03	0.01	0.00	(0.00)
	Investment		%	(0.21)	0.02	(0.01)	0.10	0.09
Natural Gas	Wellhead Price		%	16.69	19.72	18.63	18.26	18.97
	Production		%	3.46	4.74	8.27	9.62	12.48
	Pipeline Imports		%					
	Total Demand		%	0.00	0.00	0.00	(0.00)	0.00
	Sectoral Demand	AGR	%	(5.57)	(7.15)	(7.74)	(8.14)	(9.09)
		COL	%	(8.17)	(9.71)	(9.86)	(9.96)	(10.69)
		CRU	%					
		EIS	%					
		ELE	%	(7.97)	(9.59)	(9.78)	(9.91)	(10.65)
		GAS	%	(5.64)	(7.69)	(8.61)	(9.31)	(10.56)
		M_V	%					
		MAN	%	(5.24)	(7.00)	(7.76)	(8.24)	(9.19)
		OIL	%	(7.25)	(8.81)	(9.09)	(9.29)	(10.06)
		SRV	%	(7.48)	(8.99)	(9.18)	(9.31)	(10.04)
		TRK	%	(3.78)	(5.15)	(5.91)	(6.33)	(7.19)
		TRN	%	(2.22)	(3.35)	(4.27)	(4.79)	(5.69)
		C	%	(2.28)	(3.47)	(4.40)	(4.92)	(5.83)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 155: Detailed Results for HEUR_D_NC

Scenario: HEUR_D_NC								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$16,000	$18,002	$20,442	$23,023	$25,929
	Consumption		Billion 2010$	$12,441	$14,000	$16,012	$18,184	$20,565
	Investment		Billion 2010$	$2,475	$2,812	$3,176	$3,537	$4,001
Natural Gas	Wellhead Price		2010$ per Mcf	$4.31	$4.46	$5.04	$5.25	$5.82
	Production		Tcf	25.66	27.83	30.04	31.24	32.82
	Exports		Tcf	3.30	3.94	4.87	4.59	5.61
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	24.63	25.16	25.42	26.79	27.35
	Sectoral Demand	AGR	Tcf	0.14	0.14	0.15	0.15	0.15
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.04	3.13	3.14	3.18	3.05
		ELE	Tcf	7.54	7.54	7.50	8.17	8.74
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.18	0.17	0.18	0.18
		MAN	Tcf	3.93	4.10	4.23	4.47	4.53
		OIL	Tcf	1.16	1.23	1.22	1.32	1.27
		SRV	Tcf	2.39	2.48	2.57	2.70	2.78
		TRK	Tcf	0.47	0.49	0.52	0.57	0.62
		TRN	Tcf	0.22	0.23	0.24	0.27	0.29
		C	Tcf	4.65	4.70	4.71	4.77	4.68
		G	Tcf	0.90	0.94	0.97	1.02	1.05
	Export Revenues [1]		Billion 2010$	$13.18	$16.30	$22.77	$22.33	$30.25
Percentage Change								
Macro	Gross Domestic Product		%	0.25	0.21	0.15	0.09	0.10
	Gross Capital Income		%	(0.31)	(0.32)	(0.29)	(0.20)	(0.21)
	Gross Labor Income		%	(0.24)	(0.23)	(0.22)	(0.15)	(0.16)
	Gross Resource Income		%	63.40	45.34	33.90	21.40	24.37
	Consumption		%	0.10	0.01	(0.01)	0.00	0.00
	Investment		%	(0.31)	0.06	(0.03)	0.14	0.15
Natural Gas	Wellhead Price		%	28.73	27.46	23.37	15.80	18.15
	Production		%	3.93	5.19	8.38	8.85	10.41
	Pipeline Imports		%					
	Total Demand		%	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
	Sectoral Demand	AGR	%	(8.64)	(9.26)	(9.10)	(7.11)	(8.42)
		COL	%	(12.74)	(12.66)	(11.72)	(8.79)	(10.02)
		CRU	%					
		EIS	%					
		ELE	%	(12.44)	(12.52)	(11.63)	(8.77)	(9.99)
		GAS	%	(8.80)	(9.99)	(10.17)	(8.15)	(9.86)
		M_V	%					
		MAN	%	(8.20)	(9.14)	(9.19)	(7.25)	(8.53)
		OIL	%	(11.47)	(11.61)	(10.89)	(8.22)	(9.45)
		SRV	%	(11.88)	(11.91)	(11.04)	(8.26)	(9.48)
		TRK	%	(5.65)	(6.35)	(6.61)	(5.27)	(6.32)
		TRN	%	(3.18)	(3.96)	(4.57)	(3.88)	(4.78)
		C	%	(3.24)	(4.10)	(4.70)	(4.00)	(4.91)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 156: Detailed Results for HEUR_SD_LSS

Scenario: HEUR_SD_LSS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,963	$17,974	$20,423	$23,011	$25,909
	Consumption		Billion 2010$	$12,433	$14,001	$16,013	$18,182	$20,563
	Investment		Billion 2010$	$2,484	$2,812	$3,176	$3,531	$3,995
Natural Gas	Wellhead Price		2010$ per Mcf	$3.39	$3.72	$4.43	$4.84	$5.23
	Production		Tcf	24.76	26.89	28.73	29.95	30.97
	Exports		Tcf	0.18	1.10	2.01	2.19	2.19
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.84	27.06	26.98	27.89	28.92
	Sectoral Demand	AGR	Tcf	0.16	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.45	3.46	3.39	3.34	3.26
		ELE	Tcf	8.23	8.16	8.02	8.56	9.33
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.19	0.18	0.18	0.19
		MAN	Tcf	4.41	4.49	4.55	4.68	4.83
		OIL	Tcf	1.31	1.36	1.31	1.38	1.35
		SRV	Tcf	2.53	2.61	2.68	2.78	2.90
		TRK	Tcf	0.48	0.51	0.54	0.59	0.64
		TRN	Tcf	0.22	0.24	0.25	0.27	0.30
		C	Tcf	4.88	4.90	4.89	4.89	4.85
		G	Tcf	0.96	0.99	1.02	1.06	1.10
	Export Revenues [1]		Billion 2010$	$0.57	$3.80	$8.25	$9.83	$10.62
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.06	0.06	0.04	0.03
	Gross Capital Income		%	(0.01)	(0.06)	(0.10)	(0.09)	(0.08)
	Gross Labor Income		%	(0.01)	(0.04)	(0.07)	(0.07)	(0.06)
	Gross Resource Income		%	2.58	10.21	11.75	9.10	8.13
	Consumption		%	0.03	0.02	(0.00)	(0.01)	(0.01)
	Investment		%	0.06	0.04	(0.02)	(0.01)	(0.01)
Natural Gas	Wellhead Price		%	1.20	6.29	8.29	6.87	6.27
	Production		%	0.26	1.64	3.66	4.33	4.18
	Pipeline Imports		%					
	Total Demand		%	(0.43)	(2.41)	(3.56)	(3.29)	(3.17)
	Sectoral Demand	AGR	%	(0.68)	(3.35)	(4.61)	(4.07)	(3.79)
		COL	%					
		CRU	%					
		EIS	%	(0.67)	(3.30)	(4.57)	(4.05)	(3.77)
		ELE	%	(0.43)	(2.61)	(4.00)	(3.78)	(3.73)
		GAS	%					
		M_V	%	(0.43)	(2.40)	(3.60)	(3.35)	(3.22)
		MAN	%	(0.60)	(3.07)	(4.29)	(3.81)	(3.57)
		OIL	%	(0.60)	(3.14)	(4.36)	(3.84)	(3.58)
		SRV	%	(0.26)	(1.59)	(2.53)	(2.41)	(2.34)
		TRK	%	(0.15)	(0.98)	(1.73)	(1.76)	(1.76)
		TRN	%	(0.17)	(1.01)	(1.77)	(1.80)	(1.80)
		C	%	(0.20)	(1.32)	(2.15)	(2.08)	(2.02)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 157: Detailed Results for HEUR_SD_LS

Scenario: HEUR_SD_LS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,965	$17,984	$20,422	$23,011	$25,909
	Consumption		Billion 2010$	$12,435	$14,000	$16,012	$18,182	$20,564
	Investment		Billion 2010$	$2,485	$2,808	$3,177	$3,532	$3,996
Natural Gas	Wellhead Price		2010$ per Mcf	$3.43	$3.98	$4.46	$4.84	$5.23
	Production		Tcf	24.82	27.28	28.82	29.95	30.97
	Exports		Tcf	0.37	2.19	2.19	2.19	2.19
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.72	26.36	26.88	27.89	28.92
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.42	3.34	3.38	3.34	3.26
		ELE	Tcf	8.20	7.93	7.99	8.56	9.33
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.19	0.18	0.18	0.19
		MAN	Tcf	4.38	4.35	4.53	4.68	4.83
		OIL	Tcf	1.30	1.31	1.30	1.38	1.35
		SRV	Tcf	2.52	2.56	2.67	2.78	2.90
		TRK	Tcf	0.48	0.50	0.54	0.59	0.64
		TRN	Tcf	0.22	0.23	0.25	0.27	0.30
		C	Tcf	4.87	4.82	4.88	4.89	4.85
		G	Tcf	0.96	0.97	1.02	1.06	1.10
	Export Revenues [1]		Billion 2010$	$1.18	$8.07	$9.06	$9.83	$10.62
Percentage Change								
Macro	Gross Domestic Product		%	0.03	0.11	0.06	0.04	0.03
	Gross Capital Income		%	(0.02)	(0.15)	(0.12)	(0.09)	(0.08)
	Gross Labor Income		%	(0.01)	(0.11)	(0.09)	(0.07)	(0.06)
	Gross Resource Income		%	5.44	22.13	12.88	9.08	8.12
	Consumption		%	0.05	0.00	(0.01)	(0.01)	(0.01)
	Investment		%	0.10	(0.10)	0.01	0.01	0.01
Natural Gas	Wellhead Price		%	2.52	13.51	9.11	6.86	6.27
	Production		%	0.53	3.11	3.97	4.33	4.18
	Pipeline Imports		%					
	Total Demand		%	(0.89)	(4.93)	(3.89)	(3.29)	(3.17)
	Sectoral Demand	AGR	%	(1.38)	(6.79)	(5.05)	(4.08)	(3.79)
		COL	%					
		CRU	%					
		EIS	%	(1.35)	(6.70)	(5.02)	(4.06)	(3.78)
		ELE	%	(0.90)	(5.34)	(4.37)	(3.79)	(3.73)
		GAS	%					
		M_V	%	(0.88)	(4.88)	(3.94)	(3.35)	(3.22)
		MAN	%	(1.23)	(6.25)	(4.69)	(3.82)	(3.57)
		OIL	%	(1.24)	(6.41)	(4.77)	(3.84)	(3.58)
		SRV	%	(0.55)	(3.31)	(2.77)	(2.41)	(2.34)
		TRK	%	(0.32)	(2.05)	(1.90)	(1.76)	(1.76)
		TRN	%	(0.33)	(2.09)	(1.96)	(1.81)	(1.81)
		C	%	(0.43)	(2.78)	(2.37)	(2.08)	(2.02)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 158: Detailed Results for HEUR_SD_LR

Scenario: HEUR_SD_LR								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,972	$17,983	$20,422	$23,010	$25,909
	Consumption		Billion 2010$	$12,435	$13,999	$16,012	$18,182	$20,564
	Investment		Billion 2010$	$2,482	$2,809	$3,178	$3,532	$3,996
Natural Gas	Wellhead Price		2010$ per Mcf	$3.61	$3.97	$4.46	$4.84	$5.23
	Production		Tcf	25.06	27.28	28.82	29.94	30.97
	Exports		Tcf	1.10	2.19	2.19	2.19	2.19
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.23	26.36	26.88	27.89	28.92
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.33	3.34	3.37	3.34	3.26
		ELE	Tcf	8.04	7.93	7.99	8.56	9.33
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.19	0.18	0.18	0.19
		MAN	Tcf	4.27	4.35	4.53	4.68	4.83
		OIL	Tcf	1.27	1.31	1.30	1.38	1.35
		SRV	Tcf	2.49	2.56	2.67	2.78	2.90
		TRK	Tcf	0.48	0.50	0.54	0.59	0.64
		TRN	Tcf	0.22	0.23	0.25	0.27	0.30
		C	Tcf	4.82	4.82	4.88	4.89	4.85
		G	Tcf	0.95	0.97	1.02	1.06	1.10
	Export Revenues [1]		Billion 2010$	$3.69	$8.07	$9.06	$9.83	$10.62
Percentage Change								
Macro	Gross Domestic Product		%	0.07	0.11	0.06	0.03	0.03
	Gross Capital Income		%	(0.09)	(0.16)	(0.12)	(0.09)	(0.08)
	Gross Labor Income		%	(0.07)	(0.11)	(0.09)	(0.07)	(0.06)
	Gross Resource Income		%	17.33	22.05	12.86	9.07	8.11
	Consumption		%	0.05	(0.00)	(0.01)	(0.01)	(0.00)
	Investment		%	(0.02)	(0.05)	0.02	0.01	0.01
Natural Gas	Wellhead Price		%	7.97	13.49	9.11	6.86	6.27
	Production		%	1.49	3.10	3.97	4.32	4.18
	Pipeline Imports		%					
	Total Demand		%	(2.71)	(4.94)	(3.90)	(3.29)	(3.17)
	Sectoral Demand	AGR	%	(4.08)	(6.80)	(5.06)	(4.08)	(3.80)
		COL	%					
		CRU	%					
		EIS	%	(3.98)	(6.71)	(5.03)	(4.07)	(3.79)
		ELE	%	(2.76)	(5.35)	(4.37)	(3.78)	(3.73)
		GAS	%					
		M_V	%	(2.60)	(4.88)	(3.94)	(3.36)	(3.22)
		MAN	%	(3.67)	(6.25)	(4.69)	(3.82)	(3.58)
		OIL	%	(3.78)	(6.41)	(4.76)	(3.84)	(3.58)
		SRV	%	(1.71)	(3.32)	(2.78)	(2.41)	(2.34)
		TRK	%	(0.96)	(2.05)	(1.90)	(1.76)	(1.76)
		TRN	%	(0.98)	(2.11)	(1.96)	(1.81)	(1.81)
		C	%	(1.42)	(2.78)	(2.36)	(2.07)	(2.02)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 159: Detailed Results for HEUR_SD_HS

Scenario: HEUR_SD_HS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,965	$17,986	$20,439	$23,022	$25,918
	Consumption		Billion 2010$	$12,437	$14,004	$16,013	$18,180	$20,561
	Investment		Billion 2010$	$2,486	$2,813	$3,175	$3,531	$3,994
Natural Gas	Wellhead Price		2010$ per Mcf	$3.43	$3.98	$4.84	$5.21	$5.59
	Production		Tcf	24.82	27.28	29.67	31.13	32.17
	Exports		Tcf	0.37	2.19	4.02	4.38	4.38
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.72	26.36	25.90	26.89	27.92
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.15	0.15	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.42	3.34	3.22	3.20	3.13
		ELE	Tcf	8.20	7.93	7.66	8.21	8.95
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.19	0.17	0.18	0.18
		MAN	Tcf	4.38	4.35	4.33	4.49	4.64
		OIL	Tcf	1.30	1.31	1.24	1.32	1.30
		SRV	Tcf	2.52	2.56	2.60	2.70	2.82
		TRK	Tcf	0.48	0.50	0.53	0.58	0.63
		TRN	Tcf	0.22	0.23	0.25	0.27	0.29
		C	Tcf	4.87	4.82	4.77	4.78	4.75
		G	Tcf	0.96	0.97	0.99	1.03	1.07
	Export Revenues [1]		Billion 2010$	$1.18	$8.07	$18.05	$21.15	$22.70
Percentage Change								
Macro	Gross Domestic Product		%	0.03	0.12	0.14	0.09	0.06
	Gross Capital Income		%	(0.02)	(0.14)	(0.21)	(0.19)	(0.17)
	Gross Labor Income		%	(0.01)	(0.10)	(0.16)	(0.14)	(0.13)
	Gross Resource Income		%	5.38	22.12	26.64	20.29	17.95
	Consumption		%	0.06	0.04	(0.01)	(0.02)	(0.02)
	Investment		%	0.12	0.08	(0.05)	(0.02)	(0.02)
Natural Gas	Wellhead Price		%	2.51	13.51	18.45	14.96	13.55
	Production		%	0.52	3.11	7.05	8.47	8.21
	Pipeline Imports		%					
	Total Demand		%	(0.89)	(4.93)	(7.39)	(6.76)	(6.50)
	Sectoral Demand	AGR	%	(1.40)	(6.82)	(9.52)	(8.33)	(7.73)
		COL	%					
		CRU	%					
		EIS	%	(1.38)	(6.74)	(9.44)	(8.29)	(7.70)
		ELE	%	(0.89)	(5.33)	(8.28)	(7.76)	(7.62)
		GAS	%					
		M_V	%	(0.88)	(4.90)	(7.47)	(6.88)	(6.60)
		MAN	%	(1.24)	(6.26)	(8.87)	(7.82)	(7.31)
		OIL	%	(1.24)	(6.41)	(9.00)	(7.86)	(7.32)
		SRV	%	(0.55)	(3.30)	(5.33)	(5.01)	(4.85)
		TRK	%	(0.32)	(2.04)	(3.66)	(3.68)	(3.66)
		TRN	%	(0.35)	(2.11)	(3.75)	(3.77)	(3.75)
		C	%	(0.41)	(2.75)	(4.55)	(4.34)	(4.20)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 160: Detailed Results for HEUR_SD_HR

Scenario: HEUR_SD_HR								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,973	$18,012	$20,438	$23,021	$25,918
	Consumption		Billion 2010$	$12,442	$14,000	$16,010	$18,181	$20,564
	Investment		Billion 2010$	$2,486	$2,805	$3,178	$3,532	$3,996
Natural Gas	Wellhead Price		2010$ per Mcf	$3.61	$4.61	$4.93	$5.21	$5.59
	Production		Tcf	25.06	27.96	29.83	31.13	32.17
	Exports		Tcf	1.10	4.38	4.38	4.38	4.38
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.23	24.85	25.70	26.89	27.92
	Sectoral Demand	AGR	Tcf	0.15	0.14	0.15	0.15	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.33	3.08	3.18	3.19	3.13
		ELE	Tcf	8.04	7.44	7.59	8.21	8.95
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.18	0.18
		MAN	Tcf	4.27	4.03	4.29	4.49	4.64
		OIL	Tcf	1.27	1.21	1.23	1.32	1.30
		SRV	Tcf	2.49	2.46	2.59	2.70	2.82
		TRK	Tcf	0.48	0.49	0.53	0.57	0.63
		TRN	Tcf	0.22	0.23	0.24	0.27	0.29
		C	Tcf	4.82	4.66	4.74	4.78	4.75
		G	Tcf	0.95	0.93	0.98	1.03	1.07
	Export Revenues [1]		Billion 2010$	$3.69	$18.71	$20.00	$21.15	$22.70
Percentage Change								
Macro	Gross Domestic Product		%	0.08	0.27	0.13	0.08	0.06
	Gross Capital Income		%	(0.07)	(0.34)	(0.26)	(0.20)	(0.17)
	Gross Labor Income		%	(0.06)	(0.25)	(0.19)	(0.15)	(0.13)
	Gross Resource Income		%	17.27	52.53	29.53	20.22	17.92
	Consumption		%	0.10	0.01	(0.02)	(0.01)	(0.01)
	Investment		%	0.11	(0.22)	0.03	0.02	0.03
Natural Gas	Wellhead Price		%	7.96	31.57	20.46	14.95	13.54
	Production		%	1.49	5.68	7.61	8.46	8.20
	Pipeline Imports		%					
	Total Demand		%	(2.71)	(10.38)	(8.12)	(6.77)	(6.50)
	Sectoral Demand	AGR	%	(4.14)	(14.12)	(10.46)	(8.36)	(7.75)
		COL	%					
		CRU	%					
		EIS	%	(4.05)	(13.92)	(10.39)	(8.32)	(7.73)
		ELE	%	(2.75)	(11.20)	(9.08)	(7.76)	(7.62)
		GAS	%					
		M_V	%	(2.64)	(10.24)	(8.20)	(6.90)	(6.60)
		MAN	%	(3.71)	(13.02)	(9.71)	(7.83)	(7.31)
		OIL	%	(3.77)	(13.34)	(9.87)	(7.86)	(7.32)
		SRV	%	(1.70)	(7.15)	(5.87)	(5.01)	(4.85)
		TRK	%	(0.97)	(4.47)	(4.05)	(3.69)	(3.66)
		TRN	%	(1.01)	(4.57)	(4.18)	(3.79)	(3.76)
		C	%	(1.36)	(6.06)	(5.03)	(4.33)	(4.19)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 161: Detailed Results for HEUR_SD_NC

Scenario: HEUR_SD_NC								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$16,017	$18,025	$20,462	$23,039	$25,948
	Consumption		Billion 2010$	$12,447	$14,002	$16,012	$18,184	$20,565
	Investment		Billion 2010$	$2,473	$2,812	$3,177	$3,538	$4,002
Natural Gas	Wellhead Price		2010$ per Mcf	$4.68	$4.98	$5.55	$5.71	$6.41
	Production		Tcf	25.87	28.24	30.81	32.43	34.24
	Exports		Tcf	4.23	5.44	6.72	6.89	8.39
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	23.91	24.07	24.34	25.67	25.99
	Sectoral Demand	AGR	Tcf	0.13	0.13	0.14	0.14	0.14
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	2.91	2.95	2.97	3.02	2.87
		ELE	Tcf	7.32	7.19	7.15	7.78	8.23
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.17	0.17
		MAN	Tcf	3.77	3.88	4.02	4.25	4.28
		OIL	Tcf	1.11	1.17	1.15	1.25	1.20
		SRV	Tcf	2.34	2.41	2.49	2.61	2.67
		TRK	Tcf	0.46	0.48	0.51	0.56	0.60
		TRN	Tcf	0.22	0.22	0.24	0.26	0.28
		C	Tcf	4.58	4.57	4.59	4.64	4.53
		G	Tcf	0.88	0.90	0.94	0.99	1.01
	Export Revenues [1]		Billion 2010$	$18.35	$25.13	$34.58	$36.49	$49.83
Percentage Change								
Macro	Gross Domestic Product		%	0.35	0.34	0.25	0.16	0.18
	Gross Capital Income		%	(0.42)	(0.47)	(0.42)	(0.32)	(0.33)
	Gross Labor Income		%	(0.33)	(0.34)	(0.32)	(0.25)	(0.26)
	Gross Resource Income		%	88.35	70.57	52.78	36.18	41.62
	Consumption		%	0.14	0.02	(0.01)	0.00	0.00
	Investment		%	(0.41)	0.04	0.01	0.18	0.18
Natural Gas	Wellhead Price		%	39.81	42.27	35.75	26.06	30.14
	Production		%	4.78	6.75	11.16	12.97	15.18
	Pipeline Imports		%					
	Total Demand		%	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
	Sectoral Demand	AGR	%	(11.32)	(13.18)	(12.97)	(10.98)	(12.98)
		COL	%	(16.58)	(17.87)	(16.58)	(13.50)	(15.34)
		CRU	%					
		EIS	%					
		ELE	%	(16.19)	(17.66)	(16.46)	(13.45)	(15.30)
		GAS	%	(11.50)	(14.17)	(14.43)	(12.54)	(15.11)
		M_V	%					
		MAN	%	(10.73)	(13.00)	(13.07)	(11.18)	(13.14)
		OIL	%	(14.93)	(16.41)	(15.42)	(12.64)	(14.50)
		SRV	%	(15.45)	(16.82)	(15.63)	(12.69)	(14.54)
		TRK	%	(7.51)	(9.21)	(9.55)	(8.24)	(9.89)
		TRN	%	(4.25)	(5.81)	(6.66)	(6.10)	(7.55)
		C	%	(4.35)	(6.01)	(6.86)	(6.29)	(7.74)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 162: Detailed Results for LEUR_SD_LSS

Scenario: LEUR_SD_LSS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,791	$17,719	$20,060	$22,691	$25,568
	Consumption		Billion 2010$	$12,382	$13,920	$15,861	$18,093	$20,477
	Investment		Billion 2010$	$2,443	$2,757	$3,135	$3,495	$3,956
Natural Gas	Wellhead Price		2010$ per Mcf	$5.73	$6.82	$8.04	$8.33	$9.00
	Production		Tcf	19.60	20.15	20.58	21.13	21.83
	Exports		Tcf	-	0.78	0.86	-	0.19
	Pipeline Imports		Tcf	3.00	2.61	2.37	2.01	1.75
	Total Demand		Tcf	22.60	21.98	22.09	23.14	23.39
	Sectoral Demand	AGR	Tcf	0.16	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.18	3.05	2.96	2.86	2.75
		ELE	Tcf	5.23	4.88	5.08	5.91	6.10
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.16	0.15	0.16	0.16
		MAN	Tcf	3.99	3.88	3.86	3.95	3.99
		OIL	Tcf	1.32	1.37	1.37	1.36	1.38
		SRV	Tcf	2.32	2.33	2.35	2.45	2.54
		TRK	Tcf	0.45	0.45	0.47	0.49	0.51
		TRN	Tcf	0.21	0.21	0.22	0.23	0.24
		C	Tcf	4.68	4.61	4.59	4.63	4.58
		G	Tcf	0.88	0.89	0.90	0.94	0.97
	Export Revenues [1]		Billion 2010$	$0.00	$4.93	$6.41	$0.00	$1.58
Percentage Change								
Macro	Gross Domestic Product		%	0.00	0.01	(0.01)	(0.01)	0.01
	Gross Capital Income		%	0.00	(0.08)	(0.06)	(0.01)	(0.00)
	Gross Labor Income		%	0.00	(0.06)	(0.05)	(0.00)	(0.00)
	Gross Resource Income		%	(0.02)	7.82	3.12	(0.06)	0.43
	Consumption		%	0.02	0.00	(0.01)	0.00	0.00
	Investment		%	0.04	(0.07)	(0.08)	0.08	0.08
Natural Gas	Wellhead Price		%	(0.00)	5.78	2.75	(0.00)	0.42
	Production		%	(0.00)	1.35	2.70	(0.01)	0.60
	Pipeline Imports		%					
	Total Demand		%	(0.00)	(2.28)	(1.42)	(0.01)	(0.25)
	Sectoral Demand	AGR	%	(0.02)	(3.06)	(1.78)	(0.03)	(0.30)
		COL	%					
		CRU	%					
		EIS	%	(0.02)	(3.01)	(1.76)	(0.04)	(0.31)
		ELE	%	0.01	(2.46)	(1.56)	(0.00)	(0.29)
		GAS	%					
		M_V	%	(0.00)	(2.19)	(1.44)	(0.01)	(0.25)
		MAN	%	(0.02)	(2.76)	(1.64)	(0.00)	(0.27)
		OIL	%	0.00	(2.81)	(1.62)	(0.00)	(0.28)
		SRV	%	0.00	(1.70)	(1.14)	(0.01)	(0.21)
		TRK	%	(0.00)	(1.11)	(0.89)	(0.01)	(0.17)
		TRN	%	(0.01)	(1.14)	(0.91)	(0.02)	(0.19)
		C	%	0.02	(1.50)	(1.04)	0.00	(0.19)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 163: Detailed Results for HEUR_SD_LSS_QR

Scenario: HEUR_SD_LSS_QR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,963	$17,976	$20,428	$23,016	$25,915
	Consumption		Billion 2010$	$12,434	$14,003	$16,015	$18,184	$20,566
	Investment		Billion 2010$	$2,484	$2,812	$3,176	$3,531	$3,995
Natural Gas	Wellhead Price		2010$ per Mcf	$3.39	$3.72	$4.43	$4.84	$5.23
	Production		Tcf	24.76	26.89	28.73	29.94	30.97
	Exports		Tcf	0.18	1.10	2.01	2.19	2.19
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.84	27.06	26.97	27.89	28.92
	Sectoral Demand	AGR	Tcf	0.16	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.45	3.46	3.39	3.34	3.26
		ELE	Tcf	8.23	8.16	8.02	8.56	9.33
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.19	0.18	0.18	0.19
		MAN	Tcf	4.41	4.49	4.55	4.68	4.83
		OIL	Tcf	1.31	1.36	1.31	1.38	1.35
		SRV	Tcf	2.53	2.61	2.68	2.78	2.90
		TRK	Tcf	0.48	0.51	0.54	0.59	0.64
		TRN	Tcf	0.22	0.24	0.25	0.27	0.30
		C	Tcf	4.88	4.90	4.89	4.89	4.85
		G	Tcf	0.96	0.99	1.02	1.06	1.10
	Export Revenues [1]		Billion 2010$	$0.57	$3.80	$8.25	$9.83	$10.62
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.07	0.08	0.06	0.05
	Gross Capital Income		%	(0.01)	(0.07)	(0.10)	(0.09)	(0.08)
	Gross Labor Income		%	(0.01)	(0.05)	(0.07)	(0.07)	(0.07)
	Gross Resource Income		%	2.51	10.16	11.70	9.06	8.09
	Consumption		%	0.04	0.03	0.01	0.00	0.00
	Investment		%	0.06	0.04	(0.02)	(0.01)	(0.01)
Natural Gas	Wellhead Price		%	1.19	6.27	8.28	6.86	6.26
	Production		%	0.26	1.63	3.66	4.32	4.18
	Pipeline Imports		%					
	Total Demand		%	(0.43)	(2.41)	(3.56)	(3.29)	(3.17)
	Sectoral Demand	AGR	%	(0.70)	(3.37)	(4.64)	(4.09)	(3.82)
		COL	%					
		CRU	%					
		EIS	%	(0.70)	(3.34)	(4.61)	(4.08)	(3.81)
		ELE	%	(0.43)	(2.60)	(3.99)	(3.78)	(3.73)
		GAS	%					
		M_V	%	(0.45)	(2.42)	(3.63)	(3.38)	(3.25)
		MAN	%	(0.61)	(3.09)	(4.31)	(3.83)	(3.59)
		OIL	%	(0.60)	(3.14)	(4.36)	(3.84)	(3.58)
		SRV	%	(0.26)	(1.59)	(2.53)	(2.41)	(2.34)
		TRK	%	(0.16)	(0.99)	(1.74)	(1.77)	(1.77)
		TRN	%	(0.19)	(1.03)	(1.79)	(1.82)	(1.82)
		C	%	(0.19)	(1.31)	(2.14)	(2.06)	(2.01)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 164: Detailed Results for HEUR_SD_HR_QR

Scenario: HEUR_SD_HR_QR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,974	$18,013	$20,443	$23,027	$25,927
	Consumption		Billion 2010$	$12,444	$14,003	$16,013	$18,184	$20,567
	Investment		Billion 2010$	$2,486	$2,804	$3,178	$3,532	$3,996
Natural Gas	Wellhead Price		2010$ per Mcf	$3.61	$4.61	$4.93	$5.21	$5.59
	Production		Tcf	25.06	27.96	29.83	31.13	32.17
	Exports		Tcf	1.10	4.38	4.38	4.38	4.38
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.22	24.85	25.70	26.89	27.92
	Sectoral Demand	AGR	Tcf	0.15	0.14	0.15	0.15	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.33	3.08	3.18	3.19	3.13
		ELE	Tcf	8.04	7.44	7.59	8.21	8.95
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.18	0.18
		MAN	Tcf	4.27	4.03	4.29	4.48	4.64
		OIL	Tcf	1.27	1.21	1.23	1.32	1.30
		SRV	Tcf	2.49	2.46	2.59	2.70	2.82
		TRK	Tcf	0.48	0.49	0.53	0.57	0.63
		TRN	Tcf	0.22	0.23	0.24	0.27	0.29
		C	Tcf	4.82	4.66	4.75	4.78	4.75
		G	Tcf	0.95	0.93	0.98	1.03	1.07
	Export Revenues [1]		Billion 2010$	$3.68	$18.70	$20.00	$21.15	$22.70
Percentage Change								
Macro	Gross Domestic Product		%	0.09	0.28	0.16	0.11	0.10
	Gross Capital Income		%	(0.07)	(0.34)	(0.26)	(0.20)	(0.18)
	Gross Labor Income		%	(0.06)	(0.25)	(0.19)	(0.15)	(0.14)
	Gross Resource Income		%	17.17	52.44	29.47	20.17	17.87
	Consumption		%	0.12	0.03	(0.00)	0.00	0.01
	Investment		%	0.11	(0.22)	0.02	0.01	0.02
Natural Gas	Wellhead Price		%	7.94	31.55	20.45	14.94	13.53
	Production		%	1.49	5.68	7.61	8.45	8.20
	Pipeline Imports		%					
	Total Demand		%	(2.72)	(10.38)	(8.12)	(6.77)	(6.50)
	Sectoral Demand	AGR	%	(4.17)	(14.15)	(10.50)	(8.40)	(7.79)
		COL	%					
		CRU	%					
		EIS	%	(4.09)	(13.96)	(10.43)	(8.37)	(7.77)
		ELE	%	(2.74)	(11.19)	(9.08)	(7.76)	(7.61)
		GAS	%					
		M_V	%	(2.68)	(10.27)	(8.23)	(6.94)	(6.64)
		MAN	%	(3.73)	(13.03)	(9.73)	(7.85)	(7.33)
		OIL	%	(3.77)	(13.33)	(9.87)	(7.86)	(7.32)
		SRV	%	(1.69)	(7.15)	(5.87)	(5.01)	(4.85)
		TRK	%	(0.98)	(4.48)	(4.06)	(3.70)	(3.68)
		TRN	%	(1.04)	(4.59)	(4.19)	(3.81)	(3.78)
		C	%	(1.34)	(6.04)	(5.01)	(4.31)	(4.17)
1	Export revenues are based on LNG exports net of liquefaction loss.							

APPENDIX D - COMPARISON WITH EIA STUDY

NERA's modeling of shifts in natural gas price, production, and demand are built off an attempt to replicate EIA's price path. This was an important step to ensure that the NERA model output was consistent with the EIA's model. Of particular importance was the ability to replicate EIA's natural gas prices as closely as possible since it is a key driver of macroeconomic impacts. In this process, we ran the exact export scenarios reflected in the EIA Study. We ran Low/Slow, Low/High, High/Slow, and High/Rapid export expansion scenarios for the Reference, High Shale, and Low Shale outlooks. In total we ran 16 EIA consistent scenarios to compare model results. NERA Reference shale gas case scenarios are referenced as NERA_REF_LS, NERA_REF_LR, NERA_REF_HS, and NERA_REF_HR. Similarly, the High Shale and Low Shale case outlook for the NERA Study is referenced as NERA_HEUR_LS, NERA_HEUR_LR, NERA_HEUR_HS, NERA_HEUR_HR, NERA_LEUR_LS, NERA_LEUR_LR, NERA_LEUR_HS, NERA_LEUR_HR, respectively. The corresponding EIA scenarios are referenced as EIA_REF_LS, EIA_REF_LR, EIA_REF_HS, EIA_REF_HR, EIA_HEUR_LS, EIA_HEUR_LR, EIA_HEUR_HS, EIA_HEUR_HR, EIA_LEUR_LS, EIA_LEUR_LR, NERA_LEUR_HS, and NERA_LEUR_HR.

The natural gas supply curve in the NERA model was calibrated to EIA's natural gas supply curve in order to produce a response similar to the EIA High/Rapid scenario for the respective baselines. While the results of this price calibration scenario were nearly duplicated, other macroeconomic scenarios exhibited some differences between the NERA and EIA model runs. These variances are due primarily to differences in the model structure and modeling characteristics such as sectoral price elasticity of demand, supply elasticity, and other behavioral model parameters.

For changes in natural gas prices, the most apparent difference between the EIA and NERA model runs is seen in the High/Slow scenario. This is true for the Reference, High EUR and Low EUR baselines as seen in Figure 165, Figure 166, and Figure 167.These differences arise because we first estimate the implied price elasticity of natural gas supply to replicate the High/Rapid case and then adopt that elasticity for the other scenario runs.

Figure 165: Reference Case Natural Gas Price Percentage Changes

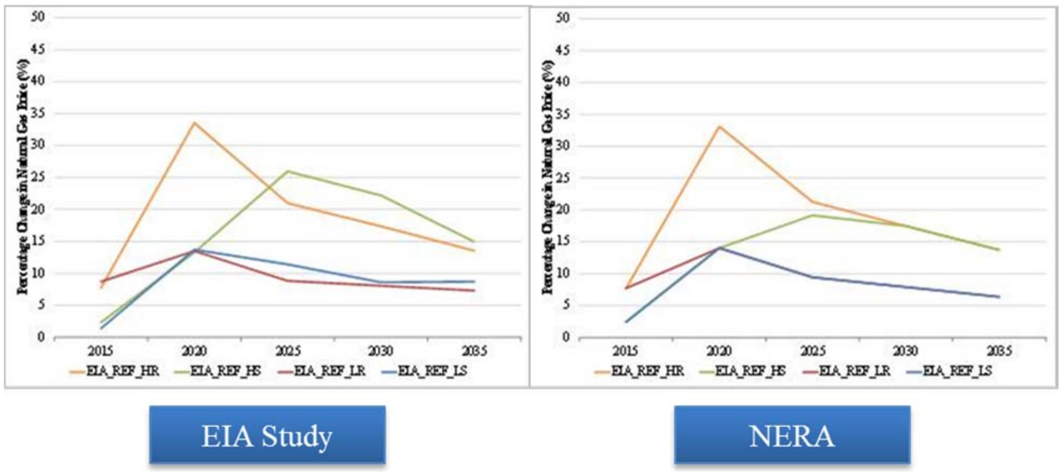


Figure 166: High EUR Natural Gas Price Percentage Changes

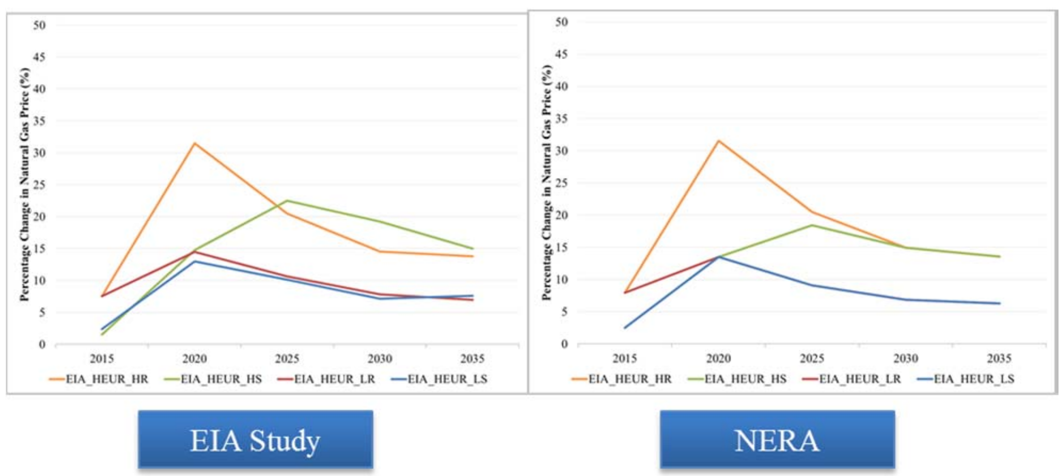
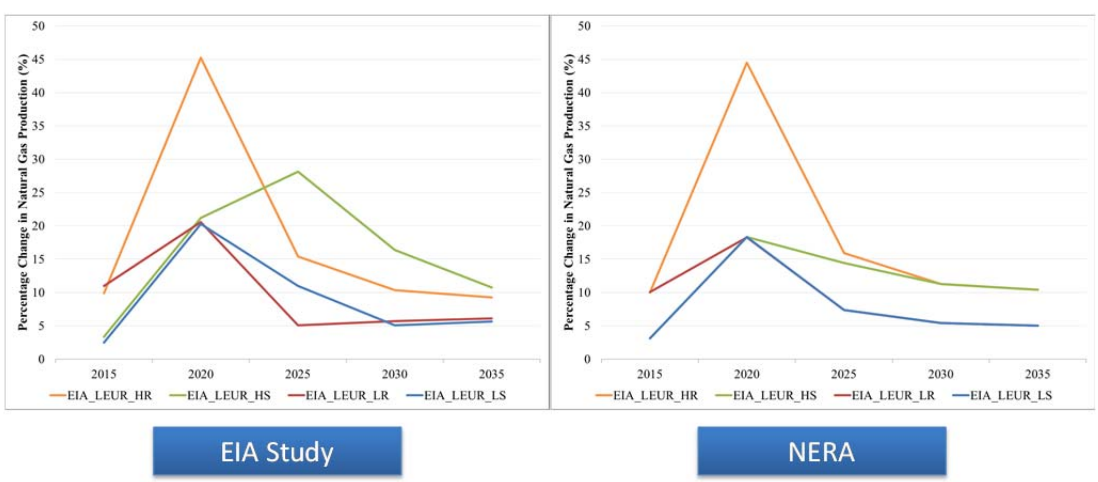


Figure 167: Low EUR Natural Gas Price Percentage Changes



The prices seen in the EIA High/Slow scenario in each baseline case deviate primarily in 2025, but also in 2030, in the range of 5% to 10% higher than the price change seen in the NERA High/Slow scenario. The low/slow scenario also shows small, but noticeable, differentials between the EIA and NERA model runs, particularly with the Reference and Low EUR baselines in 2025. Other than these differences, the general paths of price development in the NERA model runs tend to closely follow those estimated in the EIA study.

Changes in levels of natural gas demand and production show greater differences between the EIA and NERA runs than those seen in price. As briefly mentioned above, and elaborated on to a greater extent below, much of these variances result from the different elasticities used in the models and the overall model structures. The similar paths, but different magnitudes, of demand and production changes compared to the closely matched price changes reveal implied elasticities as a major source of variance. Figure 169 shows the implied supply elasticities for each case in 2015, 2025, and 2035.

The EIA Study assumed four different export scenarios for three different natural gas resources estimates (Reference, High Shale EUR, and Low Shale EUR). The scenarios for each baseline provide sufficient information about natural gas prices and supply quantities to be able to examine the natural gas supply curves. The supply curves are characterized by prices, quantities and the curvature. The current study makes all effort to simulate the EIA's supply curves despite the differences in the model construct. Figure 168 shows the EIA Study and NERA study supply curves for years 2020 and 2035 for the three natural gas resource outlooks.

Examining the curves suggests that the short-run supply curves (2020) are more inelastic than the long-run (2035) supply curves in both studies. The flattening of the supply curves is due to the fact that production and resource constraints are less binding over time. Under the High EUR case, 30 to 34 Tcf of natural gas can be supplied within a price range of \$5 to \$6/Mcf in the long run. However, under the Low EUR case, less natural gas can be supplied at a much higher price.

The EIA Study supply curves are shown as solid lines and the NERA supply curves are shown as dotted lines. Although the long-run supply curves are fairly close to one another, the short-run NERA supply curves are more inelastic. Given the supply curves, for a given change in quantity supplied, natural gas production in NERA model is relatively more price responsive in 2020 than in the EIA Study. The differences in the underlying assumption of the implied supply elasticities in 2020 drive this shape of the supply curve.

Figure 168: Natural Gas Supply Curves

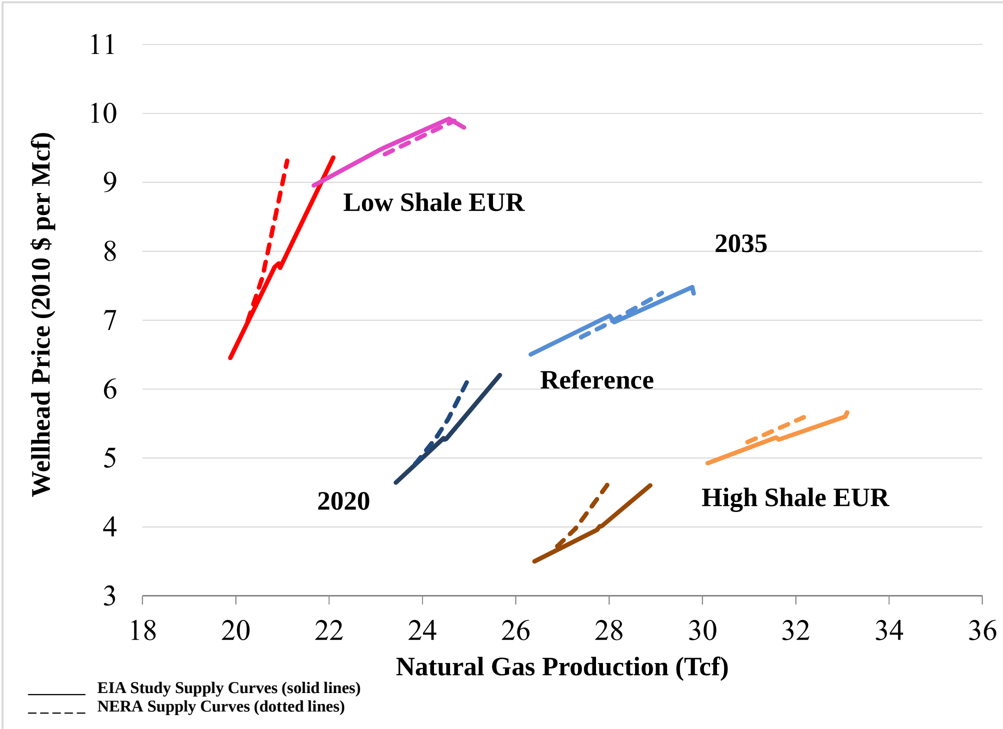
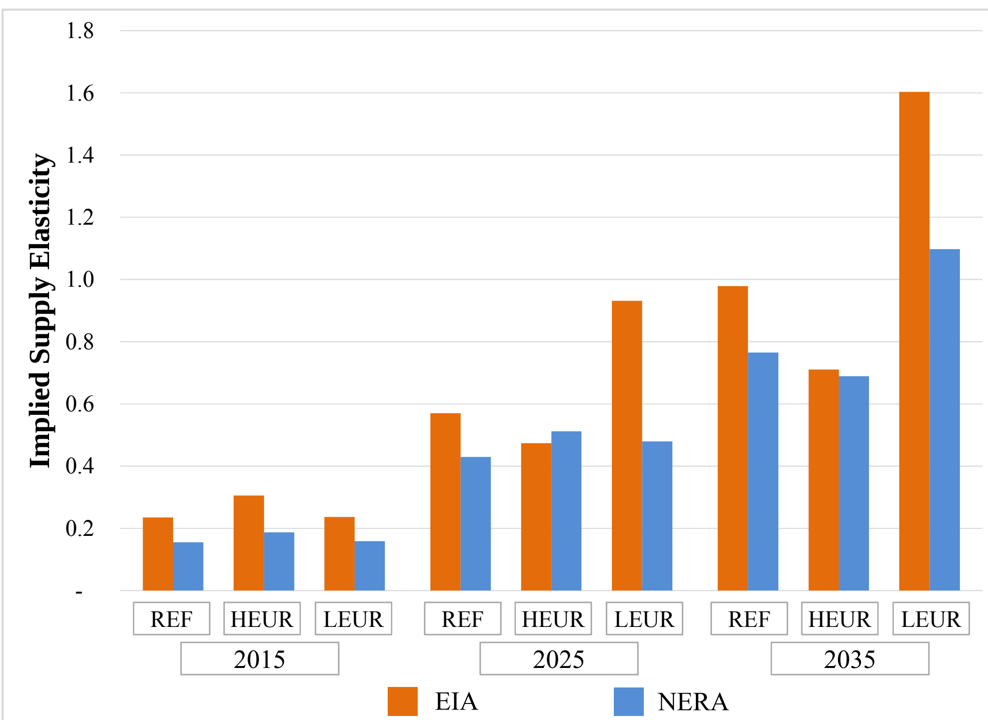


Figure 169: Implied Elasticities of Supply for Cases



Overall, the changes in natural gas demand are dampened in the EIA Study relative to the changes seen in the NERA model results, as seen in Figure 170, Figure 171, and Figure 172. The biggest differences appear to be found in the two rapid scenarios, High/Rapid and Low/Rapid. For each of the baseline cases, the rapid scenarios in the EIA Study show a significantly smaller magnitude of change in demand than they do in the comparable NERA model runs. Similar to the changes in price seen earlier, these differences are most pronounced in 2025 and 2030.

Figure 170: Reference Case Natural Gas Demand Percentage Changes

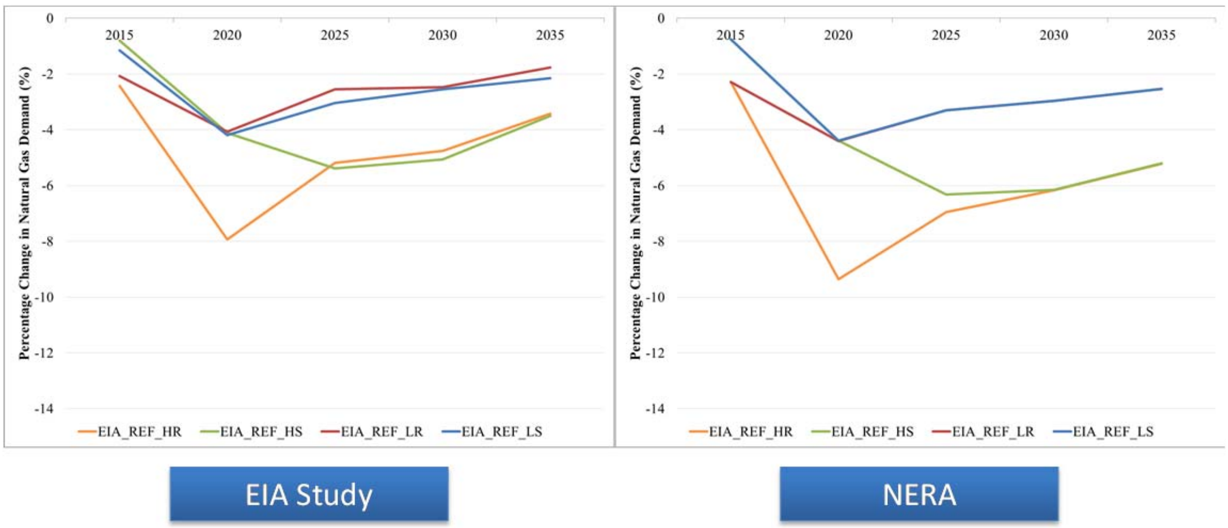


Figure 171: High EUR Natural Gas Demand Percentage Changes

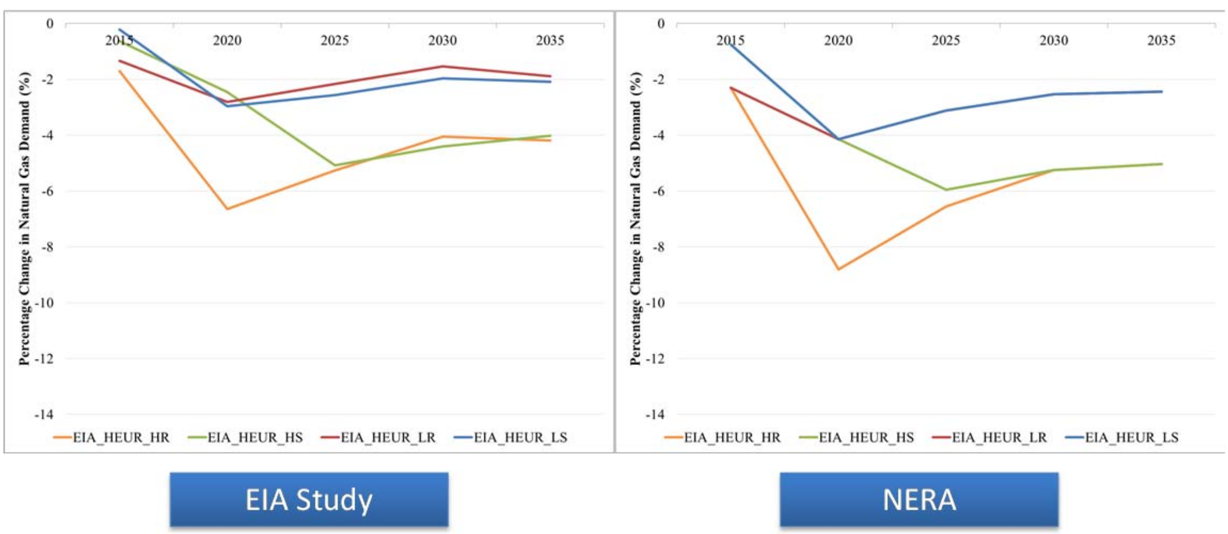
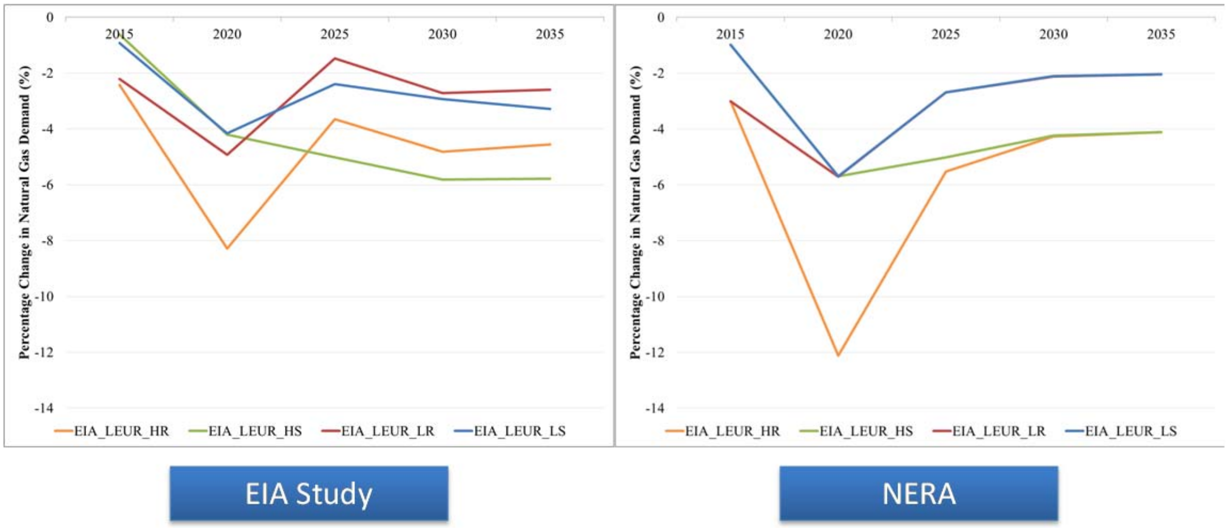


Figure 172: Low EUR Natural Gas Demand Percentage Changes



The results of the Low EUR baseline seen in Figure 172 show the most variance between the EIA and NERA results. In addition to the previously mentioned observation of overall lower magnitude changes in the EIA numbers relative to the NERA numbers and the largest differences being seen in 2025 and 2030, the paths of demand change in the two slow scenarios (High/Slow and Low/Slow) vary in later model years. In the EIA Study the changes in the High/Slow and Low/Slow scenarios get larger from 2025 to 2035 while in the NERA model the changes get smaller towards the end of the model horizon.

Differences between the changes in natural gas production seen in the EIA Study and the NERA modeling results are similar to those seen in demand changes, but in the opposite direction. In this metric, the EIA results show greater magnitudes of change than the NERA results, as can be seen in Figure 173, Figure 174, and Figure 175. This difference can be as large as 3% to 4%, as seen in the 2030 and 2035 years of the Reference Case high scenarios (High/Rapid and High/Slow).

Figure 173: Reference Case Natural Gas Production Percentage Changes

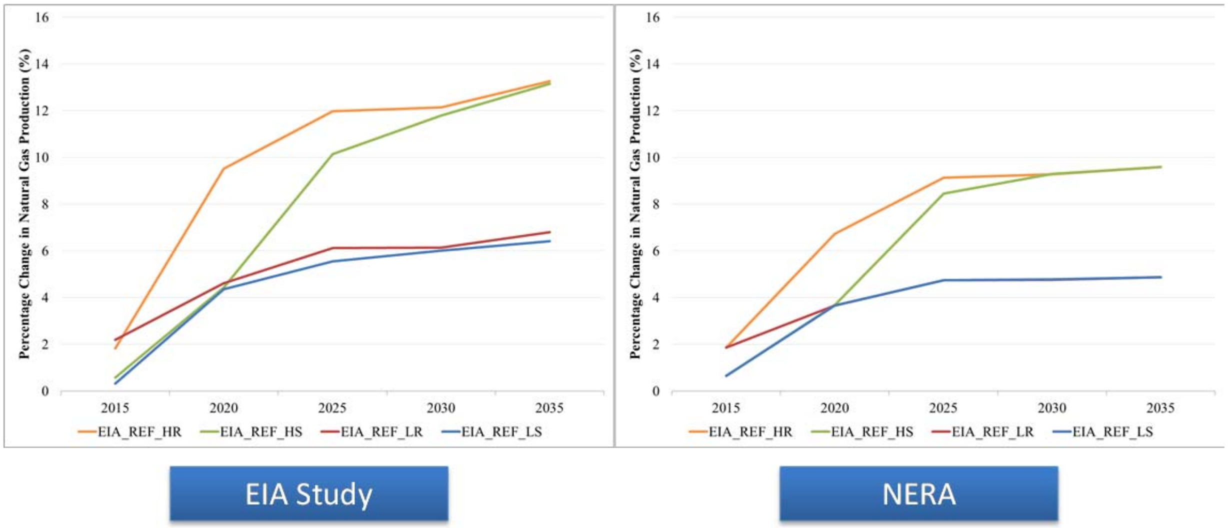


Figure 174: High EUR Natural Gas Production Percentage Changes

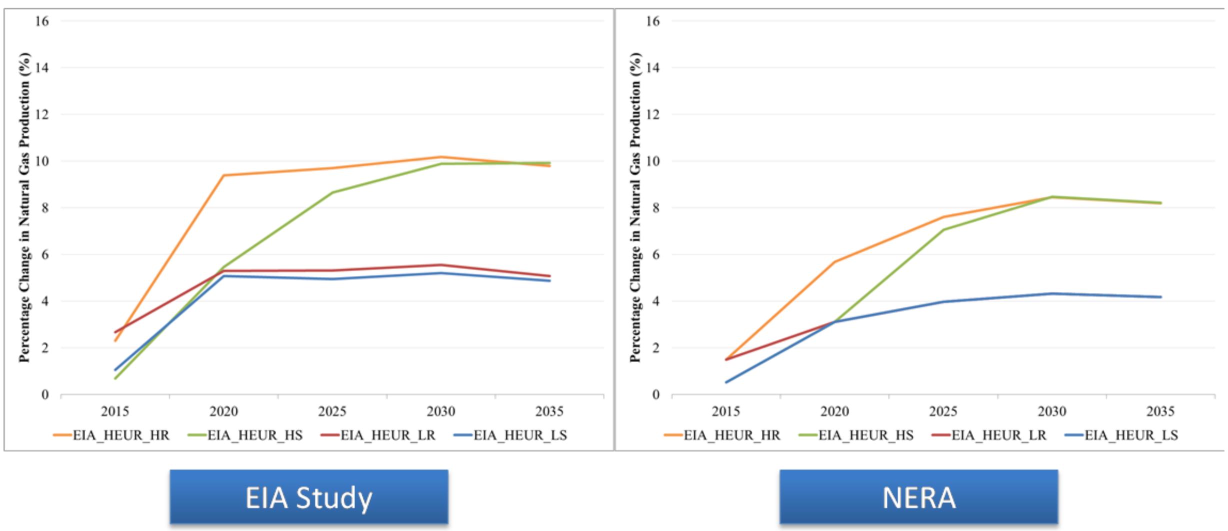
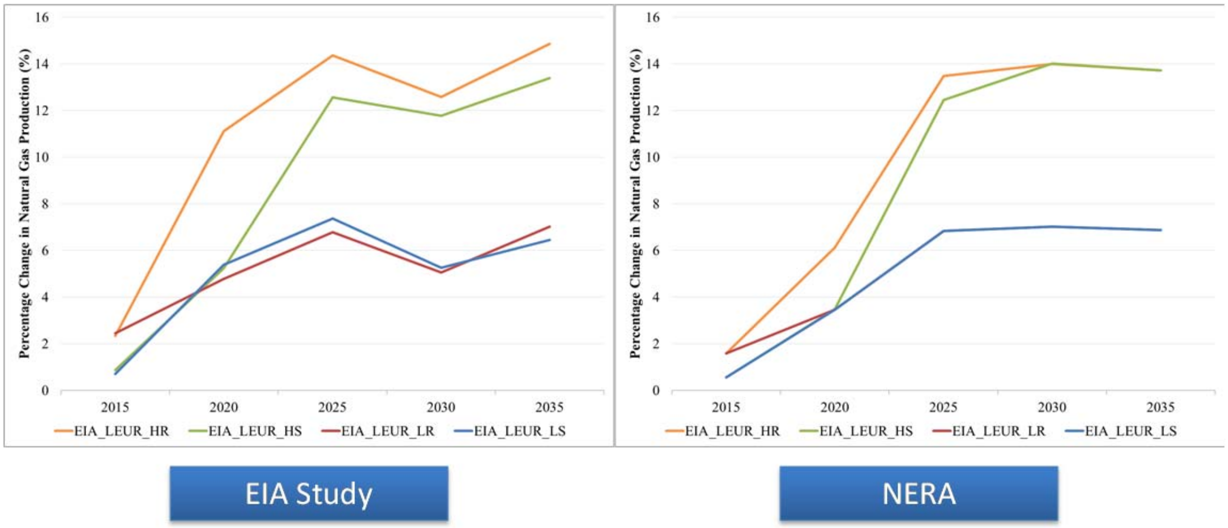


Figure 175: Low EUR Natural Gas Production Percentage Changes



Apart from the overall difference in levels of change seen between the two sets of model results, the general paths and patterns remain fairly similar because they are primarily driven by the level values and the pace of export expansion. The largest differences tend to occur in 2025 and 2030, similar to what is observed in the previous results, but the production changes also show some more variation in 2020.

Comparing changes in natural gas demand at a sectoral level reveal additional similarities and differences between the EIA Study model runs and the NERA model runs. As seen in Figure 176, Figure 177, and Figure 178, while overall levels of natural gas consumption are relatively consistent between the EIA Study and the NERA results, the sectoral components exhibit notable divergences. In particular, the NERA results show much greater demand response in the industrial sector while at the same time much less demand response in the electricity sector. These differences appear to be consistent across all baseline cases. The main reason for the variations in the electricity sector comes from the different way that the sector is modeled. EIA's NEMS model has a detailed bottom-up representation of the electricity sector, while the electricity sector in the NERA model is a nested CES function with limited technologies. This means that NEMS allows for switching from natural gas-based generation to other technology types easily, while the possibility of switching out of natural gas is more limited and controlled in the NERA model.

Figure 176: Reference Case Average Change in Natural Gas Consumed by Sector

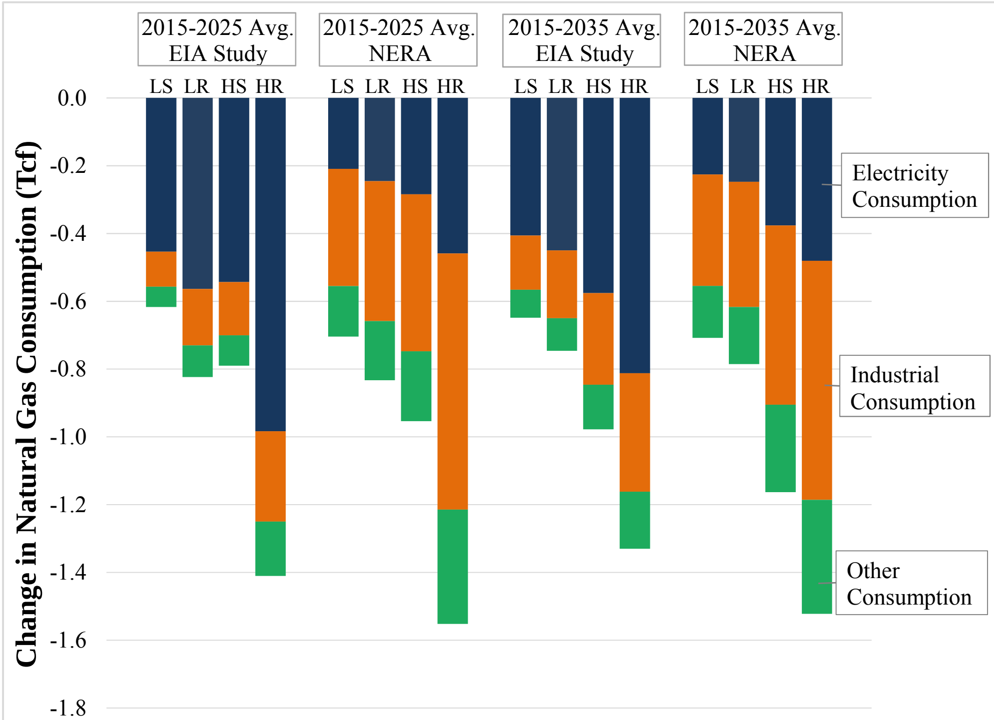


Figure 177: High EUR Average Change in Natural Gas Consumed by Sector

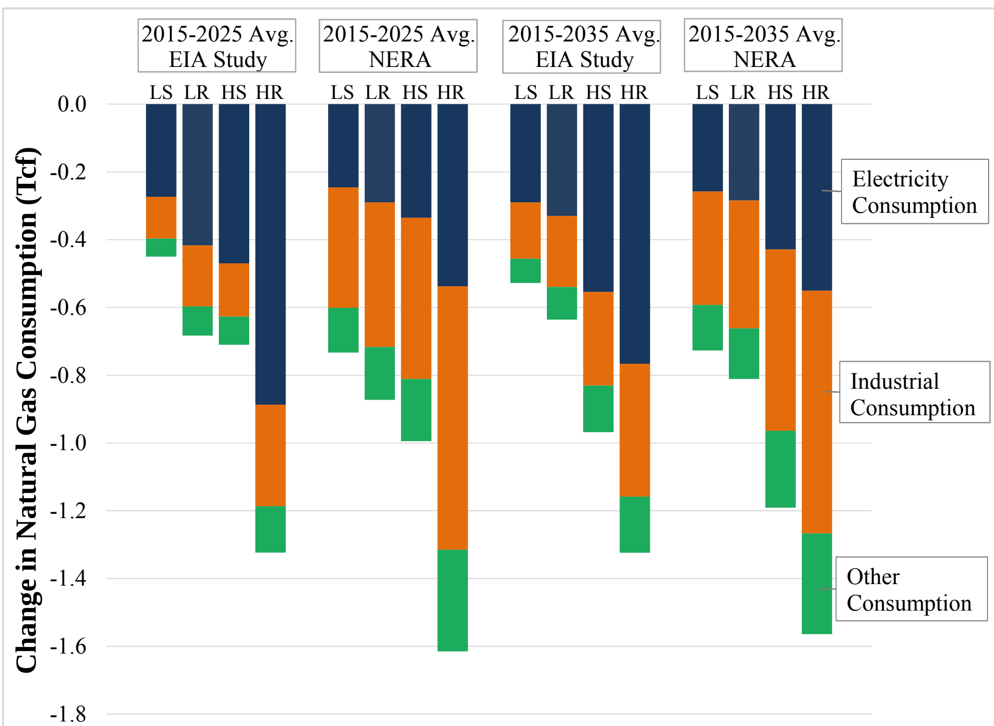
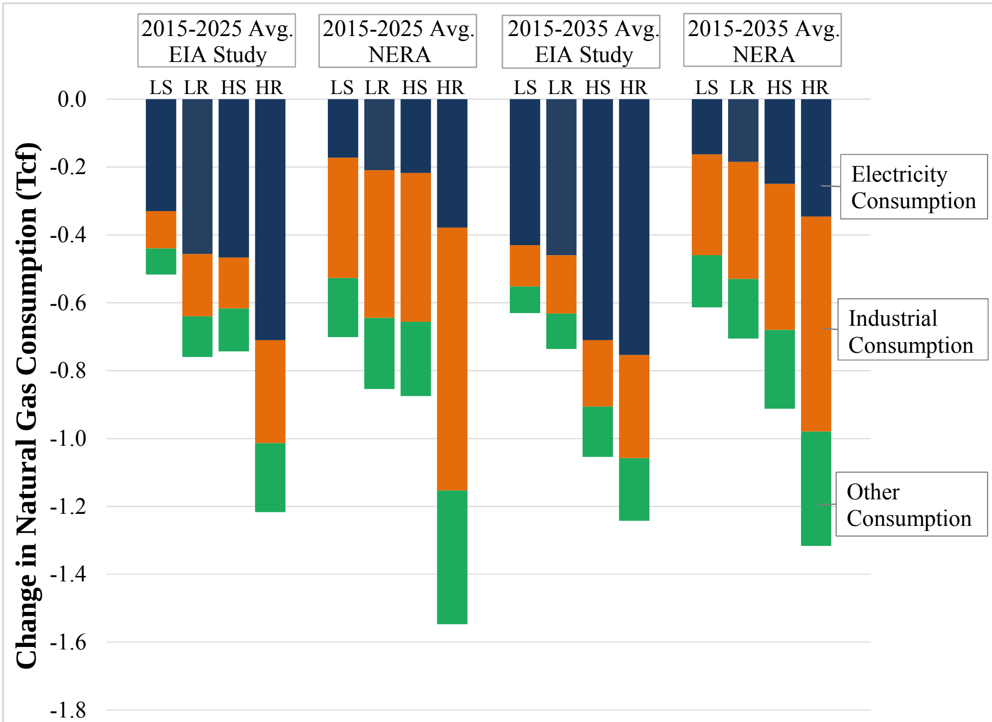


Figure 178: Low EUR Case Average Change in Natural Gas Consumed by Sector



APPENDIX E - FACTORS THAT WE DID NOT INCLUDE IN THE ANALYSIS

There are a number of issues that this study did not address directly. To avoid the misinterpretation of these results or the drawing of unwarranted implications, this section provides brief comments on each.

A. How Will Overbuilding of Export Capacity Affect the Market

This study assumes that the amount of capacity built will match market demand and that the pricing of liquefaction services will be based on long-run marginal costs. Should developers overbuild capacity, there could be pressure on take-or-pay contracts and potentially the margins earned for liquefaction services could be driven below the amount required to cover debt service and expected profits, just as has been the case with petroleum refining margins during periods of slack capacity.

B. Engineering or Infrastructure Limits on How Fast U.S. Liquefaction Capacity Could Be Built

Many of the scenarios investigated in this report assume rates of expansion of liquefaction facilities in the U.S. (and worldwide) that some industry sources believe will strain the capacity of engineering and construction providers. This could drive up the cost of building liquefaction facilities and constrain the rate of expansion to levels lower than those projected in the different scenarios investigated in this report, even if the U.S. resource and global market conditions were as assumed in those scenarios. This possibility requires analysis of the capabilities of the relevant global industries to support rapid construction that could be addressed in later studies.

C. Where Production or Export Terminals Will Be Located

There are proposals for export facilities in the Mid-Atlantic, Pacific Northwest and Canada, all of which could change basis differentials and potentially the location of additional natural gas production, with corresponding implications for regional impacts. To analyze alternative locations of export facilities it would be necessary to repeat both the EIA and the NERA analyses with additional scenarios incorporating demand for natural gas export in different regions.

D. Regional Economic Impacts

Since the EIA assumed that all of the demand for domestic production associated with LNG exports was located in the Gulf region, it was not possible in this study to examine regional impacts on either natural gas prices or economic activity. The Gulf Coast is not necessarily a representative choice given the range of locations now in different applications, so that any attempt to estimate regional impacts would be misleading without more regional specificity in the location of exports.

E. Effects on Different Socioeconomic Groups

Changes in energy prices are often divided into "effects on producers" and "effects on consumers." Although convenient to indicate that there are winners and losers from any market or policy change, this terminology gives limited insight into how the gains and losses are distributed in the economy. The ultimate incidence of all price changes is on individuals and households, for private businesses are all owned ultimately by people. Price changes affect not only the cost of goods and services purchased by households, but also their income from work and investments, transfers from government, and the taxes they pay. More relevant indicators of the distribution of gains and losses include real disposable income by income category, real consumption expenditures by income category, and possibly other measures of distribution by socioeconomic group or geography. This study addresses only the net economic effects of natural gas price changes and improved export revenues, not their distribution.

F. Implications of Foreign Direct Investment in Facilities or Gas Production

In this report it is assumed that all of the investment in liquefaction facilities and in increased natural gas drilling and extraction come from domestic sources. Macroeconomic effects could be different if these facilities and activities were financed by foreign direct investment ("FDI") that was additional to baseline capital flows into the U.S. FDI would largely affect the timing of macroeconomic effects, but quantifying these differences would require consideration of additional scenarios in which the business model was varied.

APPENDIX F – COMPLETE STATEMENT OF WORK

Task Title: Macroeconomic Analysis of LNG Exports

INTRODUCTION:

U.S. shale gas production has increased significantly due to novel hydraulic fracturing and horizontal drilling techniques that have reduced production costs. In the *Annual Energy Outlook 2011* prepared by the Department of Energy's Energy Information Administration, domestic natural gas production grows from 21.0 trillion cubic feet (Tcf) in 2009 to 26.3 Tcf in 2035, while shale gas production grows to 12.2 Tcf in 2035, when it is projected to make up 47 percent of total U.S. production. With this increased volume of domestic natural gas supply available, several companies have applied to the DOE/FE under section 3 of the Natural Gas Act ("NGA")[55] for authorization to export domestic natural gas as LNG to international markets where prices are currently higher. DOE/FE must determine whether applications to export domestically produced LNG to non-free trade agreement ("FTA") countries are consistent with the public interest[56].

To assist with the review of current and potential future applications to DOE/FE to export domestically produced LNG, DOE/FE has requested a natural gas export case study be performed by EIA. The EIA study will provide an independent case study analysis of the impact of increased domestic natural gas demand, as exports, under different incremental demand scenarios using the *AEO 2011* National Energy Modeling System ("NEMS") model. While useful to provide the range of marginal full-cost domestic natural gas production in different scenarios, the EIA NEMS case study will not address the macroeconomic impact of natural gas exports on the U.S. economy. A macroeconomic study that evaluates the impact of LNG exports is needed to more fully examine the impact of LNG exports on the U.S. economy.

PURPOSE:

The purpose of this task is to evaluate the macroeconomic impact of LNG exports using a general equilibrium macroeconomic model of the U.S. economy with an emphasis on the energy sector and natural gas in particular. The general equilibrium model should be developed to incorporate the EIA case study output from NEMS into the natural gas production module in order to calibrate supply cost curves in the macroeconomic model. A macroeconomic case study will be performed to evaluate the impact that LNG exports could have on multiple economic factors, but primarily on U.S. Gross Domestic Product, employment, and real income.

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55 The authority to regulate the imports and exports of natural gas, including liquefied natural gas, under section 3 of the NGA (15 U.S.C. §717b) has been delegated to the Assistant Secretary for FE in Redelegation Order No. 00-002.04E issued on April 29, 2011.

56 Under NGA section 3(c), the import and export of natural gas, including LNG, from and to a nation with which there is in effect a FTA requiring national treatment for trade in natural gas and the import of LNG from other international sources are deemed to be consistent with the public interest and must be granted without modification or delay. Exports of LNG to non FTA countries have not been deemed in the public interest and require a DOE/FE review.

The cases to be run will reflect LNG export volumes increasing by one billion cubic feet per day (Bcf/d) annually until reaching six Bcf/d from a reference case aligned with the *AEO 2011* reference case, a high natural gas resource case, and a low natural gas resource case. Additional cases will be run to evaluate the impact of LNG export volumes that increase much slower and much faster than in the reference case.

Some have commented that U.S. domestic natural gas prices could become disconnected with marginal domestic natural gas production cost and be influenced by higher international market prices. An analysis will be performed to assess whether there is an additional price increase, a "tipping point" price increase, above which exports of LNG have negative impacts on the U.S. economy for several of the cases. The "tipping point" price increase in this analysis could be above the marginal full production cost.

A qualitative report will be prepared that discusses how natural gas prices are formed in the United States and the potential impact that higher international prices could have on the U.S. market. This analysis will include an assessment of whether there are scenarios in which the domestic market could become unlinked to marginal production cost and instead become linked to higher international petroleum-based prices, and whether this could be a short-term or long-term impact, or both.

Initially, a preliminary assessment of the macroeconomic impact of the cases will be prepared and discussed with DOE. This will provide an opportunity for any adjustments to the ultimate cases that will be prepared. Finally, a report will be prepared that discusses the results of the macroeconomic study including topics identified in the Statement of Work.

STATEMENT OF WORK:

The types of analysis and discussions to be conducted include, but are not limited to:

1. U.S. Scenario Analysis (all 16 EIA cases) – Perform a case study on the impacts of a range of LNG export volumes on domestic full production costs under various export volume scenarios. A macroeconomic model will be aligned with the *AEO 2011 Reference Case* and other cases from the DOE/FE-requested EIA case study in different scenarios. Modify a general equilibrium model to calibrate supply cost curves in the macroeconomic model for consistency with EIA NEMS model. The following cases will be run with 5-year intervals through 2035:
    a. **Reference LNG Export Case** – using the macroeconomic model aligned with the *AEO 2011 Reference Case*, show export-related increases in LNG demand equal to the four export scenarios in the EIA study.
    b. Run sensitivity cases related to alternative shale gas resources and recovery economics. These include:
        i. **Low Shale Resource LNG Export Case** - align the macroeconomic model to the *AEO 2011 Low Shale EUR Case*, reflect LNG export volumes over time equal to the four export scenarios in the EIA study.

ii. **High Shale Resource LNG Export Case** – align the macroeconomic model to the *AEO 2011 High Shale EUR Case,* reflect LNG export volumes over time equal to the four export scenarios in the EIA study.

iii. **High Economic Growth LNG Export Case** - align the macroeconomic model to the *AEO 2011 High Economic Growth Case;* reflect LNG export volumes over time equal to the four export scenarios in the EIA study.

c. Run additional sensitivity cases – **Slow Increase in LNG Exports Case** - using the macroeconomic model aligned with the *AEO 2011 Reference Case,* increase LNG exports increase at a slower pace, growing at 0.5 Bcf/d beginning in 2015, until reaching 6 Bcf/d.

2. Preliminary Analysis – Prepare a preliminary analysis of the above cases and provide an initial summary of whether those cases have a positive or negative impact on GDP. After providing that information, discuss the results and determine whether the cases identified are still valid, if some cases should be eliminated, or others added.
3. Worldwide Scenario Analysis – Develop four global LNG market scenarios that define a range of international supply, demand, and market pricing into which U.S. LNG could be exported, as defined below. Using these scenarios, identify potential international demand for U.S. LNG exports, recognizing delivered LNG prices from the United States versus other global sources.
   a. Base case which is calibrated to EIA *International Energy Outlook 2011* for all natural gas
   b. Increased global LNG demand
   c. A restricted global LNG supply scenario in which only liquefaction facilities, of which there is already substantial construction, are completed
   d. Combination of higher international LNG demand and lower international LNG supply
4. Prepare a sensitivity analysis to examine how the ownership of the exported LNG and/or the liquefaction facility affects the U.S. economy.
5. Macroeconomic Report – Prepare a report that discusses the results of the different cases run with the key focus on the macroeconomic impacts of LNG exports. Combine global analysis and U.S. analysis to create new export scenarios that could be supported by the world market (as opposed to the EIA study in which LNG exports were exogenous to the model). Identify and quantify the benefits and drawbacks of LNG exports. Using a macroeconomic model, evaluate the comprehensive impact of all factors on:
   a. U.S. GDP
   b. Employment
   c. Household real income

   The Report will also include a discussion on:

   a. The observations on key cases run

b. Balance of trade impact
c. Expected impact on tax receipts from increased production of natural gas and exports
d. The impact of LNG exports on energy intensive sectors for the scenarios developed
e. Ownership sensitivity analysis
f. Benefits
    - Jobs creation for the nation, not just a region
    - Potential increases in Federal revenues
    - Export earnings and balance of trade
g. Drawbacks
    - Increased natural gas prices
    - Potential for, and impact of, loss of jobs in energy intensive industries
h. GDP Macroeconomic impact
    - Authoritative analysis on GDP of above factors
i. Other relevant analysis and information developed in consultation with DOE/FE

6. The price impacts of natural gas exports will be discussed in a qualitative report that includes how natural gas prices are formed in the United States and the potential impact that higher international prices could have on the U.S. market. This report could be stand-alone or part of the overall macroeconomic study. It will include, at a minimum, a discussion of:
    a. Current market mechanism that establishes U.S. domestic benchmark prices (e.g., Henry Hub)
    b. Potential market mechanism for linkage of domestic markets with higher international markets
    c. The potential linkage of natural gas with petroleum in international markets
7. Assess whether there is some volume of LNG exports, or price increase, above which the United States loses the opportunity for domestic value added industry development from use of low-cost domestic natural gas resources. The discussion will include:
    a. Identification of energy-intensive, trade-exposed industries potentially affected and characterization of their energy costs, employment and value added compared to all manufacturing
    b. Potential impacts on U.S. production of selected natural gas based bulk chemicals
8. After releasing the study results, at the request of DOE, prepare up to three responses to questions raised about the study in an LNG export proceeding or other public release of the study in which these questions or issues are raised

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Regulatory Impact Analysis

Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry

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1 EXECUTIVE SUMMARY

1.1 Background

The U.S. Environmental Protection Agency (EPA) reviewed the New Source Performance Standards (NSPS) for volatile organic compound and sulfur dioxide emissions from Natural Gas Processing Plants. As a result of these NSPS, this proposal amends the Crude Oil and Natural Gas Production source category currently listed under section 111 of the Clean Air Act to include Natural Gas Transmission and Distribution, amends the existing NSPS for volatile organic compounds (VOCs) from Natural Gas Processing Plants, and proposes NSPS for stationary sources in the source categories that are not covered by the existing NSPS. In addition, this proposal addresses the residual risk and technology review conducted for two source categories in the Oil and Natural Gas sector regulated by separate National Emission Standards for Hazardous Air Pollutants (NESHAP). It also proposes standards for emission sources not currently addressed, as well as amendments to improve aspects of these NESHAP related to applicability and implementation. Finally, it addresses provisions in these NESHAP related to emissions during periods of startup, shutdown, and malfunction.

As part of the regulatory process, EPA is required to develop a regulatory impact analysis (RIA) for rules that have costs or benefits that exceed $100 million. EPA estimates the proposed NSPS will have costs that exceed $100 million, so the Agency has prepared an RIA. Because the NESHAP amendments are being proposed in the same rulemaking package (i.e., same Preamble), we have chosen to present the economic impact analysis for the proposed NESHAP amendments within the same document as the NSPS RIA.

This RIA includes an economic impact analysis and an analysis of human health and climate impacts anticipated from the proposed NSPS and NESHAP amendments. We also estimate potential impacts of the proposed NSPS on the national energy economy using the U.S. Energy Information Administration's National Energy Modeling System (NEMS). The engineering compliance costs are annualized using a 7 percent discount rate. This analysis assumes an analysis year of 2015.

Several proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOCs, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One emissions control option, reduced emissions well completions, also recovers saleable hydrocarbon condensates which would otherwise be lost to the environment. The revenues derived from additional natural gas and condensate recovery are expected to offset the engineering costs of implementing the NSPS in the proposed option. In the economic impact and energy economy analyses for the NSPS, we present results for three regulatory options that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

1.2 NSPS Results

For the proposed NSPS, the key results of the RIA follow and are summarized in Table 1-1:

- **Benefits Analysis:** The proposed NSPS is anticipated to prevent significant new emissions, including 37,000 tons of hazardous air pollutants (HAPs), 540,000 tons of VOCs, and 3.4 million tons of methane. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAPs, ozone, and particulate matter (PM), we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, as well as additional natural gas recovery. The methane emissions reductions associated with the proposed NSPS are likely to result in significant climate co-benefits. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of carbon dioxide (CO_2), 510 tons of nitrogen oxides NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital cost of the proposed NSPS will be $740 million. The total annualized engineering costs of the proposed NSPS will be $740 million. When estimated revenues from additional natural gas and condensate recovery are included, the annualized engineering costs of the proposed NSPS are estimated at $-45 million, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf) and condensate price of $70/barrel. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA. The estimated engineering compliance costs that include the product recovery are sensitive to the assumption about the price of the recovered product. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. For example, $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million, given EPA estimates that 180 billion cubic feet of natural gas

will be recovered by implementing the proposed NSPS option. All estimates are in 2008 dollars.

- **Energy System Impacts:** Using the NEMS, when additional natural gas recovery is included, the analysis of energy system impacts for the proposed NSPS shows that domestic natural gas production is likely to increase slightly (about 20 billion cubic feet or 0.1 percent) and average natural gas prices to decrease slightly (about $0.04/Mcf or 0.9 percent at the wellhead for onshore production in the lower 48 states). Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.02/barrel or less than 0.1 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars.
- **Small Entity Analyses:** EPA performed a screening analysis for impacts on small entities by comparing compliance costs to revenues. For the proposed NSPS, we found that there will not be a significant impact on a substantial number of small entities (SISNOSE).
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NSPS is estimated at 230 full-time-equivalent employees. The annual labor requirement to comply with proposed NSPS is estimated at about 2,400 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

Table 1-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Oil and Natural Gas NSPS Regulatory Options in 2015 (millions of 2008$)[1]

	Option 1: Alternative	Option 2: Proposed[4]	Option 3: Alternative
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$19 million	-$45 million	$77 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	17,000 tons of HAPs[5]	37,000 tons of HAPs[5]	37,000 tons of HAPs[5]
	270,000 tons of VOCs	540,000 tons of VOCs	550,000 tons of VOCs
	1.6 million tons of methane[5]	3.4 million tons of methane[5]	3.4 million tons of methane[5]
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

1.3 NESHAP Amendments Results

For the proposed NESHAP amendments, the key results of the RIA follow and are summarized in Table 1-2:

- **Benefits Analysis:** The proposed NESHAP amendments are anticipated to reduce a significant amount of existing emissions, including 1,400 tons of HAPs, 9,200 tons of VOCs, and 4,900 tons of methane. Results from the residual risk assessment indicate that for existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with benzene as the primary cancer risk driver. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAPs, ozone, and PM, we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, and climate effects as well as additional natural gas recovery. The specific control technologies for the proposed NESHAP is anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital costs of the proposed NESHAP amendments to be $52 million. Total annualized engineering costs of the proposed NESHAP amendments are estimated to be $16 million. All estimates are in 2008 dollars.
- **Energy System Impacts:** We did not estimate the energy economy impacts of the proposed NESHAP amendments as the expected costs of the rule are not likely to have estimable impacts on the national energy economy.
- **Small Entity Analyses:** EPA performed a screening analysis for impacts on small entities by comparing compliance costs to revenues. For the proposed NESHAP amendments, we found that there will not be a significant impact on a substantial number of small entities (SISNOSE).
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NESHAP Amendments is estimated at 120 full-time-equivalent employees. The annual labor requirement to comply with proposed NESHAP Amendments is estimated at about 102 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

- **Break-Even Analysis:** A break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health benefits, ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the benefits to exceed the costs. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas, ozone benefits valued at $240 to $1,000 per ton of VOC emissions reduced, and climate co-benefits valued at $110 to $1,400 per short ton of methane reduced. All estimates are in 2008 dollars.

Table 1-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP in 2015 (millions of 2008$)[1]

	Option 1: Proposed (Floor)
Total Monetized Benefits[2]	N/A
Total Costs[3]	$16 million
Net Benefits	N/A
Non-monetized Benefits	1,400 tons of HAPs
	9,200 tons of VOCs[4]
	4,900 tons of methane[4]
	Health effects of HAP exposure
	Health effects of $PM_{2.5}$ and ozone exposure[4]
	Visibility impairment[4]
	Vegetation effects[4]
	Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NESHAP are anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, PM2.5 and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

1.4 Organization of this Report

The remainder of this report details the methodology and the results of the RIA. Section 2 presents the industry profile of the oil and natural gas industry. Section 3 describes the emissions and engineering cost analysis. Section 4 presents the benefits analysis. Section 5 presents statutory and executive order analyses. Section 6 presents a comparison of benefits and costs. Section 7 presents energy system impact, employment impact, and small business impact analyses.

2 INDUSTRY PROFILE

2.1 Introduction

The oil and natural gas industry includes the following five segments: drilling and extraction, processing, transportation, refining, and marketing. The Oil and Natural Gas NSPS and NESHAP amendments propose controls for the oil and natural gas products and processes of the drilling and extraction of crude oil and natural gas, natural gas processing, and natural gas transportation segments.

Most crude oil and natural gas production facilities are classified under NAICS 211: Crude Petroleum and Natural Gas Extraction (211111) and Natural Gas Liquid Extraction (211112). The drilling of oil and natural gas wells is included in NAICS 213111. Most natural gas transmission and storage facilities are classified under NAICS 486210—Pipeline Transportation of Natural Gas. While other NAICS (213112—Support Activities for Oil and Gas Operations, 221210—Natural Gas Distribution, 486110—Pipeline Transportation of Crude Oil, and 541360—Geophysical Surveying and Mapping Services) are often included in the oil and natural gas sector, these are not discussed in detail in the Industry Profile because they are not directly affected by the proposed NSPS and NESHAP amendments.

The outputs of the oil and natural gas industry are inputs for larger production processes of gas, energy, and petroleum products. As of 2009, the Energy Information Administration (EIA) estimates that about 526,000 producing oil wells and 493,000 producing natural gas wells operated in the United States. Domestic dry natural gas production was 20.5 trillion cubic feet (tcf) in 2009, the highest production level since 1970. The leading five natural gas producing states are Texas, Alaska, Wyoming, Oklahoma, and New Mexico. Domestic crude oil production in 2009 was 1,938 million barrels (bbl). The leading five crude oil producing states are Texas, Alaska, California, Oklahoma, and New Mexico.

The Industry Profile provides a brief introduction to the components of the oil and natural gas industry that are relevant to the proposed NSPS and NESHAP Amendments. The purpose is to give the reader a general understanding of the geophysical, engineering, and economic aspects of the industry that are addressed in subsequent economic analysis in this RIA. The Industry Profile relies heavily on background material from the U.S. EPA's "Economic Analysis of Air

Pollution Regulations: Oil and Natural Gas Production" (1996) and the U.S. EPA's "Sector Notebook Project: Profile of the Oil and Gas Extraction Industry" (2000).

2.2 Products of the Crude Oil and Natural Gas Industry

Each producing crude oil and natural gas field has its own unique properties. The composition of the crude oil and natural gas and reservoir characteristics are likely to be different from that of any other reservoir.

2.2.1 Crude Oil

Crude oil can be broadly classified as paraffinic, naphthenic (or asphalt-based), or intermediate. Generally, paraffinic crudes are used in the manufacture of lube oils and kerosene. Paraffinic crudes have a high concentration of straight chain hydrocarbons and are relatively low in sulfur compounds. Naphthenic crudes are generally used in the manufacture of gasolines and asphalt and have a high concentration of olefin and aromatic hydrocarbons. Naphthenic crudes may contain a high concentration of sulfur compounds. Intermediate crudes are those that are not classified in either of the above categories.

Another classification measure of crude oil and other hydrocarbons is by API gravity. API gravity is a weight per unit volume measure of a hydrocarbon liquid as determined by a method recommended by the American Petroleum Institute (API). A heavy or paraffinic crude oil is typically one with API gravity of 20^{o} or less, while a light or naphthenic crude oil, which typically flows freely at atmospheric conditions, usually has API gravity in the range of the high 30's to the low 40's.

Crude oils recovered in the production phase of the petroleum industry may be referred to as live crudes. Live crudes contain entrained or dissolved gases which may be released during processing or storage. Dead crudes are those that have gone through various separation and storage phases and contain little, if any, entrained or dissolved gases.

2.2.2 Natural Gas

Natural gas is a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exists in a gaseous phase or in solution with crude oil or other hydrocarbon liquids in natural underground reservoirs. Natural gas may contain contaminants, such as hydrogen sulfide (H_2S), CO_2, mercaptans, and entrained solids.

Natural gas may be classified as wet gas or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is either natural gas whose water content has been reduced through dehydration or natural gas that contains little or no recoverable liquid hydrocarbons.

Natural gas streams that contain threshold concentrations of H_2S are classified as sour gases. Those with threshold concentrations of CO_2 are classified as acid gases. The process by which these two contaminants are removed from the natural gas stream is called sweetening. The most common sweetening method is amine treating. Sour gas contains a H_2S concentration of greater than 0.25 grain per 100 standard cubic feet, along with the presence of CO_2. Concentrations of H_2S and CO_2, along with organic sulfur compounds, vary widely among sour gases. A majority total onshore natural gas production and nearly all of offshore natural gas production is classified as sweet.

2.2.3 Condensates

Condensates are hydrocarbons in a gaseous state under reservoir conditions, but become liquid in either the wellbore or the production process. Condensates, including volatile oils, typically have an API gravity of 40^{o} or more. In addition, condensates may include hydrocarbon liquids recovered from gaseous streams from various oil and natural gas production or natural gas transmission and storage processes and operations.

2.2.4 Other Recovered Hydrocarbons

Various hydrocarbons may be recovered through the processing of the extracted hydrocarbon streams. These hydrocarbons include mixed natural gas liquids (NGL), natural gasoline, propane, butane, and liquefied petroleum gas (LPG).

2.2.5 Produced Water

Produced water is the water recovered from a production well. Produced water is separated from the extracted hydrocarbon streams in various production processes and operations.

2.3 Oil and Natural Gas Production Processes

2.3.1 Exploration and Drilling

Exploration involves the search for rock formations associated with oil or natural gas deposits and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field and involves the construction of one or more wells from the beginning (called spudding) to either abandonment if no hydrocarbons are found or to well completion if hydrocarbons are found in sufficient quantities.

After the site of a well has been located, drilling commences. A well bore is created by using a rotary drill to drill into the ground. As the well bore gets deeper sections of drill pipe are added. A mix of fluids called drilling mud is released down into the drill pipe then up the walls of the well bore, which removes drill cuttings by taking them to the surface. The weight of the mud prevents high-pressure reservoir fluids from pushing their way out ("blowing out"). The well bore is cased in with telescoping steel piping during drilling to avoid its collapse and to prevent water infiltration into the well and to prevent crude oil and natural gas from contaminating the water table. The steel pipe is cemented by filling the gap between the steel casing and the wellbore with cement.

Horizontal drilling technology has been available since the 1950s. Horizontal drilling facilitates the construction of horizontal wells by allowing for the well bore to run horizontally underground, increasing the surface area of contact between the reservoir and the well bore so that more oil or natural gas can move into the well. Horizontal wells are particularly useful in unconventional gas extraction where the gas is not concentrated in a reservoir. Recent advances have made it possible to steer the drill in different directions (directional drilling) from the surface without stopping the drill to switch directions and allowing for a more controlled and precise drilling trajectory.

Hydraulic fracturing (also referred to as “fracking”) has been performed since the 1940s (U.S. DOE, 2009). Hydraulic fracturing involves pumping fluids into the well under very high pressures in order to fracture the formation containing the resource. Proppant is a mix of sand and other materials that is pumped down to hold the fractures open to secure gas flow from the formation (U.S. EPA, 2004).

2.3.2 Production

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. The major activities of crude oil and natural gas production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities.

Oil and natural gas are found in the pores of rocks and sand (Hyne, 2001). In a conventional source, the oil and natural gas have been pushed out of these pores by water and moved until an impermeable surface had been reached. Because the oil and natural gas can travel no further, the liquids and gases accumulate in a reservoir. Where oil and gas are associated, a gas cap forms above the oil. Natural gas is extracted from a well either because it is associated with oil in an oil well or from a pure natural gas reservoir. Once a well has been drilled to reach the reservoir, the oil and gas can be extracted in different ways depending on the well pressure (Hyne, 2001).

Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as does the ratio of water to hydrocarbons). This increase of gas over oil occurs because natural gas usually is in the top of the oil formation, while the well usually is drilled into the bottom portion to recover most of the liquid. Production sites often handle crude oil and natural gas from more than one well (Hyne, 2001).

Well pressure is required to move the resource up from the well to the surface. During **primary extraction,** pressure from the well itself drives the resource out of the well directly. Well pressure depletes during this process. Typically, about 30 to 35 percent of the resource in the reservoir is extracted this way (Hyne, 2001). The amount extracted depends on the specific well characteristics (such as permeability and oil viscosity). Lacking enough pressure for the resource to surface, gas or water is injected into the well to increase the well pressure and force the resource out (**secondary** or **improved oil recovery).** Finally, **in tertiary extraction** or **enhanced recovery,** gas, chemicals or steam are injected into the well. This can result in recovering up to 60 percent of the original amount of oil in the reservoir (Hyne, 2001).

In contrast to conventional sources, unconventional oil and gas are trapped in rock or sand or, in the case of oil, are found in rock as a chemical substance that requires a further chemical transformation to become oil (U.S. DOE, 2009). Therefore, the resource does not move into a reservoir as in the case with a conventional source. Mining, induced pressure, or heat is required to release the resource. The specific type of extraction method needed depends on the type of formation where the resource is located. Unconventional natural gas resource types relevant for this proposal include:

- **Shale Natural Gas:** Shale natural gas comes from sediments of clay mixed with organic matter. These sediments form low permeability shale rock formations that do not allow the gas to move. To release the gas, the rock must be fragmented, making the extraction process more complex than it is for conventional gas extraction. Shale gas can be extracted by drilling either vertically or horizontally, and breaking the rock using hydraulic fracturing (U.S. DOE, 2009).

- **Tight Sands Natural Gas:** Reservoirs are composed of low-porosity sandstones and carbonate into which natural gas has migrated from other sources. Extraction of the natural gas from tight gas reservoirs is often performed using horizontal wells. Hydraulic fracturing is often used in tight sands (U.S. DOE, 2009).

- **Coalbed Methane:** Natural gas is present in a coal bed due to the activity of microbes in the coal or from alterations of the coal through temperature changes. Horizontal drilling is used but given that coalbed methane reservoirs are frequently associated with underground water reservoirs, hydraulic fracturing is often restricted (Andrews, 2009).

2.3.3 Natural Gas Processing

Natural gas conditioning is the process of removing impurities from the gas stream so that it is of sufficient quality to pass through transportation systems and used by final consumers. Conditioning is not always required. Natural gas from some formations emerges from the well sufficiently pure that it can be sent directly to the pipeline. As the natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or other problems.

The most significant impurity is H_2S, which may or may not be contained in natural gas. H_2S is toxic (and potentially fatal at certain concentrations) to humans and is corrosive for pipes. It is therefore desirable to remove H_2S as soon as possible in the conditioning process.

Another concern is that posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges, especially at cold temperatures (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas in the subsurface. These other gases must be separated from the methane prior to sale. High vapor pressure hydrocarbons that are liquids at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately.

Dehydration removes water from the gas stream. Three main approaches toward dehydration are the use of a liquid or solid desiccant, and refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration. The glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract the water molecules. The solids can be regenerated simply by heating them above the boiling point of water. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing at or near the well.

Sweetening is the procedure in which H_2S and sometimes CO_2 are removed from the gas stream. The most common method is amine treatment. In this process, the gas stream is exposed to an amine solution, which will react with the H_2S and separate them from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product.

2.3.4 Natural Gas Transmission and Distribution

After processing, natural gas enters a network of compressor stations, high-pressure transmission pipelines, and often-underground storage sites. Compressor stations are any facility which supplies energy to move natural gas at increased pressure in transmission pipelines or into underground storage. Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure. Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

2.4 Reserves and Markets

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, has historically been consumed close to where it is produced. However, as pipeline infrastructure and LNG trade expand, natural gas is increasingly a national and international commodity. The following subsections provide historical and forecast data on the U.S. reserves, production, consumption, and foreign trade of crude oil and natural gas.

2.4.1 Domestic Proved Reserves

Table 2-1 shows crude oil and natural gas proved reserves, inferred reserves, and undiscovered and total technically recoverable resources as of 2007. According to EIA[1], these concepts are defined as:

- **Proved reserves:** estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.

- **Inferred reserves:** the estimate of total volume recovery from known crude oil or natural gas reservoirs or aggregation of such reservoirs is expected to increase during the time between discovery and permanent abandonment.

- **Technically recoverable:** resources that are producible using current technology without reference to the economic viability of production.

The sum of proved reserves, inferred reserves, and undiscovered technically recoverable resources equal the total technically recoverable resources. As seen in Table 2-1, as of 2007, proved domestic crude oil reserves accounted for about 12 percent of the totally technically recoverable crude oil resources.

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[1] U.S. Department of Energy, Energy Information Administration, Glossary of Terms <http://www.eia.doe.gov/glossary/index.cfm?id=P> Accessed 12/21/2010.

Table 2-1 Technically Recoverable Crude Oil and Natural Gas Resource Estimates, 2007

Region	Proved Reserves	Inferred Reserves	Undiscovered Technically Recoverable Resources	Total Technically Recoverable Resources
Crude Oil and Lease Condensate (billion bbl)				
48 States Onshore	14.2	48.3	25.3	87.8
48 States Offshore	4.4	10.3	47.2	61.9
Alaska	4.2	2.1	42.0	48.3
Total U.S.	22.8	60.7	114.5	198.0
Dry Natural Gas (tcf)				
Conventionally Reservoired Fields	194.0	671.3	760.4	1625.7
48 States Onshore Non-Associated Gas	149.0	595.9	144.1	889.0
48 States Offshore Non-Associated Gas	12.4	50.7	233.0	296.0
Associated-Dissolved Gas	20.7		117.2	137.9
Alaska	11.9	24.8	266.1	302.8
Shale Gas and Coalbed Methane	43.7	385	64.2	493.0
Total U.S.	237.7	1056.3	824.6	2118.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Inferred reserves for associated-dissolved natural gas are included in "Undiscovered Technically Recoverable Resources." Totals may not sum due to independent rounding.

Proved natural gas reserves accounted for about 11 percent of the totally technically recoverable natural gas resources. Significant proportions of these reserves exist in Alaska and offshore areas.

Table 2-2 and Figure 2-1 show trends in crude oil and natural gas production and reserves from 1990 to 2008. In Table 2-2, proved ultimate recovery equals the sum of cumulative production and proved reserves. While crude oil and natural gas are nonrenewable resources, the table shows that proved ultimate recovery rises over time as new discoveries become economically accessible. Reserves growth and decline is also partly a function of exploration activities, which are correlated with oil and natural gas prices. For example, when oil prices are high there is more of an incentive to use secondary and tertiary recovery, as well as to develop unconventional sources.

Table 2-2 Crude Oil and Natural Gas Cumulative Domestic Production, Proved Reserves, and Proved Ultimate Recovery, 1977-2008

	Crude Oil and Lease Condensate (million bbl)			Dry Natural Gas (bcf)		
Year	Cumulative Production	Proved Reserves	Proved Ultimate Recovery	Cumulative Production	Proved Reserves	Proved Ultimate Recovery
1990	158,175	27,556	185,731	744,546	169,346	913,892
1991	160,882	25,926	186,808	762,244	167,062	929,306
1992	163,507	24,971	188,478	780,084	165,015	945,099
1993	166,006	24,149	190,155	798,179	162,415	960,594
1994	168,438	23,604	192,042	817,000	163,837	980,837
1995	170,832	23,548	194,380	835,599	165,146	1,000,745
1996	173,198	23,324	196,522	854,453	166,474	1,020,927
1997	175,553	23,887	199,440	873,355	167,223	1,040,578
1998	177,835	22,370	200,205	892,379	164,041	1,056,420
1999	179,981	23,168	203,149	911,211	167,406	1,078,617
2000	182,112	23,517	205,629	930,393	177,427	1,107,820
2001	184,230	23,844	208,074	950,009	183,460	1,133,469
2002	186,327	24,023	210,350	968,937	186,946	1,155,883
2003	188,400	23,106	211,506	988,036	189,044	1,177,080
2004	190,383	22,592	212,975	1,006,564	192,513	1,199,077
2005	192,273	23,019	215,292	1,024,638	204,385	1,229,023
2006	194,135	22,131	216,266	1,043,114	211,085	1,254,199
2007	196,079	22,812	218,891	1,062,203	237,726	1,299,929
2008	197,987	20,554	218,541	1,082,489	244,656	1,327,145

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

However, annual production as a percentage of proved reserves has declined over time for both crude oil and natural gas, from above 10 percent in the early 1990s to 8 to 9 percent from 2006 to 2008 for crude oil and from above 11 percent during the 1990s to about 8 percent from 2008 to 2008 for natural gas.

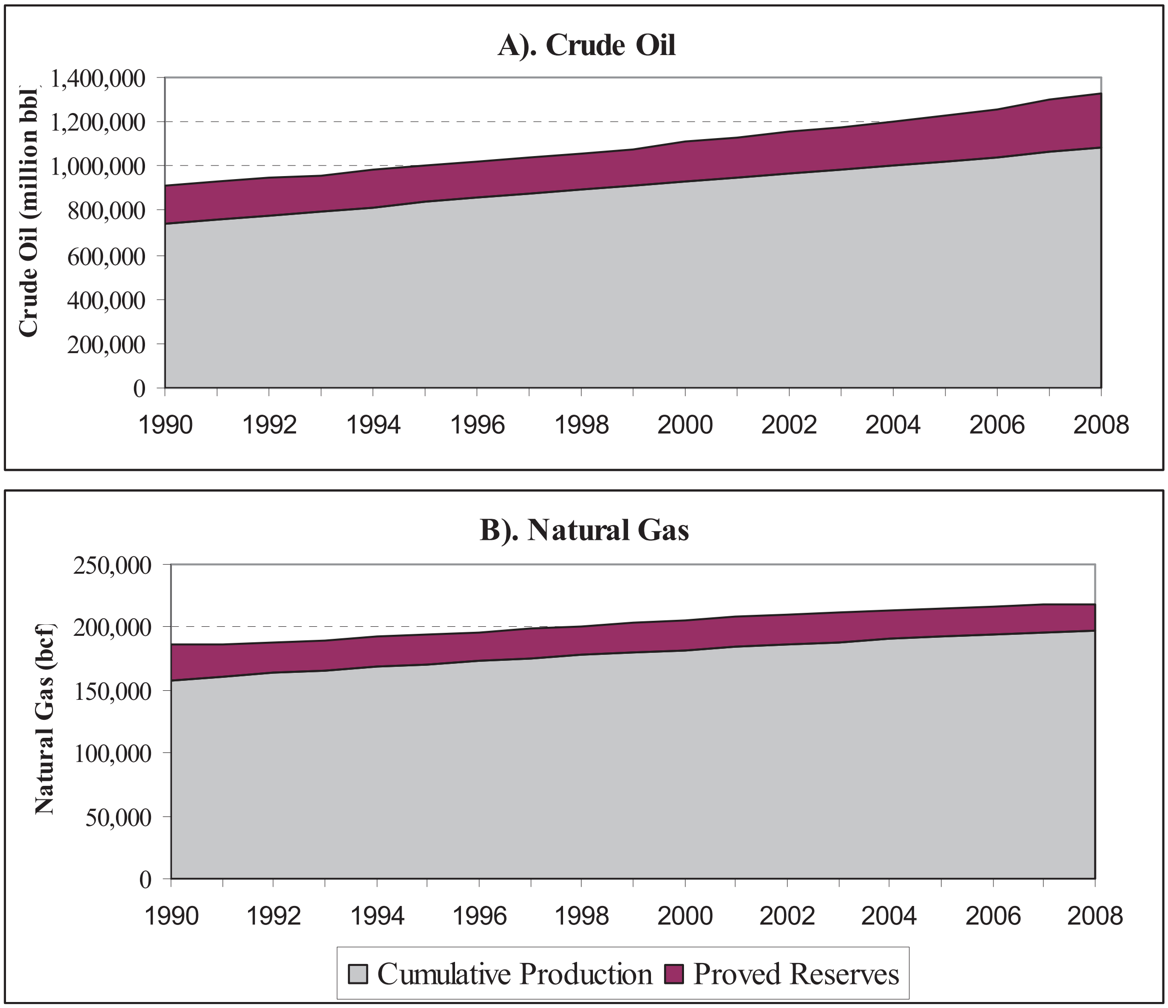

Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2008. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2008

Table 2-3 presents the U.S. proved reserves of crude oil and natural gas by state or producing area as of 2008. Four areas currently account for 77 percent of the U.S. total proved reserves of crude oil, led by Texas and followed by U.S. Federal Offshore, Alaska, and California. The top five states (Texas, Wyoming, Colorado, Oklahoma, and New Mexico) account for about 69 percent of the U.S. total proved reserves of natural gas.

Table 2-3 Crude Oil and Dry Natural Gas Proved Reserves by State, 2008

State/Region	Crude Oil (million bbls)	Dry Natural Gas (bcf)	Crude Oil (percent of total)	Dry Natural Gas (percent of total)
Alaska	3,507	7,699	18.3	3.1
Alabama	38	3,290	0.2	1.3
Arkansas	30	5,626	0.2	2.3
California	2,705	2,406	14.1	1.0
Colorado	288	23,302	1.5	9.5
Florida	3	1	0.0	0.0
Illinois	54	0	0.3	0.0
Indiana	15	0	0.1	0.0
Kansas	243	3,557	1.3	1.5
Kentucky	17	2,714	0.1	1.1
Louisiana	388	11,573	2.0	4.7
Michigan	48	3,174	0.3	1.3
Mississippi	249	1,030	1.3	0.4
Montana	321	1,000	1.7	0.4
Nebraska	8	0	0.0	0.0
New Mexico	654	16,285	3.4	6.7
New York	0	389	0.0	0.2
North Dakota	573	541	3.0	0.2
Ohio	38	985	0.2	0.4
Oklahoma	581	20,845	3.0	8.5
Pennsylvania	14	3,577	0.1	1.5
Texas	4,555	77,546	23.8	31.7
Utah	286	6,643	1.5	2.7
Virginia	0	2,378	0.0	1.0
West Virginia	23	5,136	0.1	2.1
Wyoming	556	31,143	2.9	12.7
Miscellaneous States	24	270	0.1	0.1
U.S. Federal Offshore	3,903	13,546	20.4	5.5
Total Proved Reserves	**19,121**	**244,656**	100.0	100.0

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Totals may not sum due to independent rounding.

2.4.2 Domestic Production

Domestic oil production is currently in a state of decline that began in 1970. Table 2-4 shows U.S. production in 2009 at 1938 million bbl per year, the highest level since 2004. However, annual domestic production of crude oil has dropped by almost 750 million bbl since 1990.

Table 2-4 Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average First Purchase Price

Year	Total Production (million bbl)	Producing Wells (1000s)	Avg. Well Productivity (bbl/well)	U.S. Average First Purchase Price/Barrel (2005 dollars)
1990	2,685	602	4,460	27.74
1991	2,707	614	4,409	22.12
1992	2,625	594	4,419	20.89
1993	2,499	584	4,279	18.22
1994	2,431	582	4,178	16.51
1995	2,394	574	4,171	17.93
1996	2,366	574	4,122	22.22
1997	2,355	573	4,110	20.38
1998	2,282	562	4,060	12.71
1999	2,147	546	3,932	17.93
2000	2,131	534	3,990	30.14
2001	2,118	530	3,995	24.09
2002	2,097	529	3,964	24.44
2003	2,073	513	4,042	29.29
2004	1,983	510	3,889	38.00
2005	1,890	498	3,795	50.28
2006	1,862	497	3,747	57.81
2007	1,848	500	3,697	62.63
2008	1,812	526	3,445	86.69
2009	1,938	526	3,685	51.37*

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

First purchase price represents the average price at the lease or wellhead at which domestic crude is purchased. * 2009 Oil price is preliminary

Average well productivity has also decreased since 1990 (Table 2-4 and Figure 2-2). These production and productivity decreases are in spite of the fact that average first purchase prices have shown a generally increasing trend. The exception to this general trend occurred in 2008 and 2009 when the real price increased up to 86 dollars per barrel and production in 2009 increased to almost 2 million bbl of oil.

Annual production of natural gas from natural gas wells has increased nearly 3000 bcf from the 1990 to 2009 (Table 2-5). Natural gas extracted from crude oil wells (associated natural gas) has remained more or less constant for the last twenty years. Coalbed methane has become a significant component of overall gas withdrawals in recent years.

Table 2-5 Natural Gas Production and Well Productivity, 1990-2009

	Natural Gas Gross Withdrawals (bcf)					Natural Gas Well Productivity	
Year	Natural Gas Wells	Crude Oil Wells	Coalbed Methane Wells	Total	Dry Gas Production*	Producing Wells (no.)	Avg. Productivity per Well (MMcf)
1990	16,054	5,469	NA	21,523	17,810	269,100	59.657
1991	16,018	5,732	NA	21,750	17,698	276,337	57.964
1992	16,165	5,967	NA	22,132	17,840	275,414	58.693
1993	16,691	6,035	NA	22,726	18,095	282,152	59.157
1994	17,351	6,230	NA	23,581	18,821	291,773	59.468
1995	17,282	6,462	NA	23,744	18,599	298,541	57.888
1996	17,737	6,376	NA	24,114	18,854	301,811	58.770
1997	17,844	6,369	NA	24,213	18,902	310,971	57.382
1998	17,729	6,380	NA	24,108	19,024	316,929	55.938
1999	17,590	6,233	NA	23,823	18,832	302,421	58.165
2000	17,726	6,448	NA	24,174	19,182	341,678	51.879
2001	18,129	6,371	NA	24,501	19,616	373,304	48.565
2002	17,795	6,146	NA	23,941	18,928	387,772	45.890
2003	17,882	6,237	NA	24,119	19,099	393,327	45.463
2004	17,885	6,084	NA	23,970	18,591	406,147	44.036
2005	17,472	5,985	NA	23,457	18,051	425,887	41.025
2006	17,996	5,539	NA	23,535	18,504	440,516	40.851
2007	17,065	5,818	1,780	24,664	19,266	452,945	37.676
2008	18,011	5,845	1,898	25,754	20,286	478,562	37.636
2009	18,881	5,186	2,110	26,177	20,955	495,697	38.089

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**
*Dry gas production is gas production after accounting for gas used repressurizing wells, the removal of nonhydrocarbon gases, vented and flared gas, and gas used as fuel during the production process.

The number of wells producing natural gas wells has nearly doubled between 1990 and 2009 (Figure 2-2). While the number of producing wells has increased overall, average well productivity has declined, despite improvements in exploration and gas well stimulation technologies.

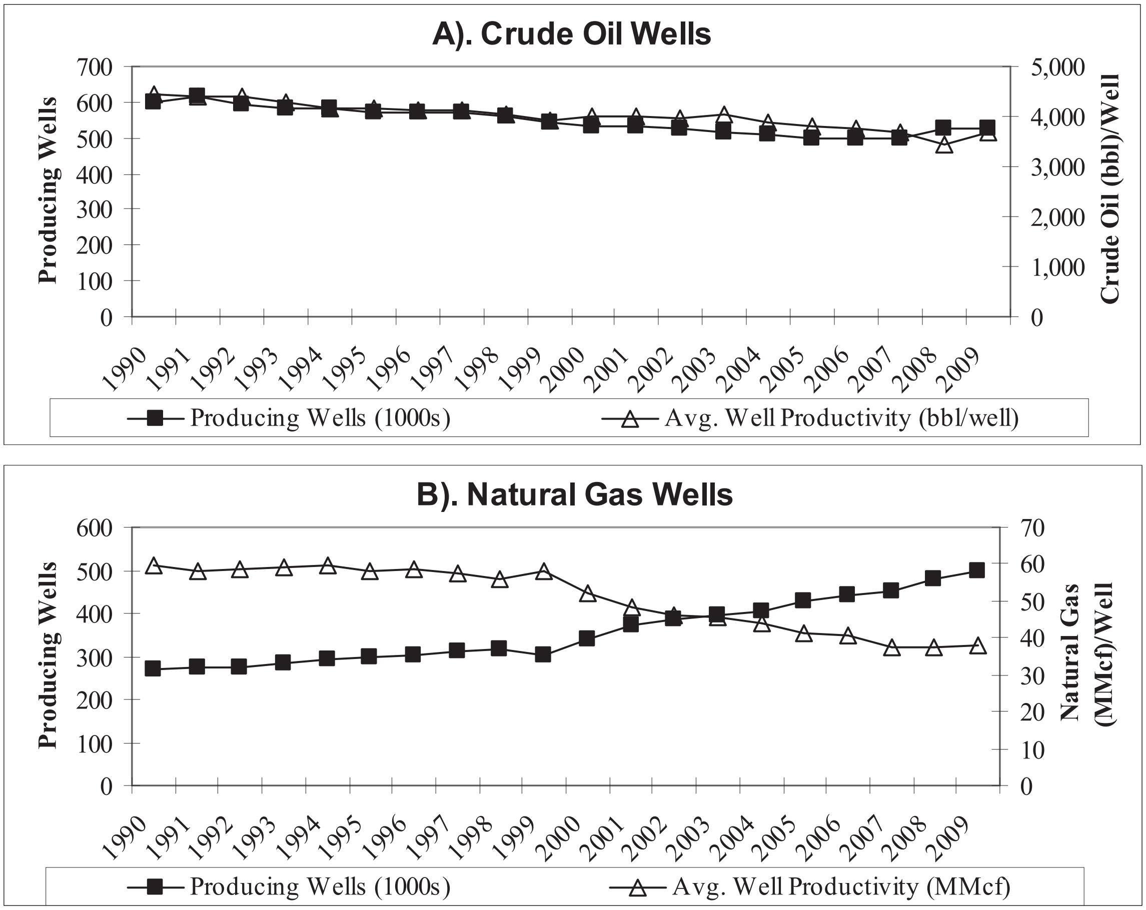

Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2009. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2009.

Domestic exploration and development for oil has continued during the last two decades. From 2002 to 2009, crude oil well drilling showed significant increases, although the 1992-2001 period showed relatively low levels of crude drilling activity compared to periods before and after (Table 2-6). The drop in 2009 showed a departure from this trend, likely due to the recession experienced in the U.S.

Meanwhile, natural gas drilling has increased significantly during the 1990-2009 period. Like crude oil drilling, 2009 saw a relatively low level of natural gas drillings. The success rate of wells (producing wells versus dry wells) has also increased gradually over time from 75 percent in 1990, to 86 percent in 2000, to 90 percent in 2009 (Table 2-6). The increasing success rate reflects improvements in exploration technology, as well as technological improvements in well drilling and completion. Similarly, well average depth has also increased by during this period (Table 2-6).

Table 2-6 Crude Oil and Natural Gas Exploratory and Development Wells and Average Depth, 1990-2009

	Wells Drilled					
Year	Crude Oil	Natural Gas	Dry Holes	Total	Successful Wells (percent)	Average Depth (ft)
1990	12,800	11,227	8,237	32,264	75	4,841
1991	12,542	9,768	7,476	29,786	75	4,872
1992	9,379	8,149	5,857	23,385	75	5,138
1993	8,828	9,829	6,093	24,750	75	5,407
1994	7,334	9,358	5,092	21,784	77	5,736
1995	8,230	8,081	4,813	21,124	77	5,560
1996	8,819	9,015	4,890	22,724	79	5,573
1997	11,189	11,494	5,874	28,557	79	5,664
1998	7,659	11,613	4,763	24,035	80	5,722
1999	4,759	11,979	3,554	20,292	83	5,070
2000	8,089	16,986	4,134	29,209	86	4,942
2001	8,880	22,033	4,564	35,477	87	5,077
2002	6,762	17,297	3,728	27,787	87	5,223
2003	8,104	20,685	3,970	32,759	88	5,418
2004	8,764	24,112	4,053	36,929	89	5,534
2005E	10,696	28,500	4,656	43,852	89	5,486
2006E	13,289	32,878	5,183	51,350	90	5,537
2007E	13,564	33,132	5,121	51,817	90	5,959
2008E	17,370	34,118	5,726	57,214	90	6,202
2009E	13,175	19,153	3,537	35,865	90	6,108

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Values for 2005-2009 are estimates.

Produced water is an important byproduct of the oil and natural gas industry, as management, including reuse and recycling, of produced water can be costly and challenging. Texas, California, Wyoming, Oklahoma, and Kansas were the top five states in terms of produced water volumes in 2007 (Table 2-7). These estimates do not include estimates of flowback water from hydraulic fracturing activities (ANL 2009).

Table 2-7 U.S. Onshore and Offshore Oil, Gas, and Produced Water Generation, 2007

State	Crude Oil (1000 bbl)	Total Gas (bcf)	Produced Water (1000 bbl)	Total Oil and Natural Gas (1000 bbls oil equivalent)	Barrels Produced Water per Barrel Oil Equivalent
Alabama	5,028	285	119,004	55,758	2.13
Alaska	263,595	3,498	801,336	886,239	0.90
Arizona	43	1	68	221	0.31
Arkansas	6,103	272	166,011	54,519	3.05
California	244,000	312	2,552,194	299,536	8.52
Colorado	2,375	1,288	383,846	231,639	1.66
Florida	2,078	2	50,296	2,434	20.66
Illinois	3,202	no data	136,872	3,202	42.75
Indiana	1,727	4	40,200	2,439	16.48
Kansas	36,612	371	1,244,329	102,650	12.12
Kentucky	3,572	95	24,607	20,482	1.20
Louisiana	52,495	1,382	1,149,643	298,491	3.85
Michigan	5,180	168	114,580	35,084	3.27
Mississippi	20,027	97	330,730	37,293	8.87
Missouri	80	no data	1,613	80	20.16
Montana	34,749	95	182,266	51,659	3.53
Nebraska	2,335	1	49,312	2,513	19.62
Nevada	408	0	6,785	408	16.63
New Mexico	59,138	1,526	665,685	330,766	2.01
New York	378	55	649	10,168	0.06
North Dakota	44,543	71	134,991	57,181	2.36
Ohio	5,422	86	6,940	20,730	0.33
Oklahoma	60,760	1,643	2,195,180	353,214	6.21
Pennsylvania	1,537	172	3,912	32,153	0.12
South Dakota	1,665	12	4,186	3,801	1.10
Tennessee	350	1	2,263	528	4.29
Texas	342,087	6,878	7,376,913	1,566,371	4.71
Utah	19,520	385	148,579	88,050	1.69
Virginia	19	112	1,562	19,955	0.08
West Virginia	679	225	8,337	40,729	0.20
Wyoming	54,052	2,253	2,355,671	455,086	5.18
State Total	***1,273,759***	***21,290***	***20,258,560***	***5,063,379***	***4.00***
Federal Offshore	467,180	2,787	587,353	963,266	0.61
Tribal Lands	9,513	297	149,261	62,379	2.39
Federal Total	***476,693***	***3,084***	***736,614***	***1,025,645***	***0.72***
U.S. Total	**1,750,452**	**24,374**	**20,995,174**	**6,089,024**	**3.45**

Source: Argonne National Laboratory and Department of Energy (2009). Natural gas production converted to barrels oil equivalent to facilitate comparison using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas. Totals may not sum due to independent rounding.

As can be seen in Table 2-7, the amount of water produced is not necessarily correlated with the ratio of water produced to the volume of oil or natural gas produced. Texas, Alaska and Wyoming were the three largest producers in barrels of oil equivalent (boe) terms, but had relatively low rates of water production compared to more Midwestern states, such Illinois, Missouri, Indiana, and Kansas.

Figure 2-3 shows the distribution of produced water management practices in 2007.

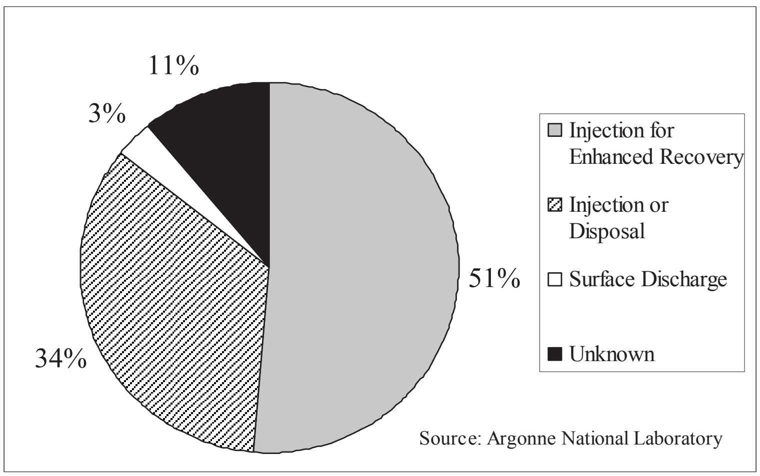

Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

More than half of the water produced (51 percent) was re-injected to enhance resource recovery through maintaining reservoir pressure or hydraulically pushing oil from the reservoir. Another third (34 percent) was injected, typically into wells whose primary purpose is to sequester produced water. A small percentage (three percent) is discharged into surface water when it meets water quality criteria. The destination of the remaining produced water (11 percent, the difference between the total managed and total generated) is uncertain (ANL, 2009).

The movement of crude oil and natural gas primarily takes place via pipelines. Total crude oil pipeline mileage has decreased during the 1990-2008 period (Table 2-8), appearing to follow the downward supply trend shown in Table 2-4. While exhibiting some variation, pipeline mileage transporting refined products remained relatively constant.

Table 2-8 U.S. Oil and Natural Gas Pipeline Mileage, 1990-2008

	Oil Pipelines			Natural Gas Pipelines			
Year	Crude Lines	Product Lines	Total	Distribution Mains	Transmission Pipelines	Gathering Lines	Total
1990	118,805	89,947	208,752	945,964	291,990	32,420	1,270,374
1991	115,860	87,968	203,828	890,876	293,862	32,713	1,217,451
1992	110,651	85,894	196,545	891,984	291,468	32,629	1,216,081
1993	107,246	86,734	193,980	951,750	293,263	32,056	1,277,069
1994	103,277	87,073	190,350	1,002,669	301,545	31,316	1,335,530
1995	97,029	84,883	181,912	1,003,798	296,947	30,931	1,331,676
1996	92,610	84,925	177,535	992,860	292,186	29,617	1,314,663
1997	91,523	88,350	179,873	1,002,942	294,370	34,463	1,331,775
1998	87,663	90,985	178,648	1,040,765	302,714	29,165	1,372,644
1999	86,369	91,094	177,463	1,035,946	296,114	32,276	1,364,336
2000	85,480	91,516	176,996	1,050,802	298,957	27,561	1,377,320
2001	52,386	85,214	154,877	1,101,485	290,456	21,614	1,413,555
2002	52,854	80,551	149,619	1,136,479	303,541	22,559	1,462,579
2003	50,149	75,565	139,901	1,107,559	301,827	22,758	1,432,144
2004	50,749	76,258	142,200	1,156,863	303,216	24,734	1,484,813
2005	46,234	71,310	131,348	1,160,311	300,663	23,399	1,484,373
2006	47,617	81,103	140,861	1,182,884	300,458	20,420	1,503,762
2007	46,658	85,666	147,235	1,202,135	301,171	19,702	1,523,008
2008	50,214	84,914	146,822	1,204,162	303,331	20,318	1,527,811

Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, *Natural Gas Transmission, Gas Distribution, and Hazardous Liquid Pipeline Annual Mileage*, available at http://ops.dot.gov/stats.htm as of Apr. 28, 2010. Totals may not sum due to independent rounding.

Table 2-8 splits natural gas pipelines into three types: distribution mains, transmission pipelines, and gathering lines. Gathering lines are low-volume pipelines that gather natural gas from production sites to deliver directly to gas processing plants or compression stations that connect numerous gathering lines to transport gas primarily to processing plants. Transmission pipelines move large volumes of gas to or from processing plants to distribution points. From these distribution points, the gas enters a distribution system that delivers the gas to final consumers. Table 2-8 shows gathering lines decreasing from 1990 from above 30,000 miles from 1990 to 1995 to around 20,000 miles in 2007 and 2008. Transmission pipelines added about 10,000 miles during this period, from about 292,000 in 1990 to about 303,000 miles in 2008. The most significant growth among all types of pipeline was in distribution, which increased about 260,000 miles during the 1990 to 2008 period, driving an increase in total natural gas pipeline mileage (Figure 2-1). The growth in distribution is likely driven by expanding production as well as expanding gas markets in growing U.S. towns and cities.

2.4.3 Domestic Consumption

Historical crude oil sector-level consumption trends for 1990 through 2009 are shown in Table 2-9 and Figure 2-4. Total consumption rose gradually until 2008 when consumption dropped as a result of the economic recession. The share of residential, commercial, industrial, and electric power on a percentage basis declined during this period, while the share of total consumption by the transportation sector rose from 64 percent in 1990 to 71 percent in 2009.

Table 2-9 Crude Oil Consumption by Sector, 1990-2009

		Percent of Total				
Year	Total (million bbl)	Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	6,201	4.4	2.9	25.3	64.1	3.3
1991	6,101	4.4	2.8	25.2	64.4	3.1
1992	6,234	4.4	2.6	26.5	63.9	2.5
1993	6,291	4.5	2.4	25.7	64.5	2.9
1994	6,467	4.3	2.3	26.3	64.4	2.6
1995	6,469	4.2	2.2	25.9	65.8	1.9
1996	6,701	4.4	2.2	26.3	65.1	2.0
1997	6,796	4.2	2.0	26.6	65.0	2.2
1998	6,905	3.8	1.9	25.6	65.7	3.0
1999	7,125	4.2	1.9	25.8	65.4	2.7
2000	7,211	4.4	2.1	24.9	66.0	2.6
2001	7,172	4.3	2.1	24.9	65.8	2.9
2002	7,213	4.1	1.9	25.0	66.8	2.2
2003	7,312	4.2	2.1	24.5	66.5	2.7
2004	7,588	4.0	2.0	25.2	66.2	2.6
2005	7,593	3.9	1.9	24.5	67.1	2.6
2006	7,551	3.3	1.7	25.1	68.5	1.4
2007	7,548	3.4	1.6	24.4	69.1	1.4
2008	7,136	3.7	1.8	23.2	70.3	1.1
2009*	6,820	3.8	1.8	22.5	71.1	0.9

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary.

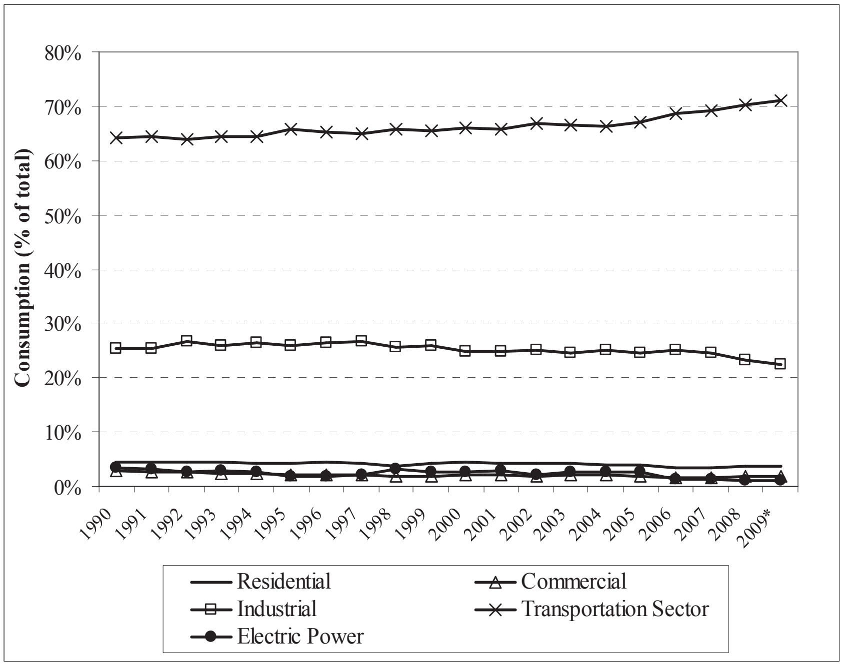

Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2009

Natural gas consumption has increased over the last twenty years. From 1990 to 2009, total U.S. consumption increased by an average of about 1 percent per year (Table 2-10 and Figure 2-5). Over the same period, industrial consumption of natural gas declined, whereas electric power generation increased its consumption quite dramatically, an important trend in the industry as many utilities increasingly use natural gas for peak generation or switch from coal-based to natural gas-based electricity generation. The residential, commercial, and transportation sectors maintained their consumption levels at more or less constant levels during this time period.

Table 2-10 Natural Gas Consumption by Sector, 1990-2009

Year	Total (bcf)	Percent of Total: Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	19,174	22.9	13.7	43.1	3.4	16.9
1991	19,562	23.3	13.9	42.7	3.1	17.0
1992	20,228	23.2	13.9	43.0	2.9	17.0
1993	20,790	23.8	13.8	42.7	3.0	16.7
1994	21,247	22.8	13.6	42.0	3.2	18.4
1995	22,207	21.8	13.6	42.3	3.2	19.1
1996	22,609	23.2	14.0	42.8	3.2	16.8
1997	22,737	21.9	14.1	42.7	3.3	17.9
1998	22,246	20.3	13.5	42.7	2.9	20.6
1999	22,405	21.1	13.6	40.9	2.9	21.5
2000	23,333	21.4	13.6	39.8	2.8	22.3
2001	22,239	21.5	13.6	38.1	2.9	24.0
2002	23,007	21.2	13.7	37.5	3.0	24.7
2003	22,277	22.8	14.3	37.1	2.7	23.1
2004	22,389	21.7	14.0	37.3	2.6	24.4
2005	22,011	21.9	13.6	35.0	2.8	26.7
2006	21,685	20.1	13.1	35.3	2.8	28.7
2007	23,097	20.4	13.0	34.1	2.8	29.6
2008	23,227	21.0	13.5	33.9	2.9	28.7
2009*	22,834	20.8	13.6	32.4	2.9	30.2

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary. Totals may not sum due to independent rounding.

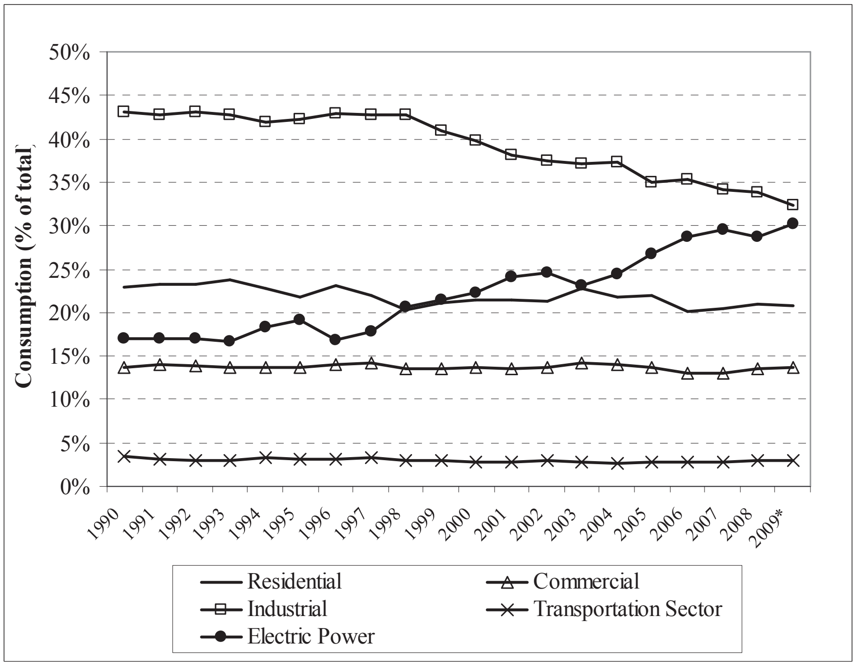

Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2009

2.4.4 International Trade

Imports of crude oil and refined petroleum products have increased over the last twenty years, showing increased substitution of imports for domestic production, as well as imports satisfying growing consumer demand in the U.S (Table 2-11). Crude oil imports have increased by about 2 percent per year on average, whereas petroleum products have increased by 1 percent on average per year.

Table 2-11 Total Crude Oil and Petroleum Products Imports (Million Bbl), 1990-2009

Year	Crude Oil	Petroleum Products	Total Petroleum
1990	2,151	775	2,926
1991	2,111	673	2,784
1992	2,226	661	2,887
1993	2,477	669	3,146
1994	2,578	706	3,284
1995	2,639	586	3,225
1996	2,748	721	3,469
1997	3,002	707	3,709
1998	3,178	731	3,908
1999	3,187	774	3,961
2000	3,320	874	4,194
2001	3,405	928	4,333
2002	3,336	872	4,209
2003	3,528	949	4,477
2004	3,692	1,119	4,811
2005	3,696	1,310	5,006
2006	3,693	1,310	5,003
2007	3,661	1,255	4,916
2008	3,581	1,146	4,727
2009	3,307	973	4,280

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** * 2009 Imports are preliminary.

Natural gas imports also increased steadily from 1990 to 2007 in volume and percentage terms (Table 2-12). The years 2007 and 2008 saw imported natural gas constituting a lower percentage of domestic natural gas consumption. In 2009, the U.S exported 700 bcf natural gas to Canada, 338 bcf to Mexico via pipeline, and 33 bcf to Japan in LNG-form. In 2009, the U.S. primarily imported natural gas from Canada (3268 bcf, 87 percent) via pipeline, although a growing percentage of natural gas imports are in LNG-form shipped from countries such as Trinidad and Tobago and Egypt. Until recent years, industry analysts forecast that LNG imports would continue to grow as a percentage of U.S consumption. However, it is possible that increasingly accessible domestic unconventional gas resources, such as shale gas and coalbed methane, might reduce the need for the U.S. to import natural gas, either via pipeline or shipped LNG.

Table 2-12 Natural Gas Imports and Exports, 1990-2009

Year	Total Imports (bcf)	Total Exports (bcf)	Net Imports (bcf)	Percent of U.S. Consumption
1990	1,532	86	1,447	7.5
1991	1,773	129	1,644	8.4
1992	2,138	216	1,921	9.5
1993	2,350	140	2,210	10.6
1994	2,624	162	2,462	11.6
1995	2,841	154	2,687	12.1
1996	2,937	153	2,784	12.3
1997	2,994	157	2,837	12.5
1998	3,152	159	2,993	13.5
1999	3,586	163	3,422	15.3
2000	3,782	244	3,538	15.2
2001	3,977	373	3,604	16.2
2002	4,015	516	3,499	15.2
2003	3,944	680	3,264	14.7
2004	4,259	854	3,404	15.2
2005	4,341	729	3,612	16.4
2006	4,186	724	3,462	16.0
2007	4,608	822	3,785	16.4
2008	3,984	1,006	2,979	12.8
2009*	3,748	1,071	2,677	11.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 Imports are preliminary.

2.4.5 Forecasts

In this section, we provide forecasts of well drilling activity and crude oil and natural gas domestic production, imports, and prices. The forecasts are from the 2011 Annual Energy Outlook produced by EIA, the most current forecast information available from EIA. As will be discussed in detail in Section 3, to analyze the impacts of the proposed NSPS on the national energy economy, we use the National Energy Modeling System (NEMS) that was used to produce the 2011 Annual Energy Outlook.

Table 2-13 and Figure 2-6 present forecasts of successful wells drilled in the U.S. from 2010 to 2035. Crude oil well forecasts for the lower 48 states show a rise from 2010 to a peak in 2019, which is followed by a gradual decline until the terminal year in the forecast, totaling a 28 percent decline for the forecast period. The forecast of successful offshore crude oil wells shows a variable but generally increasing trend.

Table 2-13 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

	Lower 48 U.S. States					Offshore		Totals	
Year	Crude Oil	Conventional Natural Gas	Tight Sands	Devonian Shale	Coalbed Methane	Crude Oil	Natural gas	Crude Oil	Natural Gas
2010	12,082	7,302	2,393	4,196	2,426	74	56	12,155	16,373
2011	10,271	7,267	2,441	5,007	1,593	81	73	10,352	16,380
2012	10,456	7,228	2,440	5,852	1,438	80	71	10,536	17,028
2013	10,724	7,407	2,650	6,758	1,564	79	68	10,802	18,447
2014	10,844	7,378	2,659	6,831	1,509	85	87	10,929	18,463
2015	10,941	7,607	2,772	7,022	1,609	84	87	11,025	19,096
2016	11,015	7,789	2,817	7,104	1,633	94	89	11,108	19,431
2017	11,160	7,767	2,829	7,089	1,631	104	100	11,264	19,416
2018	11,210	7,862	2,870	7,128	1,658	112	101	11,323	19,619
2019	11,268	8,022	2,943	7,210	1,722	104	103	11,373	20,000
2020	10,845	8,136	3,140	7,415	2,228	89	81	10,934	21,000
2021	10,849	8,545	3,286	7,621	2,324	91	84	10,940	21,860
2022	10,717	8,871	3,384	7,950	2,361	90	77	10,807	22,642
2023	10,680	9,282	3,558	8,117	2,499	92	96	10,772	23,551
2024	10,371	9,838	3,774	8,379	2,626	87	77	10,458	24,694
2025	10,364	10,200	3,952	8,703	2,623	93	84	10,457	25,562
2026	10,313	10,509	4,057	9,020	2,705	104	103	10,417	26,394
2027	10,103	10,821	4,440	9,430	2,862	99	80	10,202	27,633
2028	9,944	10,995	4,424	9,957	3,185	128	111	10,072	28,672
2029	9,766	10,992	4,429	10,138	3,185	121	127	9,887	28,870
2030	9,570	11,161	4,512	10,539	3,240	127	103	9,697	29,556
2031	9,590	11,427	4,672	10,743	3,314	124	109	9,714	30,265
2032	9,456	11,750	4,930	11,015	3,449	143	95	9,599	31,239
2033	9,445	12,075	5,196	11,339	3,656	116	107	9,562	32,372
2034	9,278	12,457	5,347	11,642	3,669	128	92	9,406	33,206
2035	8,743	13,003	5,705	12,062	3,905	109	108	8,852	34,782

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.**

Meanwhile, Table 2-13 and Figure 2-6 show increases for all types of natural gas drilling in the lower 48 states. Drilling in shale reservoirs is expected to rise most dramatically, about 190 percent during the forecast period, while drilling in coalbed methane and tight sands reservoirs increase significantly, 61 percent and 138 percent, respectively. Despite the growth in drilling in unconventional reservoirs, EIA forecasts successful conventional natural gas wells to increase about 78 percent during this period. Offshore natural gas wells are also expected to increase during the next 25 years, but not to the degree of onshore drilling.

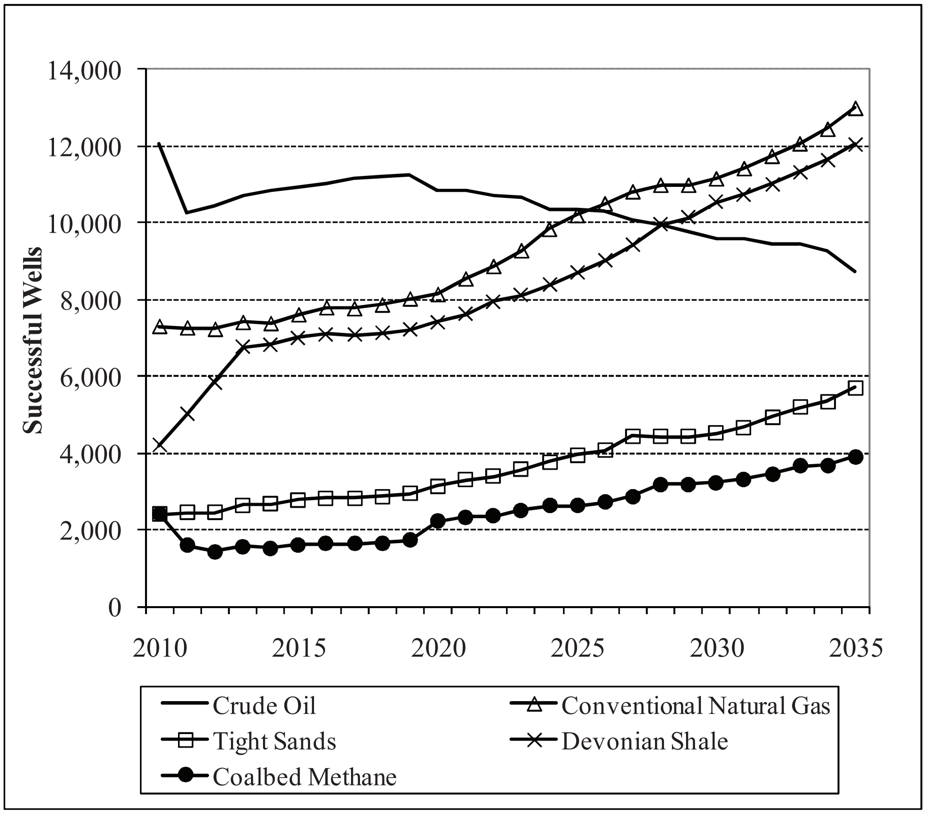

Figure 2-6 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

Table 2-14 presents forecasts of domestic crude oil production, reserves, imports and prices. Domestic crude oil production increases slightly during the forecast period, with much of the growth coming from onshore production in the lower 48 states. Alaskan oil production is forecast to decline from 2010 to a low of 99 million barrels in 2030, but rising above that level for the final five years of the forecast. Net imports of crude oil are forecast to decline slightly during the forecast period. Figure 2-7 depicts these trends graphically. All told, EIA forecasts total crude oil to decrease about 3 percent from 2010 to 2035.

Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2010-2035

	Domestic Production (million bbls)							
Year	Total Domestic	Lower 48 Onshore	Lower 48 Offshore	Alaska	Lower 48 End of Year Reserves	Net Imports	Total Crude Supply (million bbls)	Lower 48 Average Wellhead Price (2009 dollars per bbl)
2010	2,011	1,136	653	223	17,634	3,346	5,361	78.6
2011	1,993	1,212	566	215	17,955	3,331	5,352	84.0
2012	1,962	1,233	529	200	18,026	3,276	5,239	86.2
2013	2,037	1,251	592	194	18,694	3,259	5,296	88.6
2014	2,102	1,267	648	188	19,327	3,199	5,301	92.0
2015	2,122	1,283	660	179	19,690	3,177	5,299	95.0
2016	2,175	1,299	705	171	20,243	3,127	5,302	98.1
2017	2,218	1,320	735	163	20,720	3,075	5,293	101.0
2018	2,228	1,323	750	154	21,129	3,050	5,277	103.7
2019	2,235	1,343	746	147	21,449	3,029	5,264	105.9
2020	2,219	1,358	709	153	21,573	3,031	5,250	107.4
2021	2,216	1,373	680	163	21,730	3,049	5,265	108.8
2022	2,223	1,395	659	169	21,895	3,006	5,229	110.3
2023	2,201	1,418	622	161	21,921	2,994	5,196	112.0
2024	2,170	1,427	588	155	21,871	2,996	5,166	113.6
2025	2,146	1,431	566	149	21,883	3,010	5,155	115.2
2026	2,123	1,425	561	136	21,936	3,024	5,147	116.6
2027	2,114	1,415	573	125	22,032	3,018	5,131	117.8
2028	2,128	1,403	610	116	22,256	2,999	5,127	118.8
2029	2,120	1,399	614	107	22,301	2,988	5,108	119.3
2030	2,122	1,398	625	99	22,308	2,994	5,116	119.5
2031	2,145	1,391	641	114	22,392	2,977	5,122	119.6
2032	2,191	1,380	675	136	22,610	2,939	5,130	118.8
2033	2,208	1,365	691	152	22,637	2,935	5,143	119.1
2034	2,212	1,351	714	147	22,776	2,955	5,167	119.2
2035	2,170	1,330	698	142	22,651	3,007	5,177	119.5

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

Table 2-14 also shows forecasts of proved reserves in the lower 48 states. The reserves forecast shows steady growth from 2010 to 2035, an increase of 28 percent overall. This increment is larger than the forecast increase in production from the lower 48 states during this period, 8 percent, showing reserves are forecast to grow more rapidly than production. Table 2-14 also shows average wellhead prices increasing a total of 52 percent from 2010 to 2035, from $78.6 per barrel to $119.5 per barrel in 2008 dollar terms.

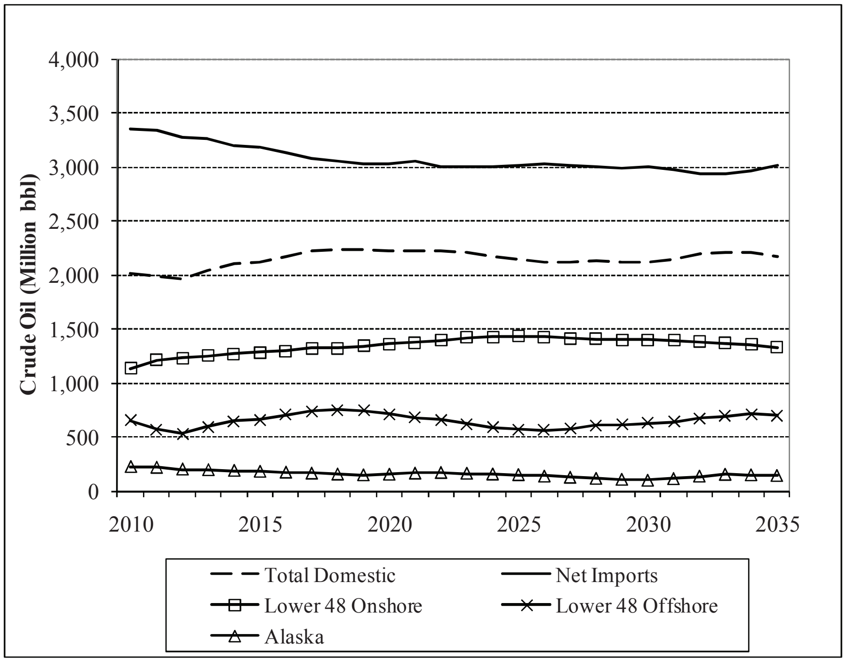

Figure 2-7 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2035

Table 2-15 shows domestic natural gas production is forecast to increase about 24 percent from 2010 to 2035. Contrasted against the much higher growth in natural gas wells drilled as shown in Table 2-13, per well productivity is expected to continue its declining trend. Meanwhile, imports of natural gas via pipeline are expected to decline during the forecast period almost completely, from 2.33 tcf in 2010 to 0.04 in 2035 tcf. Imported LNG also decreases from 0.41 tcf in 2010 to 0.14 tcf in 2035. Total supply, then, increases about 10 percent, from 24.08 tcf in 2010 to 26.57 tcf in 2035.

Table 2-15 Forecast of Natural Gas Supply, Lower 48 Reserves, and Wellhead Price

	Production		Net Imports				
Year	Dry Gas Production	Supplemental Natural Gas	Net Imports (Pipeline)	Net Imports (LNG)	Total Supply	Lower 48 End of Year Dry Reserves	Average Lower 48 Wellhead Price (2009 dollars per Mcf)
2010	21.28	0.07	2.33	0.41	24.08	263.9	4.08
2011	21.05	0.06	2.31	0.44	23.87	266.3	4.09
2012	21.27	0.06	2.17	0.47	23.98	269.1	4.09
2013	21.74	0.06	2.22	0.50	24.52	272.5	4.15
2014	22.03	0.06	2.26	0.45	24.80	276.6	4.16
2015	22.43	0.06	2.32	0.36	25.18	279.4	4.24
2016	22.47	0.06	2.26	0.36	25.16	282.4	4.30
2017	22.66	0.06	2.14	0.41	25.28	286.0	4.33
2018	22.92	0.06	2.00	0.43	25.40	289.2	4.37
2019	23.20	0.06	1.75	0.47	25.48	292.1	4.43
2020	23.43	0.06	1.40	0.50	25.40	293.6	4.59
2021	23.53	0.06	1.08	0.52	25.19	295.1	4.76
2022	23.70	0.06	0.89	0.49	25.14	296.7	4.90
2023	23.85	0.06	0.79	0.45	25.15	297.9	5.08
2024	23.86	0.06	0.77	0.39	25.08	298.4	5.27
2025	23.99	0.06	0.74	0.34	25.12	299.5	5.43
2026	24.06	0.06	0.71	0.27	25.10	300.8	5.54
2027	24.30	0.06	0.69	0.22	25.27	302.1	5.67
2028	24.59	0.06	0.67	0.14	25.47	304.4	5.74
2029	24.85	0.06	0.63	0.14	25.69	306.6	5.78
2030	25.11	0.06	0.63	0.14	25.94	308.5	5.82
2031	25.35	0.06	0.57	0.14	26.13	310.1	5.90
2032	25.57	0.06	0.50	0.14	26.27	311.4	6.01
2033	25.77	0.06	0.38	0.14	26.36	312.6	6.12
2034	26.01	0.06	0.23	0.14	26.44	313.4	6.24
2035	26.33	0.06	0.04	0.14	26.57	314.0	6.42

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

2.5 Industry Costs

2.5.1 Finding Costs

Real costs of drilling oil and natural gas wells have increased significantly over the past two decades, particularly in recent years. Cost per well has increased by an annual average of about 15 percent, and cost per foot has increased on average of about 13 percent per year (Figure 2-8).

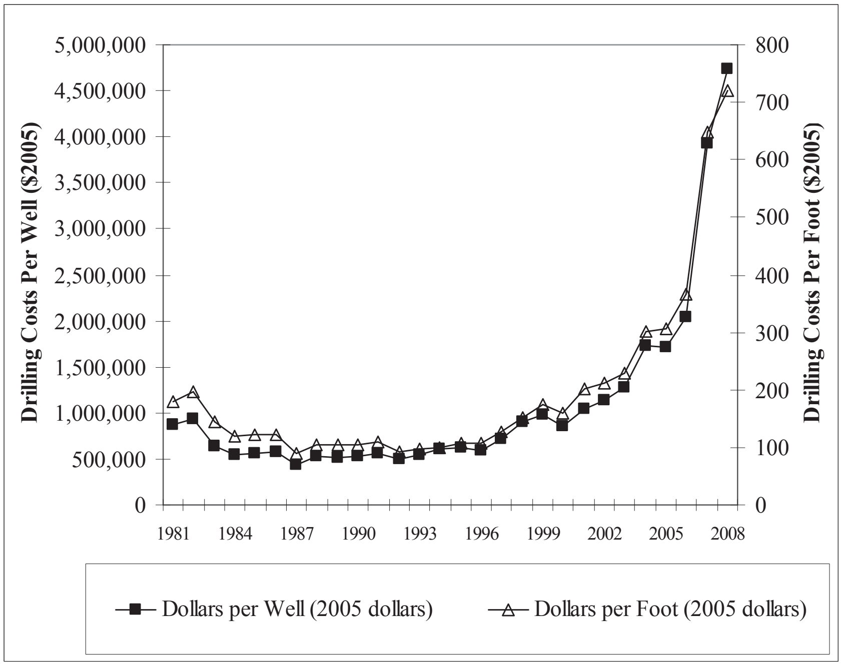

Figure 2-8 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

The average finding costs compiled and published by EIA add an additional level of detail to drilling costs, in that finding costs incorporate the costs more broadly associated with adding proved reserves of crude oil and natural gas. These costs include exploration and development costs, as well as costs associated with the purchase or leasing of real property. EIA publishes finding costs as running three-year averages, in order to better compare these costs, which occur over several years, with annual average lifting costs. Figure 2-9 shows average domestic onshore and offshore and foreign finding costs for the sample of U.S. firms in EIA's Financial Reporting System (FRS) database from 1981 to 2008. The costs are reported in 2008 dollars on a barrel of oil equivalent basis for crude oil and natural gas combined. The average domestic finding costs dropped from 1981 until the mid-1990s. Interestingly, in the mid-1990s, domestic onshore and offshore and foreign finding costs converged for a few years. After this period, offshore finding costs rose faster than domestic onshore and foreign costs.

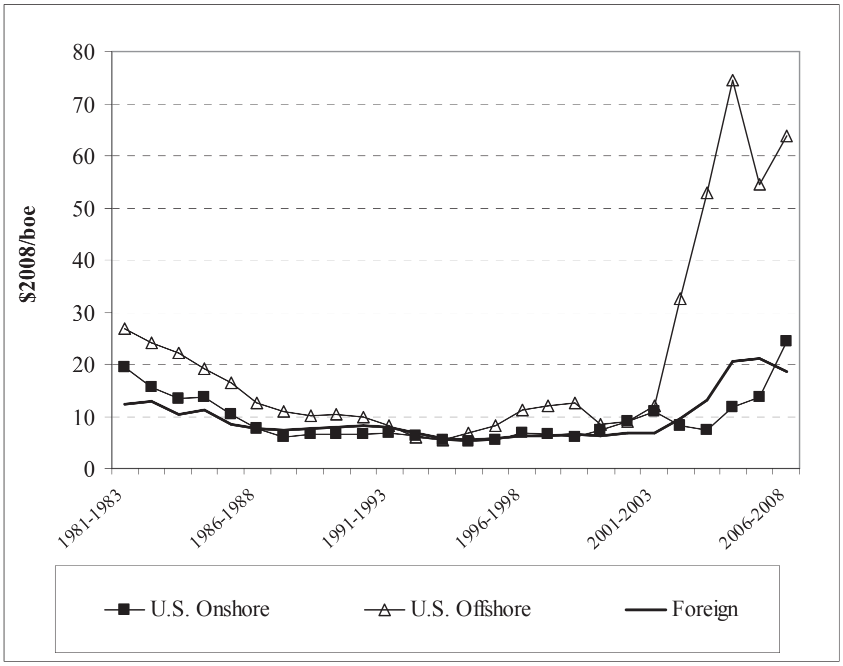

Figure 2-9 Finding Costs for FRS Companies, 1981-2008

After 2000, average finding costs rose sharply, with the finding costs for domestic onshore and offshore and foreign proved reserves diverging onto different trajectories. Note the drilling costs in Figure 2-8 and finding costs in Figure 2-9 present similar trends overall.

2.5.2 Lifting Costs

Lifting costs are the costs to produce crude oil or natural gas once the resource has been found and accessed. EIA's definition of lifting costs includes costs of operating and maintaining wells and associated production equipment. Direct lifting costs exclude production taxes or royalties, while total lifting costs includes taxes and royalties. Like finding costs, EIA reports average lifting costs for FRS firms in 2008 dollars on a barrel of oil equivalent basis. Total lifting costs are the sum of direct lifting costs and production taxes. Figure 2-10 depicts direct lifting cost trends from 1981 to 2008 for domestic and foreign production.

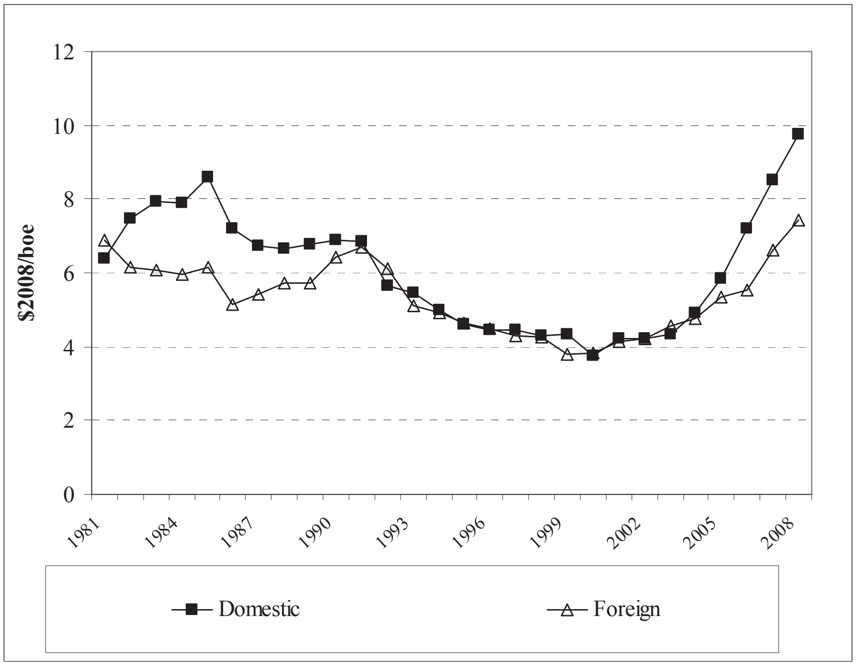

Figure 2-10 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2008 (3-year Running Average)

Direct lifting costs (excludes taxes and royalties) for domestic production rose a little more than $2 per barrels of oil equivalent from 1981 to 1985, then declined almost $5 per barrel of oil equivalent from 1985 until 2000. From 2000 to 2008, domestic lifting costs increased sharply, about $6 per barrel of oil equivalent. Foreign lifting costs diverged from domestic lifting costs from 1981 to 1991, as foreign lifting costs were lower than domestic costs during this period. Foreign and domestic lifting costs followed a similar track until they again diverged in 2004, with domestic lifting again becoming more expensive. Combined with finding costs, the total finding and lifting costs rose significantly in from 2000 to 2008.

2.5.3 Operating and Equipment Costs

The EIA report, "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009"[2], contains indices and estimated costs for domestic oil and natural gas equipment and production operations. The indices and cost trends track costs for representative operations in

[2] U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009." September 28, 2010. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

six regions (California, Mid-Continent, South Louisiana, South Texas, West Texas, and Rocky Mountains) with producing depths ranging from 2000 to 16,000 feet and low to high production rates (for example, 50,000 to 1 million cubic feet per day for natural gas).

Figure 2-11 depicts crude oil operating costs and equipment costs indices for 1976 to 2009, as well as the crude oil price in 1976 dollars. The indices show that crude oil operating and equipment costs track the price of oil over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and oil prices rose steeply in the late 1970s, but generally decreased from about 1980 until the late 1990s.

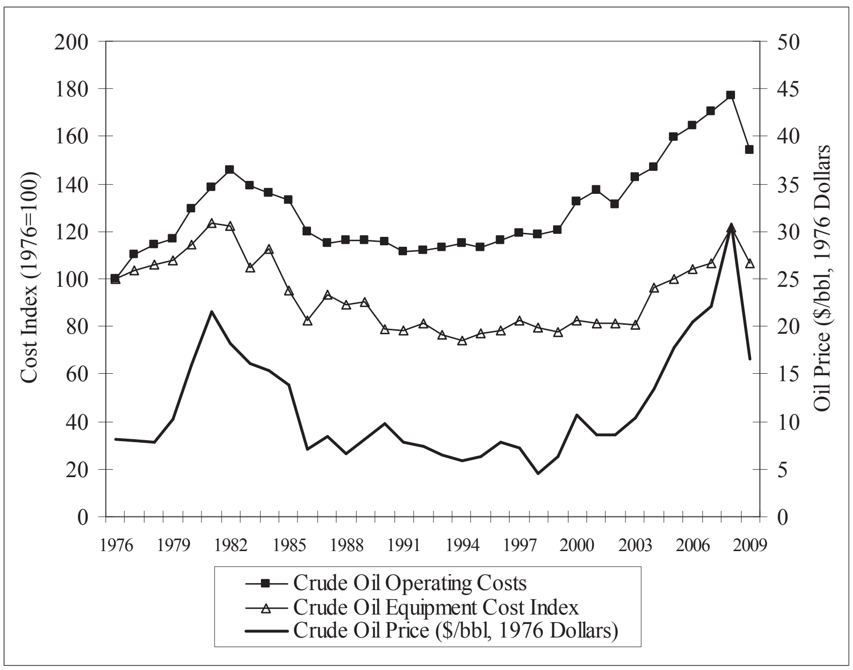

Figure 2-11 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009

Oil costs and prices again generally rose between 2000 to present, with a peak in 2008. The 2009 index values for crude oil operating and equipment costs are 154 and 107, respectively.

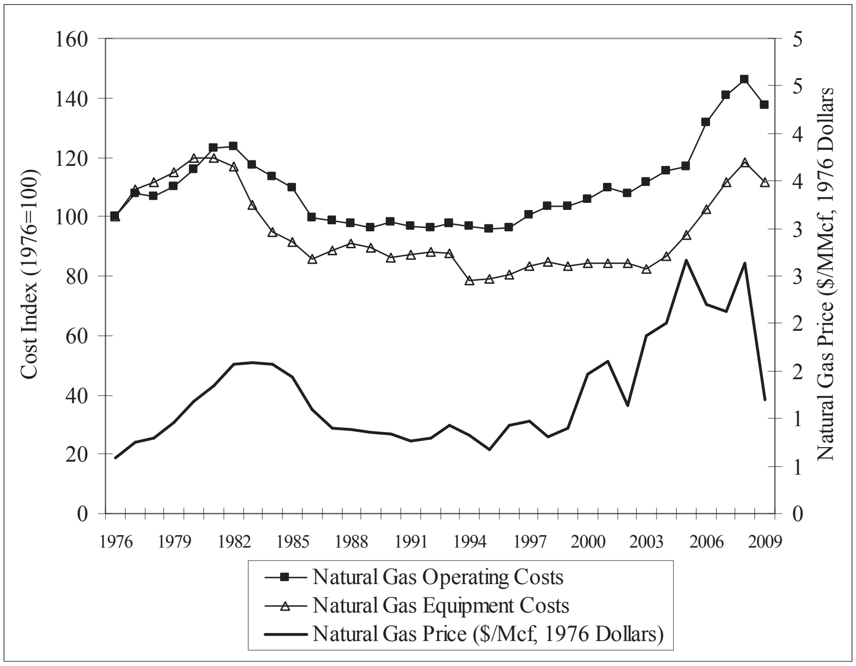

Figure 2-12 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

Figure 2-12 depicts natural gas operating and equipment costs indices, as well as natural gas prices. Similar to the cost trends for crude oil, natural gas operating and equipment costs track the price of natural gas over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and gas prices also rose steeply in the late 1970s, but generally decreased from about 1980 until the mid 1990s. The 2009 index values for natural gas operating and equipment costs are 137 and 112, respectively.

2.6 Firm Characteristics

A regulatory action to reduce pollutant discharges from facilities producing crude oil and natural gas will potentially affect the business entities that own the regulated facilities. In the oil and natural gas production industry, facilities comprise those sites where plant and equipment extract, process, and transport extracted streams recovered from the raw crude oil and natural gas resources. Companies that own these facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility.

2.6.1 Ownership

Enterprises in the oil and natural gas industry may be divided into different groups that include producers, transporters, and distributors. The producer segment may be further divided between major and independent producers. Major producers include large oil and gas companies that are involved in each of the five industry segments: drilling and exploration, production, transportation, refining, and marketing. Independent producers include smaller firms that are involved in some but not all of the five activities.

According to the Independent Petroleum Association of America (IPAA), independent companies produce approximately 68 percent of domestic crude oil production of our oil, 85 percent of domestic natural gas, and drill almost 90 percent of the wells in the U.S (IPAA, 2009). Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. IPAA reports that about 50 percent of its members' spending in 2007 was directed toward natural gas production, largely toward production of unconventional gas (IPAA, 2009). Meanwhile, transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

2.6.2 Size Distribution of Firms in Affected

As of 2007, there were 6,563 firms within the 211111 and 211112 NAICS codes, of which 6427 (98 percent) were considered small businesses (Table 2-16). Within NAICS 211111 and 211112, large firms compose about 2 percent of the firms, but account for 59 percent of employment and generate about 80 percent of estimated receipts listed under the NAICS.

Table 2-16 SBA Size Standards and Size Distribution of Oil and Natural Gas Firms

NAICS	NAICS Description	SBA Size Standard	Small Firms	Large Firms	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	98	41	139
213111	Drilling Oil and Gas Wells	500	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	61*	65*	126
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	24,683
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	500	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	20,796,681

Note: *The counts of small and large firms in NAICS 486210 is based upon firms with less than $7.5 million in receipts, rather than the $7 million required by the SBA Size Standard. We used this value because U.S. Census reports firm counts for firms with receipts less than $7.5 million. **Employment and receipts could not be split between small and large businesses because of non-disclosure requirements faced by the U.S. Census Bureau. Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007." <http://www.census.gov/econ/susb/>

The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 66 percent and 69 percent of employment and estimated receipts, respectively. Because there are relatively few firms within NAICS 486210, the Census Bureau cannot release breakdowns of firms by size in sufficient detail to perform similar calculation.

2.6.3 *Trends in National Employment and Wages*

As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in oil and natural gas-related NAICS codes from 1990 to 2009. The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of 313,703 in 1999, but rebounding to a 2008 peak of 511,805. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry.

Table 2-17 Oil and Natural Gas Industry Employment by NAICS, 1990-09

Year	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Ops. (213112)	Pipeline Trans. of Crude Oil (486110)	Pipeline Trans. of Natural Gas (486210)	Total
1990	182,848	8,260	52,365	109,497	11,112	47,533	411,615
1991	177,803	8,443	46,466	116,170	11,822	48,643	409,347
1992	169,615	8,819	39,900	99,924	11,656	46,226	376,140
1993	159,219	7,799	42,485	102,840	11,264	43,351	366,958
1994	150,598	7,373	44,014	105,304	10,342	41,931	359,562
1995	142,971	6,845	43,114	104,178	9,703	40,486	347,297
1996	139,016	6,654	46,150	107,889	9,231	37,519	346,459
1997	137,667	6,644	55,248	117,460	9,097	35,698	361,814
1998	133,137	6,379	53,943	122,942	8,494	33,861	358,756
1999	124,296	5,474	41,868	101,694	7,761	32,610	313,703
2000	117,175	5,091	52,207	108,087	7,657	32,374	322,591
2001	119,099	4,500	62,012	123,420	7,818	33,620	30,469
2002	116,559	4,565	48,596	120,536	7,447	31,556	329,259
2003	115,636	4,691	51,526	120,992	7,278	29,684	329,807
2004	117,060	4,285	57,332	128,185	7,073	27,340	341,275
2005	121,535	4,283	66,691	145,725	6,945	27,341	372,520
2006	130,188	4,670	79,818	171,127	7,202	27,685	420,690
2007	141,239	4,842	84,525	197,100	7,975	27,431	463,112
2008	154,898	5,183	92,640	223,635	8,369	27,080	511,805
2009	155,150	5,538	67,756	193,589	8,753	26,753	457,539

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

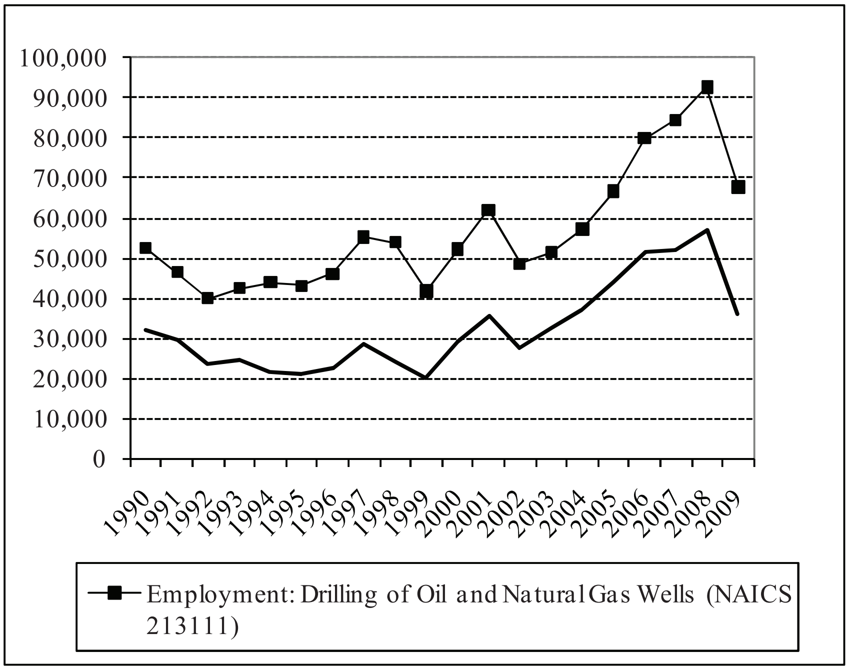

Figure 2-13 Employment in Drilling of Oil and Natural Gas Wells (NAICS 213111), and Total Oil and Natural Gas Wells Drilled, 1990-2009

Figure 2-13 compares employment in Drilling of Oil and Natural Gas Wells (NAICS 213111) with the total number of oil and natural gas wells drilled from 1990 to 2009. The figure depicts a strong positive correlation between employment in the sector with drilling activity. This correlation also holds throughout the period covered by the data.

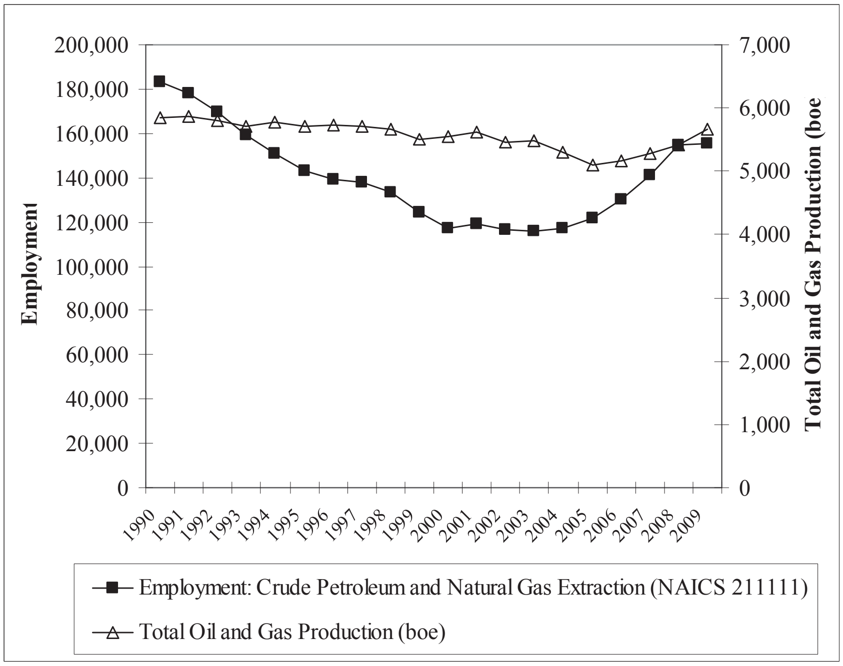

Figure 2-14 Employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Total Crude Oil and Natural Gas Production (boe), 1990-2009

Figure 2-14 compares employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) with total domestic oil and natural gas production from 1990 to 2009 in barrels of oil equivalent terms. While until 2003, employment in this sector and total production declined gradually, employment levels declined more rapidly. However, from 2004 to 2009 employment in Extraction recovered, rising to levels similar to the early 1990s.

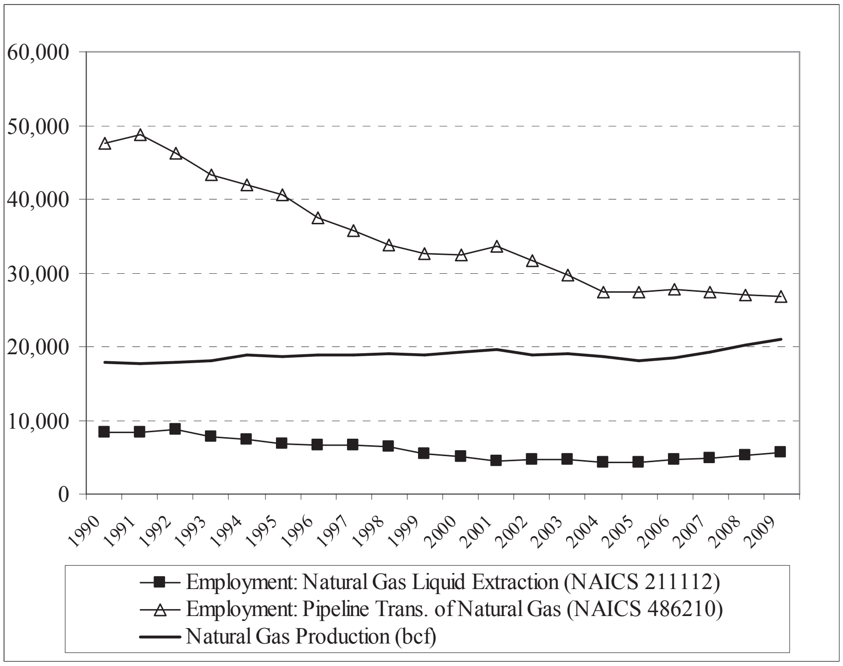

Figure 2-15 Employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009

Figure 2-15 depicts employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009. While total natural gas production has risen slightly over this time period, employment in natural gas pipeline transportation has steadily declined to almost half of its 1991 peak. Employment in natural gas liquid extraction declined from 1992 to a low in 2005, then rebounded slightly from 2006 to 2009. Overall, however, these trends depict these sectors becoming decreasingly labor intensive, unlike the trends depicted in Figure 2-13 and Figure 2-14.

From 1990 to 2009, average wages for the oil and natural gas industry have increased. Table 2-18 and Figure 2-16 show real wages (in 2008 dollars) from 1990 to 2009 for the NAICS codes associated with the oil and natural gas industry.

Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 (2008 dollars)

Year	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Operations (213112)	Pipeline Transportation of Crude Oil (486110)	Pipeline Transportation of Natural Gas (486210)	Total
1990	71,143	66,751	42,215	45,862	68,044	61,568	59,460
1991	72,430	66,722	43,462	47,261	68,900	65,040	60,901
1992	76,406	68,846	43,510	48,912	74,233	67,120	64,226
1993	77,479	68,915	45,302	50,228	72,929	67,522	64,618
1994	79,176	70,875	44,577	50,158	76,136	68,516	64,941
1995	81,433	67,628	46,243	50,854	78,930	71,965	66,446
1996	84,211	68,896	48,872	52,824	76,841	76,378	68,391
1997	89,876	79,450	52,180	55,600	78,435	82,775	71,813
1998	93,227	89,948	53,051	57,578	79,089	84,176	73,722
1999	98,395	89,451	54,533	59,814	82,564	94,471	79,078
2000	109,744	112,091	60,862	60,594	81,097	130,630	86,818
2001	111,101	111,192	61,833	61,362	83,374	122,386	85,333
2002	109,957	103,653	62,196	59,927	87,500	91,550	82,233
2003	110,593	112,650	61,022	61,282	87,388	91,502	82,557
2004	121,117	118,311	63,021	62,471	93,585	93,684	86,526
2005	127,243	127,716	70,772	67,225	92,074	90,279	90,292
2006	138,150	133,433	74,023	70,266	91,708	98,691	94,925
2007	135,510	132,731	82,010	71,979	96,020	105,441	96,216
2008	144,542	125,126	81,961	74,021	101,772	99,215	99,106
2009	133,575	123,922	80,902	70,277	100,063	100,449	96,298

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

Employees in the NAICS 211 codes enjoy the highest average wages in the industry, while employees in the NAICS 213111 code have relatively lower wages. Average wages in natural gas pipeline transportation show the highest variation, with a rapid climb from 1990 to 2000, more than doubling in real terms. However, since 2000 wages have declined in the pipeline transportation sector, while wages have risen in the other NAICS.

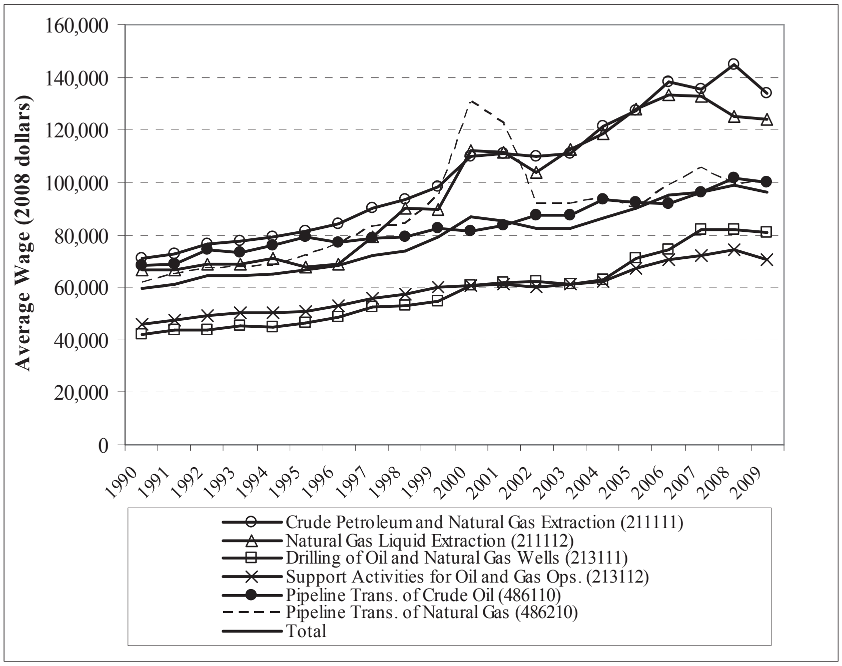

Figure 2-16 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 ($2008)

2.6.4 Horizontal and Vertical Integration

Because of the existence of major companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one. Vertical integration is a potentially important dimension in analyzing firm-level impacts because the regulation could affect a vertically integrated firm on more than one level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company that owns oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosene. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons. A horizontally integrated firm may own many facilities of which only some are directly affected by the regulation. Additionally, a horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation. A horizontally integrated firm could also be indirectly as well as directly affected by the regulation.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of regulation of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is less predominant than in the oil sector. Transmission and local distribution of natural gas usually occur at individual firms, although processing is increasing performed by the integrated major companies. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms only. Typically wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independents have to rely only on profits generated at the wellhead from the sale of oil and natural gas or the provision of oil and gas production-related engineering or financial services. Overall, independent producers typically sell their output to refineries or natural gas pipeline companies and are not vertically integrated. Independents may also own relatively few facilities, indicating limited horizontal integration.

2.6.5 Firm-level Information

The annual *Oil and Gas Journal* (OGJ) survey, the OGJ150, reports financial and operating results for top 150 public oil and natural gas companies with domestic reserves and headquarters in the U.S. In the past, the survey reported information on the top 300 companies, now the top 150. In 2010, only 137 companies are listed[3]. Table 2-19 lists selected statistics for

[3] Oil and Gas Journal. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.

the top 20 companies in 2010. The results presented in the table reflect relatively lower production and financial figures as a result of the economic recession of this period.

Total earnings for the top 137 companies fell from 2008 to 2009 from $71 billion to $27 billion, reflecting the weak economy. Revenues for these companies also fell 35 percent during this period. 69 percent of the firms posted net losses in 2009, compared to 46 percent one year earlier (*Oil and Gas Journal*, September 6, 2010).

The total worldwide liquids production for the 137 firms declined 0.5 percent to 2.8 billion bbl, while total worldwide gas production increased about 3 percent to a total of 16.5 tcf (*Oil and Gas Journal*, September 6, 2010). Meanwhile, the 137 firms on the OGJ list increased both oil and natural gas production and reserves from 2008 to 2009. Domestic production of liquids increased about 7 percent to 1.1 billion bbl, and natural gas production increased to 10.1 tcf. For context, the OGJ150 domestic crude production represents about 57 percent of total domestic production (1.9 billion bbl, according to EIA). The OGJ150 natural gas production represents about 54 percent of total domestic production (18.8 tcf, according to EIA).

The OGJ also releases a period report entitled "Worldwide Gas Processing Survey", which provides a wide range of information on existing processing facilities. We used a recent list of U.S. gas processing facilities (*Oil and Gas Journal*, June 7, 2010) and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. As of 2009, there are 579 gas processing facilities in the U.S., with a processing capacity of 73,767 million cubic feet per day and throughout of 45,472 million cubic feet per day (Table 2-20). The overall trend in U.S. gas processing capacity is showing fewer, but larger facilities. For example, in 1995, there were 727 facilities with a capacity of 60,533 million cubic feet per day (U.S. DOE, 2006).

Trends in gas processing facility ownership are also showing a degree of concentration, as large firms own multiple facilities, which also tend to be relatively large facilities (Table 2-20). While we estimate 142 companies own the 579 facilities, the top 20 companies (in terms of total throughput) own 264 or 46 percent of the facilities. That larger companies tend to own larger facilities is indicated by these top 20 firms owning 86 percent of the total capacity and 88 percent of actual throughput.

Table 2-19 Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2010

Rank by Total Assets	Company	Employees	Total Assets ($ millions)	Total Rev. ($ millions)	Net Inc. ($ millions)	Worldwide Production		U.S. Production		Net Wells Drilled
						Liquids (Million bbl)	Natural Gas (Bcf)	Liquids (Million bbl)	Natural Gas (Bcf)	
1	ExxonMobil Corp.	102,700	233,323	310,586	19,280	725	2,383	112	566	466
2	Chevron Corp.	64,000	164,621	171,636	10,563	674	1,821	177	511	594
3	ConocoPhillips	30,000	152,588	152,840	4,858	341	1,906	153	850	692
4	Anadarko Petroleum Corp.	4,300	50,123	9,000	-103	88	817	63	817	630
5	Marathon Oil Corp.	28,855	47,052	54,139	1,463	90	351	23	146	115
6	Occidental Petroleum Corp.	10,100	44,229	15,531	2,915	179	338	99	232	260
7	XTO Energy Inc.	3,129	36,255	9,064	2,019	32	855	32	855	1,059
8	Chesapeake Energy Corp.	8,200	29,914	7,702	-5,805	12	835	12	835	1,003
9	Devon Energy Corp.	5,400	29,686	8,015	-2,479	72	966	43	743	521
10	Hess Corp.	13,300	29,465	29,569	740	107	270	26	39	48
11	Apache Corp.	3,452	28,186	8,615	-284	106	642	35	243	124
12	El Paso Corp.	4,991	22,505	4,631	-539	6	219	6	215	134
13	EOG Resources Inc.	2,100	18,119	14,787	547	29	617	26	422	652
14	Murphy Oil Corp.	8,369	12,756	18,918	838	48	68	6	20	3
15	Noble Energy Inc.	1,630	11,807	2,313	-131	29	285	17	145	540
16	Williams Cos. Inc.	4,801	9,682	2,219	400	0	3,435	0	3,435	488
17	Questar Corp.	2,468	8,898	3,054	393	4	169	4	169	194
18	Pioneer Nat. Resources Co.	1,888	8,867	1,712	-52	19	157	17	148	67
19	Plains Expl. & Prod. Co.	808	7,735	1,187	136	18	78	18	78	53
20	Petrohawk Energy Corp.	469	6,662	41,084	-1,025	2	174	2	174	162

Source: *Oil and Gas Journal*. “OGJ150 Financial Results Down in '09; Production, Reserves Up.” September 6, 2010.

Notes: The source for employment figures is the American Business Directory.

Table 2-20 Top 20 Natural Gas Processing Firms (Based on Throughput), 2009

Rank	Company	Processing Plants (No.)	Natural Gas Capacity (MMcf/day)	Natural Gas Throughput (MMcf/day)
1	BP PLC	19	13,378	11,420
2	DCP Midstream Inc.	64	9,292	5,586
3	Enterprise Products Operating LP—	23	10,883	5,347
4	Targa Resources	16	4,501	2,565
5	Enbridge Energy Partners LP—	19	3,646	2,444
6	Williams Cos.	10	4,826	2,347
7	Martin Midstream Partners	16	3,384	2,092
8	Chevron Corp.	23	1,492	1,041
9	Devon Gas Services LP	6	1,038	846
10	ExxonMobil Corp.	6	1,238	766
11	Occidental Petroleum Corp	7	776	750
12	Kinder Morgan Energy Partners	9	1,318	743
13	Enogex Products Corp.	8	863	666
14	Hess Corp.	3	1,060	613
15	Norcen Explorer	1	600	500
16	Copano Energy	1	700	495
17	Anadarko	18	816	489
18	Oneok Field Services	10	1,751	472
19	Shell	4	801	446
20	DTE Energy	1	800	400
	TOTAL FOR TOP 20	264	63,163	40,028
	TOTAL FOR ALL COMPANIES	579	73,767	45,472

Source: *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants.

The OGJ also issues a periodic report on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies, which amounts to 136 companies in 2010 (*Oil and Gas Journal*, November 1, 2010). Table 2-21 presents the pipeline mileage, volumes of natural gas transported, operating revenue, and net income for the top 20 U.S. natural gas pipeline companies in 2009. Ownership of gas pipelines is mostly independent from ownership of oil and gas production companies, as is seen from the lack of overlap between the OGJ list of pipeline companies and the OGJ150. This observation shows that the pipeline industry is still largely based upon firms serving regional market.

The top 20 companies maintain about 63 percent of the total pipeline mileage and transport about 54 percent of the volume of the industry (Table 2-21). Operating revenues of the top 20 companies equaled $11.5 billion, representing 60 percent of the total operating revenues for major and non-major companies. The top 20 companies also account for 64 percent of the net income of the industry.

Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2009

Rank	Company	Transmission (miles)	Vol. trans for others (MMcf)	Op. Rev. (thousand $)	Net Income
1	Natural Gas Pipeline Co of America	9,312	1,966,774	1,131,548	348,177
2	Dominion Transmission Inc.	3,452	609,193	831,773	212,365
3	Columbia Gas Transmission LLC	9,794	1,249,188	796,437	200,447
4	Panhandle Eastern Pipe Line Co. LP	5,894	675,616	377,563	196,825
5	Transcontinental Gas Pipe Line Co. LLC	9,362	2,453,295	1,158,665	192,830
6	Texas Eastern Transmission LP	9,314	1,667,593	870,812	179,781
7	Northern Natural Gas Co.	15,028	922,745	690,863	171,427
8	Florida Gas Transmission Co. LLC	4,852	821,297	520,641	164,792
9	Tennessee Gas Pipeline Co.	14,113	1,704,976	820,273	147,378
10	Southern Natural Gas Co.	7,563	867,901	510,500	137,460
11	El Paso Natural Gas Co.	10,235	1,493,213	592,503	126,000
12	Gas Transmission Northwest Corp.	1,356	809,206	216,526	122,850
13	Rockies Express Pipeline LLC	1,682	721,840	555,288	117,243
14	CenterPoint Energy Gas Transmission Co.	6,162	1,292,931	513,315	116,979
15	Colorado Interstate Gas Co.	4,200	839,184	384,517	108,483
16	Kern River Gas Transmission Co.	1,680	789,858	371,951	103,430
17	Trunkline LNG Co. LLC	—	—	134,150	101,920
18	Northwest Pipeline GP	3,895	817,832	434,379	99,340
19	Texas Gas Transmission LLC	5,881	1,006,906	361,406	91,575
20	Algonquin Gas Transmission LLC	1,128	388,366	237,291	82,472
	TOTAL FOR TOP 20	124,903	21,097,914	11,510,401	3,021,774
	TOTAL FOR ALL COMPANIES	198,381	38,793,532	18,934,674	4,724,456

Source: *Oil and Gas Journal*. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

2.6.6 Financial Performance and Condition

From a broad industry perspective, the EIA Financial Reporting System (FRS) collects financial and operating information from a subset of the U.S. major energy producing companies. This information is used in annual report to Congress, as well as is released to the public in aggregate form. While the companies that report information to FRS each year changes, EIA makes an effort to retain sufficient consistency such that trends can be evaluated.

For 2008, there are 27 companies in the FRS[4] that accounted for 41 percent of total U.S. crude oil and NGL production, 43 percent of natural gas production, 77 percent of U.S. refining capacity, and 0.2 percent of U.S. electricity net generation (U.S. EIA, 2010). Table 2-22 shows a series of financial trends in 2008 dollars selected and aggregated from FRS firms' financial statements. The table shows operating revenues and expenses rising significantly from 1990 to 2008, with operating income (the difference between operating revenues and expenses) rising as well. Interest expenses remained relatively flat during this period. Meanwhile, recent years have shown that other income and income taxes have played a more significant role for the industry. Net income has risen as well, although 2008 saw a decline from previous periods, as oil and natural gas prices declined significantly during the latter half of 2008.

Table 2-22 Selected Financial Items from Income Statements (Billion 2008 Dollars)

Year	Operating Revenues	Operating Expenses	Operating Income	Interest Expense	Other Income*	Income Taxes	Net Income
1990	766.9	706.4	60.5	16.8	13.6	24.8	32.5
1991	673.4	635.7	37.7	14.4	13.4	15.4	21.3
1992	670.2	637.2	33.0	12.7	-5.6	12.2	2.5
1993	621.4	586.6	34.8	11.0	10.3	12.7	21.5
1994	606.5	565.6	40.9	10.8	6.8	14.4	22.5
1995	640.8	597.5	43.3	11.1	12.9	17.0	28.1
1996	706.8	643.3	63.6	9.1	13.4	26.1	41.8
1997	673.6	613.8	59.9	8.2	13.4	23.9	41.2
1998	614.2	594.1	20.1	9.2	11.0	6.0	15.9
1999	722.9	682.6	40.3	10.9	12.7	13.6	28.6
2000	1,114.3	1,011.8	102.5	12.9	18.4	42.9	65.1
2001	961.8	880.3	81.5	10.8	7.6	33.1	45.2
2002	823.0	776.9	46.2	12.7	7.9	17.2	24.3
2003	966.9	872.9	94.0	10.1	19.5	37.2	66.2
2004	1,188.5	1,051.1	137.4	12.4	20.1	54.2	90.9
2005	1,447.3	1,263.8	183.5	11.6	34.6	77.1	129.3
2006	1,459.0	1,255.0	204.0	12.4	41.2	94.8	138.0
2007	1,475.0	1,297.7	177.3	11.1	47.5	86.3	127.4
2008	1,818.1	1,654.0	164.1	11.4	32.6	98.5	86.9

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). * Other Income includes other revenue and expense (excluding interest expense), discontinued operations, extraordinary items, and accounting changes. Totals may not sum due to independent rounding.

[4] Alenco, Anadarko Petroleum Corporation, Apache Corporation, BP America, Inc., Chesapeake Energy Corporation, Chevron Corporation, CITGO Petroleum Corporation, ConocoPhillips, Devon Energy Corporation, El Paso Corporation, EOG Resources, Inc., Equitable Resources, Inc., Exxon Mobil Corporation, Hess Corporation, Hovensa, Lyondell Chemical Corporation, Marathon Oil Corporation, Motiva Enterprises, L.L.C., Occidental Petroleum Corporation, Shell Oil Company, Sunoco, Inc., Tesoro Petroleum Corporation, The Williams Companies, Inc., Total Holdings USA, Inc., Valero Energy Corp., WRB Refining LLC, and XTO Energy, Inc.

Table 2-23 shows in percentage terms the estimated return on investments for a variety of business lines, in 1998, 2003, and 2008, for FRS companies. For U.S. petroleum-related business activities, oil and natural gas production has remained the most profitable line of business relative to refining/marketing and pipelines, sustaining a return on investment greater than 10 percent for the three years evaluated. Returns to foreign oil and natural gas production rose above domestic production in 2008. Electric power generation and sales emerged in 2008 as a highly profitable line of business for the FRS companies.

Table 2-23 Return on Investment for Lines of Business (all FRS), for 1998, 2003, and 2008 (percent)

Line of Business	1998	2003	2008
Petroleum	10.8	13.4	12.0
U.S. Petroleum	10	13.7	8.2
Oil and Natural Gas Production	12.5	16.5	10.7
Refining/Marketing	6.6	9.3	2.6
Pipelines	6.7	11.5	2.4
Foreign Petroleum	11.9	13.0	17.8
Oil and Natural Gas Production	12.5	14.2	16.3
Refining/Marketing	10.6	8.0	26.3
Downstream Natural Gas*	-	8.8	5.1
Electric Power*	-	5.2	181.4
Other Energy	7.1	2.8	-2.1
Non-energy	10.9	2.4	-5.3

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). Note: Return on investment measured as contribution to net income/net investment in place. * The downstream natural gas and electric power lines of business were added to the EIA-28 survey form beginning with the 2003 reporting year.

The oil and natural gas industry also produces significant tax revenues for local, state, and federal authorities. Table 2-24 shows income and production tax trends from 1990 to 2008 for FRS companies. The column with U.S. federal, state, and local taxes paid or accrued includes deductions for the U.S. Federal Investment Tax Credit ($198 million in 2008) and the effect of the Alternative Minimum Tax ($34 million in 2008). Income taxes paid to state and local authorizes were $3,060 million in 2008, about 13 percent of the total paid to U.S. authorities.

Table 2-24 Income and Production Taxes, 1990-2008 (Million 2008 Dollars)

Year	U.S. Federal, State, and Local Taxes Paid or Accrued	Total Current	Total Deferred	Total Income Tax Expense	Other Non-Income Production Taxes Paid
1990	9,568	25,056	-230	24,826	4,341
1991	6,672	18,437	-3,027	15,410	3,467
1992	4,994	16,345	-4,116	12,229	3,097
1993	3,901	13,983	-1,302	12,681	2,910
1994	3,348	13,556	887	14,443	2,513
1995	6,817	17,474	-510	16,965	2,476
1996	8,376	22,493	3,626	26,119	2,922
1997	7,643	20,764	3,141	23,904	2,743
1998	1,199	7,375	-1,401	5,974	1,552
1999	2,626	13,410	140	13,550	2,147
2000	14,308	36,187	6,674	42,861	3,254
2001	10,773	28,745	4,351	33,097	3,042
2002	814	17,108	46	17,154	2,617
2003	9,274	30,349	6,879	37,228	3,636
2004	19,661	50,185	4,024	54,209	3,990
2005	29,993	72,595	4,529	77,125	5,331
2006	29,469	85,607	9,226	94,834	5,932
2007	28,332	84,119	2,188	86,306	7,501
2008	23,199	95,590	2,866	98,456	12,507

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The difference between total current taxes and U.S. federal, state, and local taxes in includes taxes and royalties paid to foreign countries. As can be seen in Table 2-24, foreign taxes paid far exceeds domestic taxes paid. Other non-income production taxes paid, which have risen almost three-fold between 1990 and 2008, include windfall profit and severance taxes, as well as other production-related taxes.

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3 EMISSIONS AND ENGINEERING COSTS

3.1 Introduction

This section includes three sets of discussions for both the proposed NSPS and NESHAP amendments:

- Emission Sources and Points
- Emissions Control Options
- Engineering Cost Analysis

3.2 Emissions Points, Controls, and Engineering Costs Analysis

This section discusses the emissions points and pollution control options for the proposed NSPS and NESHAP amendments. This discussion of emissions points and control options is meant to assist the reader of the RIA in better understanding the economic impact analysis. However, we provide reference to the detailed technical memoranda prepared by the Office of Air Quality Planning and Standards (OAQPS) for the reader interested in a greater level of detail. This section also presents the engineering cost analysis, which provides a cost basis for the energy system, welfare, employment, and small business analyses.

Before going into detail on emissions points and pollution controls, it is useful to provide estimates of overall emissions from the crude oil and natural industry to provide context for estimated reductions as a result of the regulatory options evaluated. To estimate VOC emissions from the oil and gas sector, we modified the emissions estimate for the crude oil and natural gas sector in the 2008 National Emissions Inventory (NEI). During this review, EPA identified VOC emissions from natural gas sources which are likely relatively under-represented in the NEI, natural gas well completions primarily. Crude oil and natural gas sector VOC emissions estimated in the 2008 NEI total approximately 1.76 million tons. Of these emissions, the NEI identifies about 21 thousand tons emitted from natural gas well completion processes. We substituted the estimates of VOC emissions from natural gas well completions estimated as part of the engineering analysis (510,000 tons, which is discussed in more detail in the next section), bringing the total estimated VOC emissions from the crude oil and natural gas sector to about 2.24 million tons VOC.

The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 ($MMtCO_2$-e). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 $MMtCO_2$-e to approximately 330 $MMtCO_2$-e.

3.2.1 Emission Points and Pollution Controls assessed in the RIA

3.2.1.1 NSPS Emission Points and Pollution Controls

A series of emissions controls were evaluated as part of the NSPS review. This section provides a basic description of possible emissions sources and the controls evaluated for each source to facilitate the reader's understanding of the economic impact and benefit analyses. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant chapters within the Technical Support Document (TSD) which is published in the Docket. The chapters are also referenced below. EPA is soliciting public comment and data relevant to several emissions-related issues related to the proposed NSPS. The comments we receive during the public comment period will help inform the rule development process as we work toward promulgating a final action.

Centrifugal and reciprocating compressors (TSD Chapter 6)**:** There are many locations throughout the oil and gas sector where compression of natural gas is required to move the gas along the pipeline. This is accomplished by compressors powered by combustion turbines, reciprocating internal combustion engines, or electric motors. Turbine-powered compressors use a small portion of the natural gas that they compress to fuel the turbine. The turbine operates a centrifugal compressor, which compresses and pumps the natural gas through the pipeline. Sometimes an electric motor is used to turn a centrifugal compressor. This type of compression does not require the use of any of the natural gas from the pipeline, but it does require a source of electricity. Reciprocating spark ignition engines are also used to power many compressors, referred to as reciprocating compressors, since they compress gas using pistons that are driven by the engine. Like combustion turbines, these engines are fueled by natural gas from the pipeline.

Both centrifugal and reciprocating compressors are sources of VOC emissions, and EPA evaluated compressors for coverage under the NSPS. Centrifugal compressors require seals around the rotating shaft to prevent gases from escaping where the shaft exits the compressor casing. The seals in some compressors use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated, and the gas is commonly vented to the atmosphere. These are commonly called "wet" seals. An alternative to a wet seal system is the mechanical dry seal system. This seal system does not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and static pressure. Fugitive VOC is emitted from dry seals around the compressor shaft. The use of dry gas seals substantially reduces emissions. In addition, they significantly reduce operating costs and enhance compressor efficiency.

Reciprocating compressors in the natural gas industry leak natural gas during normal operation. The highest volume of gas loss is associated with piston rod packing systems. Packing systems are used to maintain a tight seal around the piston rod, preventing the gas compressed to high pressure in the compressor cylinder from leaking, while allowing the rod to move freely. Monitoring and replacing compressor rod packing systems on a regular basis can greatly reduce VOC emissions.

Equipment leaks (TSD Chapter 8)**:** Equipment leaks are fugitive emissions emanating from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines, and other process and operation components. There are several potential reasons for equipment leak emissions. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. Because of the large number of valves, pumps, and other components within an oil and gas production, processing, and transmission facility, equipment leaks of volatile emissions from these components can be significant. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components. These types of equipment also exist at production sites and gas transmission/compressor stations. While the number of components at individual transmission/compressor stations is relatively smaller than at processing plants, collectively there are many components that can result in significant emissions. Therefore, EPA evaluated NSPS for equipment leaks for facilities in the production segment of the industry, which includes everything from the wellhead to the point that the gas enters the processing plant or refinery.

Pneumatic controllers (TSD Chapter 5): Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature. Pneumatic controllers are widely used in the oil and natural gas sector. In many situations, the pneumatic controllers used in the oil and gas sector make use of the available high-pressure natural gas to regulate temperature, pressure, liquid level, and flow rate across all areas of the industry. In these "gas-driven" pneumatic controllers, natural gas may be released with every valve movement or continuously from the valve control pilot. Not all pneumatic controllers are gas driven. These "non-gas driven" pneumatic controllers use sources of power other than pressurized natural gas. Examples include solar, electric, and instrument air. At oil and gas locations with electrical service, non gas-driven controllers are typically used. Gas-driven pneumatic controllers are typically characterized as "high-bleed" or "low-bleed", where a high-bleed device releases at least 6 cubic feet of gas per hour. EPA evaluated the impact of requiring low-bleed controllers.

Storage vessels (TSD Chapter 7): Crude oil, condensate, and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically located at tank batteries. A tank battery refers to the collection of process equipment used to separate, treat, and store crude oil, condensate, natural gas, and produced water. The extracted products from productions wells enter the tank battery through the production header, which may collect product from many wells. Emissions from storage vessels are a result of working, breathing, and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flashing emission will occur in the storage stage. The two ways of controlling tanks with significant emissions would be to install a vapor recovery unit (VRU) and recover all the vapors from the tanks or to route the emissions from the tanks to a control device.

Well completions (TSD Chapter 4): In the oil and natural gas sector, well completions contain multi-phase processes with various sources of emissions. One specific emission source during completion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during activities that involve re-drilling or re-fracturing an existing well. Well completions include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production.

Hydraulic fracturing is one completion step for improving gas production where the reservoir rock is fractured with very high pressure fluid, typically water emulsion with proppant (generally sand) that "props open" the fractures after fluid pressure is reduced. Emissions are a result of the backflow of the fracture fluids and reservoir gas at high velocity necessary to lift excess proppant to the surface. This multi-phase mixture is often directed to a surface impoundment where natural gas and VOC vapors escape to the atmosphere during the collection of water, sand, and hydrocarbon liquids. As the fracture fluids are depleted, the backflow eventually contains more volume of natural gas from the formation. Thus, we estimate completions involving hydraulic fracturing vent substantially more natural gas, approximately 230 times more, than completions not involving hydraulic fracturing. Specifically, we estimate that uncontrolled well completion emissions for a hydraulically fractured well are about 23 tons of VOC, where emissions for a conventional gas well completion are around 0.1 ton VOC. Our data indicate that hydraulically fractured wells have higher emissions but we believe some wells that are not hydraulically fractured may have higher emissions than our data show, or in some cases, hydraulically fractured wells could have lower emissions that our data show.

Reduced emission completions, which are sometimes referred to as “green completions” or “flareless completions,” use equipment at the well site to capture and treat gas so it can be directed into the sales line and avoid emissions from venting. Equipment required to conduct a reduced emissions completion may include tankage, special gas-liquid-sand separator traps, and gas dehydration. Equipment costs associated with reduced emission completions will vary from well to well. Based on information provided to the EPA Natural Gas STAR program, 90 percent of gas potentially vented during a completion can be recovered during a reduced emission completion.

3.2.1.2 NESHAP Emission Points and Pollution Controls

A series of emissions controls will be required under the proposed NESHAP Amendments. This section provides a basic description of potential sources of emissions and the controls intended for each to facilitate the reader’s understanding of the economic impacts and subsequent benefits analysis section. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant technical memos which are published in the Docket. The memos are also referenced below.

Glycol dehydrators[5]: Once natural gas has been separated from any liquid materials or products (e.g., crude oil, condensate, or produced water), residual entrained water is removed from the natural gas by dehydration. Dehydration is necessary because water vapor may form hydrates, which are ice-like structures, and can cause corrosion in or plug equipment lines. The most widely used natural gas dehydration processes are glycol dehydration and solid desiccant

[5] Memorandum. Brown, Heather, EC/R Incorporated, to Bruce Moore and Greg Nizich, EPA/OAQPS/SPPD/FIG. Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT - Glycol Dehydrators: Impacts of MACT Review Options. July 17,2011.

dehydration. Solid desiccant dehydration, which is typically only used for lower throughputs, uses adsorption to remove water and is not a source of HAP emissions. Glycol dehydration is an absorption process in which a liquid absorbent, glycol, directly contacts the natural gas stream and absorbs any entrained water vapor in a contact tower or absorption column. The rich glycol, which has absorbed water vapor from the natural gas stream, leaves the bottom of the absorption column and is directed either to (1) a gas condensate glycol separator (GCG separator or flash tank) and then a reboiler or (2) directly to a reboiler where the water is boiled off of the rich glycol. The regenerated glycol (lean glycol) is circulated, by pump, into the absorption tower. The vapor generated in the reboiler is directed to the reboiler vent. The reboiler vent is a source of HAP emissions. In the glycol contact tower, glycol not only absorbs water but also absorbs selected hydrocarbons, including BTEX and n-hexane. The hydrocarbons are boiled off along with the water in the reboiler and vented to the atmosphere or to a control device.

The most commonly used control device is a condenser. Condensers not only reduce emissions, but also recover condensable hydrocarbon vapors that can be recovered and sold. In addition, the dry non-condensable off-gas from the condenser may be used as fuel or recycled into the production process or directed to a flare, incinerator, or other combustion device.

If present, the GCG separator (flash tank) is also a potential source of HAP emissions. Some glycol dehydration units use flash tanks prior to the reboiler to separate entrained gases, primarily methane and ethane from the glycol. The flash tank off-gases are typically recovered as fuel or recycled to the natural gas production header. However, the flash tank may also be vented directly to the atmosphere. Flash tanks typically enhance the reboiler condenser's emission reduction efficiency by reducing the concentration of non-condensable gases present in the stream prior to being introduced into the condenser.

Storage vessels: Please see the discussion of storage vessels in the NSPS section above.

3.2.2 Engineering Cost Analysis

In this section, we provide an overview of the engineering cost analysis used to estimate the additional private expenditures industry may make in order to comply with the proposed

NSPS and NESHAP amendments. A detailed discussion of the methodology used to estimate cost impacts is presented in series of memos published in the Docket as part of the TSD.

3.2.2.1 NSPS Sources

Table 3-1 shows the emissions sources, points, and controls analyzed in three NSPS regulatory options, which we term Option 1, Option 2, and Option 3. Option 2 was selected for proposal. The proposed Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly drilled natural gas wells that are hydraulically fractured. Option 2 also requires a subset of wells that are worked over, or recompleted, using hydraulic fracturing to implement RECs. The proposed Option 2 requires emissions reductions from reciprocating compressors at gathering and boosting stations, processing plants, transmission compressor stations, and underground storage facilities. The proposed Option 2 also requires emissions reductions from centrifugal compressors, processing plants, and transmission compressor stations. Finally, the proposed Option 2 requires emissions reductions from pneumatic controllers at oil and gas production facilities and natural gas transmission and storage and reductions from high throughput storage vessels.

Table 3-1 Emissions Sources, Points, and Controls Included in NSPS Options

Emissions Sources and Points	Emissions Control	Option 1	Option 2 (proposed)	Option 3
Well Completions of Post-NSPS Wells				
Hydraulically Fractured Gas Wells that Meet Criteria for Reduced Emissions Completion (REC)	REC	**X**	**X**	**X**
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC	Combustion	**X**	**X**	**X**
Conventional Gas Wells	Combustion			
Oil Wells	Combustion			
Well Recompletions				
Hydraulically Fractured Gas Wells (post-NSPS wells)	REC	**X**	**X**	**X**
Hydraulically Fractured Gas Wells (pre-NSPS wells)	REC		**X**	**X**
Conventional Gas Wells	Combustion			
Oil Wells	Combustion			
Equipment Leaks				
Well Pads	NSPS Subpart VV			**X**
Gathering and Boosting Stations	NSPS Subpart VV			**X**
Processing Plants	NSPS Subpart VVa		**X**	**X**
Transmission Compressor Stations	NSPS Subpart VV			**X**
Reciprocating Compressors				
Well Pads	Annual Monitoring/ Maintenance (AMM)			
Gathering/Boosting Stations	AMM	**X**	**X**	**X**
Processing Plants	AMM	**X**	**X**	**X**
Transmission Compressor Stations	AMM	**X**	**X**	**X**
Underground Storage Facilities	AMM	**X**	**X**	**X**
Centrifugal Compressors				
Processing Plants	Dry Seals/Route to Process or Control	**X**	**X**	**X**
Transmission Compressor Stations	Dry Seals/Route to Process or Control	**X**	**X**	**X**
Pneumatic Controllers -				
Oil and Gas Production	Low Bleed/Route to Process	**X**	**X**	**X**
Natural Gas Transmission and Storage	Low Bleed/Route to Process	**X**	**X**	**X**
Storage Vessels				
High Throughput	95% control	**X**	**X**	**X**
Low Throughput	95% control			

The distinction between Option 1 and the proposed Option 2 is the inclusion of completion combustion and REC requirements for recompletions at existing wells and an equipment leak standard for natural gas processing plants in Option 2. Option 2 requires the implementation of completion combustion and REC for existing wells as well as wells completed after the implementation date of the proposed NSPS. Option 1 applies the requirement only to new wells, not existing wells. The main distinction between proposed Option 2 and Option 3 is the inclusion of a suite of equipment leak standards. These equipment leak standards would apply at well pads, gathering and boosting stations, and transmission compressor stations. Option 1 differs from Option 3 in that it does not include the combustion and REC requirements at existing wells or the full suite of equipment leak standards.

Table 3-2 summarizes the unit level capital and annualized costs for the evaluated NSPS emissions sources and points. The detailed description of costs estimates is provided in the series of technical memos included in the TSD in the document, as referenced in Section 3.2.1 of this RIA. The table also includes the projected number of affected units. Four issues are important to note on Table 3-2: the approach to annualizing costs, the projection of affected units in the baseline; that capital and annualized costs are equated for RECs; and additional natural gas and hydrocarbon condensates that would otherwise be emitted to the environment are recovered from several control options evaluated in the NSPS review.

First, engineering capital costs were annualized using a 7 percent interest rate. However, different emissions control options were annualized using expected lifetimes that were determined to be most appropriate for individual options. For control options evaluated for the NSPS, the following lifetimes were used:

- Reduced emissions completions and combustion devices: 1 year (more discussion of the selection of a one-year lifetime follows in this section momentarily)
- Reciprocating compressors: 3 years
- Centrifugal compressors and pneumatic controllers: 10 years
- Storage vessels: 15 years
- Equipment leaks: 5 to 10 years, depending on specific control

To estimate total annualized engineering compliance costs, we added the annualized costs of each item without accounting for different expected lifetimes. An alternative approach would be to establish an overall, representative project time horizon and annualize costs after consideration of control options that would need to be replaced periodically within the given time horizon. For example, a 15 year project would require replacing reciprocating compressor-related controls five times, but only require a single installation of controls on storage vessels. This approach, however, is equivalent to the approach selected; that is to sum the annualized costs across options, without establishing a representative project time horizon.

Second, the projected number of affected units is the number of units that our analysis shows would be affected in 2015, the analysis year. The projected number of affected units accounts for estimates of the adoption of controls in absence of Federal regulation. While the procedures used to estimate adoption in absence of Federal regulation are presented in detail within the TSD, because REC requirements provide a significant component of the estimated emissions reductions and engineering compliance costs, it is worthwhile to go into some detail on the projected number of RECs within the RIA. We use EIA projections consistent with the Annual Energy Outlook 2011 to estimate the number of natural gas well completions with hydraulic fracturing in 2015, assuming that successful wells drilled in coal bed methane, shale, and tight sands used hydraulic fracturing. Based on this assumption, we estimate that 11,403 wells were successfully completed and used hydraulic fracturing. To approximate the number of wells that would not be required to perform RECs because of the absence of sufficient infrastructure, we draw upon the distinction in EIA analysis between exploratory and developmental wells. We assume exploratory wells do not have sufficient access to infrastructure to perform a REC and are exempt from the REC requirement. These 446 wells are removed from the REC estimate and are assumed to combust emissions using pit flares.

The number of hydraulically fractured recompletions of existing wells was approximated using assumptions found in Subpart W's TSD[6] and applied to well count data found in the proprietary HPDI® database. The underlying assumption is that wells found in coal bed

[6] U.S. Environmental Protection Agency (U.S. EPA). 2010. Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry: Background Technical Support Document. Climate Change Division. Washington, DC.

methane, shale, and tight sand formations require re-fracture, on average, every 10 years. In other words, 10 percent of the total wells classified as being performed with hydraulic fracturing would perform a recompletion in any given year. Natural gas well recompletions performed without hydraulic fracturing were based only on 2008 well data from HPDI®.

The number of completions and recompletions already controlling emissions in absence of a Federal regulation was estimated based on existing State regulations that require applicable control measures for completions and workovers in specific geographic locations. Based on this criterion, 15 percent of natural gas completions with hydraulic fracturing and 15 percent of existing natural gas workovers with hydraulic fracturing are estimated to be controlled by either flare or REC in absence of Federal regulations. Completions and recompletions without hydraulic fracturing were assumed as having no controls in absence of a Federal regulation. Following these procedures leads to an estimate of 9,313 completions of new wells and 12,050 recompletions of existing wells that will require either a REC under the proposed NSPS in 2015.

It should be noted that natural gas prices are stochastic and, historically, there have been periods where prices have increased or decreased rapidly. These price changes would be expected to affect adoption of emission reduction technologies in absence of regulation, particularly control measures such as RECs that capture emission significantly over short periods of time.

Third, for well completion requirements, annualized costs are set equal to capital costs. We chose to equate the capital and annualized cost because the completion requirements (combustion and RECs) are essentially one-shot events; the emissions controls are applied over the course of a well completion, which will typically range over a few days to a couple of weeks. After this relatively short period of time, there is no continuing control requirement, unless the well is again completed at a later date, sometimes years later. We reasoned that the absence of a continuing requirement makes it appropriate to equate capital and annualized costs.

Fourth, for annualized cost, we present two figures, the annualized costs with revenues from additional natural gas and condensate recovery and annualized costs without additional revenues this product recovery. Several emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOCs, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. When including the additional natural gas recovery in the cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. RECs also capture saleable condensates that would otherwise be lost to the environment. The engineering analysis assumes a REC will capture 34 barrels of condensate per REC and that the value of this condensate is $70/barrel.

The assumed price for natural gas is within the range of variation of wellhead prices for the 2010-11 period. The $4/Mcf is below the 2015 EIA-forecasted wellhead price, $4.22/Mcf in 2008 dollars. The $4/Mcf payment rate does not reflect any taxes or tax credits that might apply to producers implementing the control technologies. As natural gas prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional natural gas recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million in 2008 dollars.

As will be seen in subsequent analysis, the estimate of revenues from additional product recovery is critical to the economic impact analysis. However, before discussing this assumption in more depth, it is important to further develop the engineering estimates to contextualize the discussion and to provide insight into why, if it is profitable to capture natural gas emissions that are otherwise vented, producers may not already be doing so.

Table 3-3 presents the estimated nationwide compliance costs, emissions reductions, and VOC reduction cost-effectiveness broken down by emissions sources and points for those sources and points evaluated in the NSPS analysis. The reporting and recordkeeping costs for the proposed NSPS Option 2 are estimated at $18,805,398 and are included in Table 3-3. Because of time constraints, we were unable to estimate reporting and recordkeeping costs customized for Options 1 and 3; for these options, we use the same $18,805,398 for reporting and recordkeeping costs for these options.

As can be seen from Table 3-3 controls associated with well completions and recompletions of hydraulically fractured wells provide the largest potential for emissions reductions from evaluated emissions sources and points, as well as present the most significant compliance costs if revenue from additional natural gas recovery is not included. Emissions reductions from conventional natural gas wells and crude oil wells are clearly not as significant as the potential from hydraulically fractured wells, as was discussed in Section 3.2.1.1.

Several evaluated emissions sources and points are estimated to have net financial savings when including the revenue from additional natural gas recovery. These sources form the core of the three NSPS options evaluated in this RIA. Table 3-4 presents the estimated engineering costs, emissions reductions, and VOC reduction cost-effectiveness for the three NSPS options evaluated in the RIA. The resulting total national annualized cost impact of the proposed NSPS rule (Option 2) is estimated at $740 million per year without considering revenues from additional natural gas recovery. Annual costs for the proposed NSPS are estimated at -$45 million when revenue from additional natural gas recovery is included. All figures are in 2008 dollars.

Table 3-2 Summary of Capital and Annualized Costs per Unit for NSPS Emissions Points

Sources/Emissions Point	Projected No. of Affected Units	Capital Costs (2008$)	Per Unit Annualized Cost (2008$) Without Revenues from Additional Product Recovery	Per Unit Annualized Cost (2008$) With Revenues from Additional Product Recovery
Well Completions				
Hydraulically Fractured Gas Wells that Meet Criteria for REC	9,313	$33,237	$33,237	-$2,173
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	446	$3,523	$3,523	$3,523
Conventional Gas Wells	7,694	$3,523	$3,523	$3,523
Oil Wells	12,193	$3,523	$3,523	$3,523
Well Recompletions				
Hydraulically Fractured Gas Wells (existing wells)	12,050	$33,237	$33,237	-$2,173
Conventional Gas Wells	42,342	$3,523	$3,523	$3,523
Oil Wells	39,375	$3,523	$3,523	$3,523
Equipment Leaks				
Well Pads	4,774	$68,970	$23,413	$21,871
Gathering and Boosting Stations	275	$239,494	$57,063	$51,174
Processing Plants	29	$7,522	$45,160	$33,884
Transmission Compressor Stations	107	$96,542	$25,350	$25,350
Reciprocating Compressors				
Well Pads	6,000	$6,480	$3,701	$3,664
Gathering/Boosting Stations	210	$5,346	$2,456	$870
Processing Plants	209	$4,050	$2,090	-$2,227
Transmission Compressor Stations	20	$5,346	$2,456	$2,456
Underground Storage Facilities	4	$7,290	$3,349	$3,349
Centrifugal Compressors				
Processing Plants	16	$75,000	$10,678	-$123,730
Transmission Compressor Stations	14	$75,000	$10,678	-$77,622
Pneumatic Controllers -				
Oil and Gas Production	13,632	$165	$23	-$1,519
Natural Gas Trans. and Storage	67	$165	$23	$23
Storage Vessels				
High Throughput	304	$65,243	$14,528	$13,946
Low Throughput	17,086	$65,243	$14,528	$13,946

Table 3-3 Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015

		Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
Source/Emissions Point	**Emissions Control**	**Without Addl. Revenues**	**With Addl. Revenues**	**VOC**	**Methane**	**HAP**	**Without Addl. Revenues**	**With Addl. Revenues**
Well Completions (New Wells)								
Hydraulically Fractured Gas Wells	REC	$309,553,517	-$20,235,748	204,134	1,399,139	14,831	$1,516	-$99
Hydraulically Fractured Gas Wells	Combustion	$1,571,188	$1,571,188	9,801	67,178	712	$160	$160
Conventional Gas Wells	Combustion	$27,104,761	$27,104,761	857	5,875	62	$31,619	$31,619
Oil Wells	Combustion	$42,954,036	$42,954,036	83	88	0	$520,580	$520,580
Well Recompletions (Existing Wells)								
Hydraulically Fractured Gas Wells (existing wells)	REC	$400,508,928	-$26,181,572	264,115	1,810,245	19,189	$1,516	-$99
Conventional Gas Wells	Combustion	$149,164,257	$149,164,257	316	2,165	23	$472,227	$472,227
Oil Wells	Combustion	$138,711,979	$138,711,979	44	47	0	$3,134,431	$3,134,431
Equipment Leaks								
Well Pads	NSPS Subpart VV	$111,773,662	$104,412,154	10,646	38,287	401	$10,499	$9,808
Gathering and Boosting Stations	NSPS Subpart VV	$15,692,325	$14,072,850	2,340	8,415	88	$6,705	$6,013
Processing Plants	NSPS Subpart VVa	$1,309,650	$982,648	392	1,411	15	$3,343	$2,508
Transmission Compressor Stations	NSPS Subpart VV	$2,712,450	$2,712,450	261	9,427	8	$10,389	$10,389
Reciprocating Compressors								
Well Pads	Annual Monitoring/ Maintenance (AMM)	$22,204,209	$21,984,763	263	947	10	$84,379	$83,545
Gathering/Boosting Stations	AMM	$515,764	$182,597	400	1,437	15	$1,291	$457
Processing Plants	AMM	$436,806	-$465,354	1,082	3,892	41	$404	-$430
Transmission Compressor Stations	AMM	$47,892	$47,892	12	423	0	$4,093	$4,093
Underground Storage Facilities	AMM	$13,396	$13,396	2	87	0	$5,542	$5,542

Table 3-3 (continued) Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015

		Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
Source/Emissions Point	**Emissions Control**	**Without Addl. Revenues**	**With Addl. Revenues**	**VOC**	**Methane**	**HAP**	**Without Addl. Revenues**	**With Addl. Revenues**
Centrifugal Compressors								
Processing Plants	Dry Seals/Route to Process or Control	$170,853	-$1,979,687	288	3,183	10	$593	-$6,874
Transmission Compressor Stations	Dry Seals/Route to Process or Control	$149,496	-$1,086,704	43	1,546	1	$3,495	-$25,405
Pneumatic Controllers -								
Oil and Gas Production	Low Bleed/Route to Process	$320,071	-$20,699,918	25,210	90,685	952	$13	-$821
Natural Gas Trans. and Storage	Low Bleed/Route to Process	$1,539	$1,539	6	212	0	$262	$262
Storage Vessels								
High Throughput	95% control	$4,411,587	$4,234,856	29,654	6,490	876	$149	$143
Low Throughput	95% control	$248,225,012	$238,280,976	6,838	1,497	202	$36,298	$34,844

Table 3-4 Estimated Engineering Compliance Costs, NSPS (2008$)

	Option 1	Option 2 (Proposed)	Option 3
Capital Costs	$337,803,930	$738,530,998	$1,143,984,622
Annualized Costs			
Without Revenues from Additional Natural Gas Product Recovery	$336,163,858	$737,982,436	$868,160,873
With Revenues from Additional Natural Gas Product Recovery	-$19,496,449	-$44,695,374	$76,502,080
VOC Reductions (tons per year)	270,695	535,201	548,449
Methane Reduction (tons per year)	1,574,498	3,386,154	3,442,283
HAP Reductions (tons per year)	17,442	36,645	37,142
VOC Reduction Cost-Effectiveness ($/ton without additional product revenues)	$1,241.86	$1,378.89	$1,582.94
VOC Reduction Cost-Effectiveness ($/ton with additional product revenues)	-$72.02	-$83.51	$139.49

Note: the VOC reduction cost-effectiveness estimate assumes there is no benefit to reducing methane and HAP, which is not the case. We however present the per ton costs of reducing the single pollutant for illustrative purposes. As product prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional product recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million in 2008 dollars. The cost estimates for each regulatory option also include reporting and recordkeeping costs of $18,805,398.

As mentioned earlier, the single difference between Option 1 and the proposed Option 2 is the inclusion of RECs for recompletions of existing wells in Option 2. The implication of this inclusion in Option 2 is clear in Table 3-4, as the estimated engineering compliance costs without additional product revenue more than double and VOC emissions reductions also more than double. Meanwhile, the addition of equipment leaks standards in Option 3 increases engineering costs more than $400 million dollars in 2008 dollars, but only marginally increase estimates of emissions reductions of VOCs, methane, and HAPS.

As the price assumption is very influential on estimated impacts, we performed a simple sensitivity analysis of the influence of the assumed wellhead price paid to natural gas producers on the overall engineering costs estimate of the proposed NSPS. Figure 3-1 plots the annualized costs after revenues from natural gas product recovery have been incorporated (in millions of 2008 dollars) as a function of the assumed price of natural gas paid to producers at the wellhead for the recovered natural gas (represented by the sloped, dotted line). The vertical solid lines in the figure represent the natural gas price assumed in the RIA ($4.00/Mcf) for 2015 and the 2015 forecast by EIA in the 2011 Annual Energy Outlook ($4.22/Mcf) in 2008 dollars.

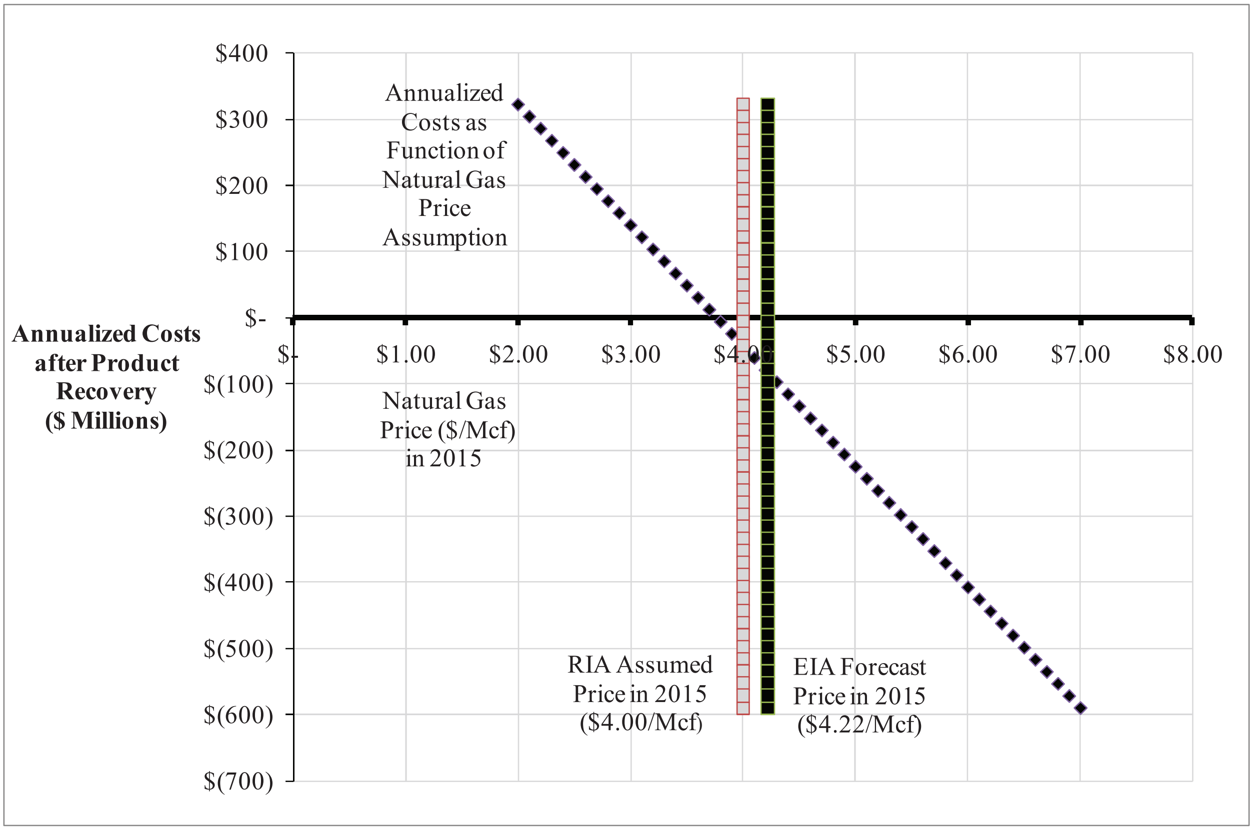

Figure 3-1 Sensitivity Analysis of Proposed NSPS Annualized Costs after Revenues from Additional Product Recovery are Included

As shown in Table 3-4, at the assumed $4/Mcf, the annualized costs are estimated at -$45 million. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook, the annualized costs are estimated at about -$90 million, which would approximately double the estimate of net cost savings of the proposed NSPS. As indicated by this difference, EPA has chosen a relatively conservative assumption (leading to an estimate of few savings and higher net costs) for the engineering costs analysis. The natural gas price at which the proposed NSPS breaks-even is around $3.77/Mcf. As mentioned earlier, a $1/Mcf change in the wellhead natural gas price leads to about a $180 million change in the annualized engineering costs of the proposed NSPS. Consequently, annualized engineering costs estimates would increase to about $140 million under a $3/Mcf price or decrease to about -$230 million under a $5/Mcf price.

It is additionally helpful to put the quantity of natural gas and condensate potentially recovered in the context of domestic production levels. To do so, it is necessary to make two adjustments. First, not all emissions reductions can be directed into production streams to be ultimately consumed by final consumers. Several controls require combustion of the natural gas rather than capture and direction into product streams. After adjusting estimates of national emissions reductions in Table 3-3 for these combustion-type controls, Options 1, 2, and 3 are estimated to capture about 83, 183, and 185 bcf of natural gas and 317,000, 726,000, and 726,000 barrels of condensate, respectively. For control options that are expected to recover natural gas products. Estimates of unit-level and nation-level product recovery are presented in Section 3 of the RIA. Note that completion-related requirements for new and existing wells generate all the condensate recovery for all NSPS regulatory options. For natural gas recovery, RECs contribute 77 bcf (92 percent) for Option 1, 176 bcf (97 percent) for Option 2, and 176 bcf (95 percent) for Option 3.

Table 3-5 Estimates of Control Unit-level and National Level Natural Gas and Condensate Recovery, NSPS Options, 2015

				Unit-level Product Recovery		Total Product Recovery	
Source/ Emissions Points	**Emissions Control**	**NSPS Option**	**Projected No. of Affected Units**	**Natural Gas Savings (Mcf/unit)**	**Condensate (bbl/unit)**	**Natural Gas Savings (Mcf)**	**Condensate (bbl)**
Well Completions							
Hydraulically Fractured Gas Wells	REC	1, 2, 3	9,313	8,258	34	76,905,813	316,657
Hydraulically Fractured Gas Wells	Combustion	1, 2, 3	446	0	0	0	0
Hydraulically Fractured Gas Wells (existing wells)	REC	2, 3	12,050	8,258	34	99,502,875	409,700
Equipment Leaks							
Well Pads	NSPS Subpart VV	3	4,774	386	0	1,840,377	0
Gathering and Boosting Stations	NSPS Subpart VV	3	275	1,472	0	404,869	0
Processing Plants	NSPS Subpart VVa	2, 3	29	2,819	0	81,750	0
Reciprocating Compressors							
Gathering/Boosting Stations	AMM	1, 2, 3	210	397	0	83,370	0
Processing Plants	AMM	1, 2, 3	375	1,079	0	404,677	0
Trans. Compressor Stations	AMM	1, 2, 3	199	1,122	0	223,374	0
Underground Storage Facilities	AMM	1, 2, 3	9	1,130	0	9,609	0
Centrifugal Compressors							
Processing Plants	Dry Seals/Route to Process or Ctrl	1, 2, 3	16	11,527	0	184,435	0
Trans. Compressor Stations	Dry Seals/Route to Process or Ctrl	1, 2, 3	14	5,716	0	80,018	0
Pneumatic Controllers -							
Oil and Gas Production	Low Bleed/Route to Process	1, 2, 3	13,632	386	0	5,254,997	0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	1, 2, 3	67	0	0	0	0
Processing Plants	Instrument Air	1, 2, 3	15	871.0	0	13,064	0
Storage Vessels							
High Throughput	95% control	1, 2, 3	304	146	0	44,189	0
Option 1 Total (Mcf)						**83,203,546**	**316,657**
Option 2 Total (Mcf)						**182,788,172**	**726,357**
Option 3 Total (Mcf)						**185,033,417**	**726,357**

A second adjustment to the natural gas quantities is necessary to account for nonhydrocarbon gases removed and gas that reinjected to repressurize wells, vented or flared, or consumed in production processes. Generally, wellhead production is metered at or near the wellhead and payments to producers are based on these metered values. In most cases, the natural gas is minimally processed at the meter and still contains impurities or co-products that must be processed out of the natural gas at processing plants. This means that the engineering cost estimates of revenues from additional natural gas recovery arising from controls implemented at the wellhead include payment for the impurities, such as the VOC and HAP content of the unprocessed natural gas. According to EIA, in 2009 the gross withdrawal of natural gas totaled 26,013 bcf, but 20,580 bcf was ultimately considered dry production (these figures exclude EIA estimates of flared and vented natural gas). Using these numbers, we apply a factor of 0.79 (20,580 bcf divided by 26,013 bcf) to the adjusted sums in the previous paragraph to estimate the volume of gas that is captured by controls that may ultimately by consumed by final consumers.

After making these adjustments, we estimate that Option 1 will potentially recover approximately 66 bcf, proposed Option 2 will potentially recover about 145 bcf, and Option 3 will potentially recover 146 bcf of natural gas that will ultimately be consumed by natural gas consumers.[7] EIA forecasts that the domestic dry natural gas production in 2015 will be 20,080 bcf. Consequently, Option 1, proposed Option 2, and Option 3 may recover production representing about 0.29 percent, 0.64 percent and 0.65 percent of domestic dry natural gas production predicted in 2015, respectively. These estimates, however, do not account for adjustments producers might make, once compliance costs and potential revenues from additional natural gas recovery factor into economic decisionmaking. Also, as discussed in the previous paragraph, these estimates do not include the nonhydrocarbon gases removed, natural gas reinjected to repressurize wells, and natural gas consumed in production processes, and therefore will be lower than the estimates of the gross natural gas captured by implementing controls.

[7] To convert U.S. short tons of methane to a cubic foot measure, we use the conversion factor of 48.04 Mcf per U.S. short ton.

Clearly, this discussion raises the question as to why, if emissions can be reduced profitably using environmental controls, more producers are not adopting the controls in their own economic self-interest. This question is made clear when examining simple estimates of the rate of return to installing emissions controls that, using the engineering compliance costs estimates, the estimates of natural gas product recovery, and assumed product prices (Table 3-6). The rates of return presented in are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula: product recovery, and assumed product prices (Table 3-6). The rates of return presented in are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula:

$$\text{rate of return} = \left(\frac{\text{estimated revenues}}{\text{estimated costs}} - 1 \right) \times 100 .$$

Table 3-6 Simple Rate of Return Estimate for NSPS Control Options

Emission Point	Control Option	Rate of Return
New Completions of Hydraulically Fractured Wells	Reduced Emissions Completions	6.5%
Re-completions of Existing Hydraulically Fractured Wells	Reduced Emissions Completions	6.5%
Reciprocating Compressors (Processing Plants)	Replace Packing Every 3 Years of Operation	208.3%
Centrifugal Compressors (Processing Plants)	Convert to Dry Seals	1158.7%
Centrifugal Compressors (Transmission Compressor Stations)	Convert to Dry Seals	726.9%
Pneumatic Controllers (Oil and Gas Production)	Low Bleed	6467.3%
Overall Proposed NSPS	**Low Bleed**	**6.1%**

Note: The table presents only control options where estimated revenues from natural gas product recovery exceeds estimated annualized engineering costs

Recall from Table 2-23 in the Industry Profile, that EIA estimates an industry-level rate of return on investments for various segments of the oil and natural gas industry. While the numbers varies greatly over time because of industry and economic factors, EIA estimates a 10.7 percent rate of return on investments for oil and natural gas production in 2008. While this amount is higher than the 6.5 percent rate estimated for RECs, it is significantly lower than the rate of returns estimated for other controls anticipated to have net savings.

Assuming financially rational producers, standard economic theory suggests that all oil and natural gas firms would incorporate all cost-effective improvements, which they are aware of, without government intervention. The cost analysis of this draft RIA nevertheless is based on the observation that emission reductions that appear to be profitable in our analysis have not been generally adopted. One possible explanation may be the difference between the average profit margin garnered by productive capital and the environmental capital where the primary motivation for installing environmental capital would be to mitigate the emission of pollutants and confer social benefits as discussed in Chapter 4.

Another explanation for why there appear to be negative cost control technologies that are not generally adopted is imperfect information. If emissions from the oil and natural gas sector are not well understood, firms may underestimate the potential financial returns to capturing emissions. Quantifying emissions is difficult and has been done in relatively few studies. Recently, however, advances in infrared imagery have made it possible to affordably visualize, if not quantify, methane emissions from any source using a handheld camera. This infrared camera has increased awareness within industry and among environmental groups and the public at large about the large number of emissions sources and possible scale of emissions from oil and natural gas production activities. Since, as discussed in the TSD chapter referenced above, 15 percent of new natural gas well completions with hydraulic fracturing and 15 percent of existing natural gas well recompletions with hydraulic fracturing are estimated to be controlled by either flare or REC in the baseline, it is unlikely that a lack of information will be a significant reason for these emission points to not be addressed in the absence of Federal regulation in 2015. However, for other emission points, a lack of information, or the cost associated with doing a feasibility study of potential emission capture technologies, may continue to prevent firms from adopting these improvements in the absence of regulation.

Another explanation is the cost associated with irreversibility associated with implementing these environmental controls are not reflected in the engineering cost estimates above. Due to the high volatility of natural gas prices, it is important to recognize the value of flexibility taken away from firms when requiring them to install and use a particular emissions capture technology. If a firm has not adopted the technology on its own, then a regulation mandating its use means the firm loses the option to postpone investment in the technology in order to pursue alternative investments today, and the option to suspend use of the technology if it becomes unprofitable in the future. Therefore, the full cost of the regulation to the firm is the engineering cost and the lost option value minus the revenues from the sale of the additional recovered product. In the absence of quantitative estimates of this option value for each emission point affected by the NSPS and NESHAP improvements, the costs presented in this RIA may underestimate the full costs faced by the affected firms. With these caveats in mind, EPA believes it is analytically appropriate to analyze costs and economic impacts costs presented in Table 3-2 and Table 3-3 using the additional product recovery and associated revenues.

3.2.2.2 NESHAP Sources

As discussed in Section 3.2.1.2, EPA examined three emissions points as part of its analysis for the proposed NESHAP amendments. Unlike the controls for the proposed NSPS, the controls evaluated under the proposed NESHAP amendments do not direct significant quantities of natural gas that would otherwise be flared or vented into the production stream. Table 3-7 shows the projected number of controls required, estimated unit-level capital and annualized costs, and estimated total annualized costs. The table also shows estimated emissions reductions for HAPs, VOCs, and methane, as well as a cost-effectiveness estimate for HAP reduction, based upon engineering (not social) costs.

Table 3-7 Summary of Estimated Capital and Annual Costs, Emissions Reductions, and HAP Reduction Cost-Effectiveness for Proposed NESHAP Amendments

					Emission Reductions (tons per year)			
Source/Emissions Point	**Projected No. of Controls Required**	**Capital Costs/ Unit (2008$)**	**Annualized Cost/Unit (2008$)**	**Total Annualized Cost (2008$)**	**HAP**	**VOC**	**Methane**	**HAP Reduction Cost-Effectiveness (2008$/ton)**
Production - Small Glycol Dehydrators	115	65,793	30,409	3,497,001	548	893	324	6,377
Transmission - Small Glycol Dehydrators	19	19,537	19,000	361,000	243	475	172	1,483
Storage Vessels	674	65,243	14,528	9,791,872	589	7,812	4,364	16,618
Reporting and Recordkeeping	---	196	2,933	2,369,755	---	---	---	---
Total	**808**			**16,019,871**	**1,381**	**9,243**	**4,859**	**10,576**

Note: Totals may not sum due to independent rounding.

Under the Proposed NESHAP Amendments, about 800 controls will be required, costing a total of $16.0 million (Table 3-7). We include reporting and recordkeeping costs as a unique line item showing these costs for the entire set of proposed amendments. These controls will reduce HAP emissions by about 1,400 tons, VOC emissions by about 9,200 tons, and methane by about 4,859 tons. The cost-per-ton to reduce HAP emissions is estimated at about $11,000 per ton. All figures are in 2008 dollars.

3.3 References

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4 BENEFITS OF EMISSIONS REDUCTIONS

4.1 Introduction

The proposed Oil and Natural Gas NSPS and NESHAP amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of the industry. While we expect that these avoided emissions will result in improvements in air quality and reduce health effects associated with exposure to HAPs, ozone, and fine particulate matter ($PM_{2.5}$), we have determined that quantification of those health benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no health benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. For the proposed NSPS, the HAP and climate benefits can be considered "co-benefits", and for the proposed NESHAP amendments, the ozone and $PM_{2.5}$ health benefits and climate benefits can be considered "co-benefits". These co-benefits occur because the control technologies used to reduce VOC emissions also reduce emissions of HAPs and methane.

The proposed NSPS is anticipated to prevent 37,000 tons of HAPs, 540,000 tons of VOCs, and 3.4 million tons of methane from new sources, while the proposed NESHAP amendments is anticipated reduce 1,400 tons of HAPs, 9,200 tons of VOCs, and 4,900 tons of methane from existing sources. The specific control technologies for the proposed NSPS is also anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 2,800 tons of CO, 7.6 tons of PM, and 1,000 tons of THC, and proposed NESHAP is anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC. Both rules would have additional emission changes associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons for the proposed NSPS and 93 thousand metric tons for the proposed NESHAP. As described in the subsequent sections, these pollutants are associated with substantial health effects, welfare effects, and climate effects. With the data available, we are not able to provide a credible benefits estimates for any of these pollutants for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information, and the highly localized nature of air quality responses associated with HAP and VOC reductions. In addition, we do not yet have interagency agreed upon valuation estimates for greenhouse gases other than CO_2 that could be used to value the climate co-benefits associated with avoiding methane emissions. Instead, we provide a qualitative assessment of the benefits and co-benefits as well as a break-even analysis in Chapter 6 of this RIA. A break-even analysis answers the question, “What would the benefits need to be for the benefits to exceed the costs.” While a break-even approach is not equivalent to a benefits analysis, we feel the results are illustrative, particularly in the context of previous benefit per ton estimates.

4.2 Direct Emission Reductions from the Oil and Natural Gas Rules

As described in Section 2 of this RIA, oil and natural gas operations in the U.S. include a variety of emission points for VOCs and HAPs including wells, processing plants, compressor stations, storage equipment, and transmission and distribution lines. These emission points are located throughout much of the country with significant concentrations in particular regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas gas compression stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density.

In implementing these rules, emission controls may lead to reductions in ambient $PM_{2.5}$ and ozone below the National Ambient Air Quality Standards (NAAQS) in some areas and assist other areas with attaining the NAAQS. Due to the high degree of variability in the responsiveness of ozone and $PM_{2.5}$ formation to VOC emission reductions, we are unable to determine how these rules might affect attainment status without air quality modeling data.[8] Because the NAAQS RIAs also calculate ozone and PM benefits, there are important differences worth noting in the design and analytical objectives of each RIA. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources. In short, NAAQS RIAs hypothesize, but do not predict, the control strategies that States may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. However,

[8] The responsiveness of ozone and $PM_{2.5}$ formation is discussed in greater detail in sections 4.4.1 and 4.5.1 of this RIA.

some costs and benefits estimated in this RIA account for the same air quality improvements as estimated in an illustrative NAAQS RIA.

By contrast, the emission reductions for this rule are from a specific class of well-characterized sources. In general, EPA is more confident in the magnitude and location of the emission reductions for these rules. It is important to note that emission reductions anticipated from these rules do not result in emission increases elsewhere (other than potential energy disbenefits). Emission reductions achieved under these and other promulgated rules will ultimately be reflected in the baseline of future NAAQS analyses, which would reduce the incremental costs and benefits associated with attaining the NAAQS. EPA remains forward looking towards the next iteration of the 5-year review cycle for the NAAQS, and as a result does not issue updated RIAs for existing NAAQS that retroactively update the baseline for NAAQS implementation. For more information on the relationship between the NAAQS and rules such as analyzed here, please see Section 1.2.4 of the SO_2 NAAQS RIA (U.S. EPA, 2010d). Table 4-1 shows the direct emission reductions anticipated for these rules by option. It is important to note that these benefits accrue at different spatial scales. HAP emission reductions reduce exposure to carcinogens and other toxic pollutants primarily near the emission source. Reducing VOC emissions would reduce precursors to secondary formation of $PM_{2.5}$ and ozone, which reduces exposure to these pollutants on a regional scale. Climate effects associated with long-lived greenhouse gases like methane are primarily at a global scale, but methane is also a precursor to ozone, a short-lived climate forcer that exhibits spatial and temporal variability.

Table 4-1 Direct Emission Reductions Associated with Options for the Oil and Natural Gas NSPS and NESHAP amendments in 2015 (short tons per year)

Pollutant	NESHAP Amendments	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3
HAPs	1,381	17,442	36,645	37,142
VOCs	9,243	270,695	535,201	548,449
Methane	4,859	1,574,498	3,386,154	3,442,283

4.3 Secondary Impacts Analysis for Oil and Gas Rules

The control techniques to avert leaks and vents of VOCs and HAPs are associated with several types of secondary impacts, which may partially offset the direct benefits of this rule. In this RIA, we refer to the secondary impacts associated with the specific control techniques as "producer-side" impacts.[9] For example, by combusting VOCs and HAPs, combustion increases emissions of carbon monoxide, NOx, particulate matter and other pollutants. In addition to "producer-side" impacts, these control techniques would also allow additional natural gas recovery, which would contribute to additional combustion of the recovered natural gas and ultimately a shift in the national fuel mix. We refer to the secondary impacts associated with the combustion of the recovered natural gas as "consumer-side" secondary impacts. We provide a conceptual diagram of both categories of secondary impacts in Figure 4-1.

[9] In previous RIAs, we have also referred to these impacts as energy disbenefits.

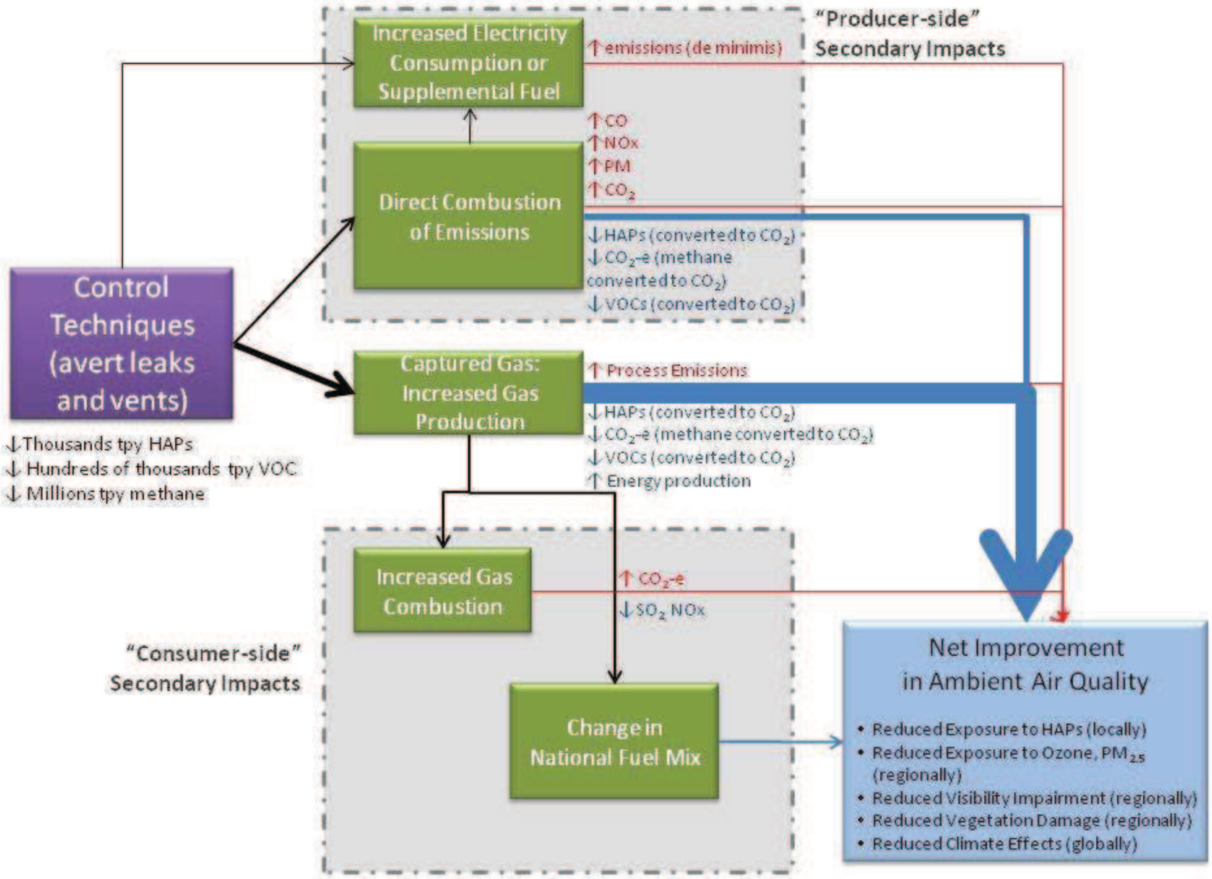

Figure 4-1 Conceptual Diagram of Secondary Impacts from Oil and Gas NSPS and NESHAP Amendments

Table 4-2 shows the estimated secondary impacts for the selected option for the "producer-side" impacts. Relative to the direct emission reductions anticipated from these rules, the magnitude of these secondary air pollutant impacts is small. Because the geographic distribution of these emissions from the oil and gas sector is not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009), we are unable to monetize the $PM_{2.5}$ disbenefits associated with the producer-side secondary impacts. In addition, it is not appropriate to monetize the disbenefits associated with the increased CO_2 emissions without monetizing the averted methane emissions because the overall global warming potential (GWP) is actually lower. Through the combustion process, methane emissions are converted to CO_2 emissions, which have 21 times less global warming potential compared to methane (IPCC, 2007).[10]

Table 4-2 Secondary Air Pollutant Impacts Associated with Control Techniques by Emissions Category ("Producer-Side") (tons per year)

Emissions Category	CO_2	NOx	PM	CO	THC
Completions of New Wells (NSPS)	587,991	302	5	1,644	622
Recompletions of Existing Wells (NSPS)	398,341	205	-	1,114	422
Pneumatic Controllers (NSPS)	22	1.0	2.6	-	-
Storage Vessels (NSPS)	856	0.5	0.0	2.4	0.9
Total NSPS	**987,210**	**508**	**7.6**	**2,760**	**1,045**
Total NESHAP (Storage Vessels)	**5,543**	**2.9**	**0.1**	**16**	**6**

For the "consumer-side" impacts associated with the NSPS, we modeled the impact of the regulatory options on the national fuel mix and associated CO_2-equivalent emissions (Table 4-3).[11] We provide the modeled results of the "consumer-side" CO_2-equivalent emissions in Table 7-12Error! Reference source not found.

The modeled results indicate that through a slight shift in the national fuel mix, the CO_2-equivalent emissions across the energy sector would increase by 1.6 million metric tons for the proposed NSPS option in 2015. This is in addition to the other secondary impacts and directly avoided emissions, for a total 62 million metric tons of CO_2-equivalent emissions averted as shown in Table 4-4. Due to time limitations under the court-ordered schedule, we did not estimate the other emissions (e.g., NOx, PM, SOx) associated with the additional national gas consumption or the change in the national fuel mix.

[10] This issue is discussed in more detail in Section 4.7 of this RIA.
[11] A full discussion of the energy modeling is available in Section 7 of this RIA.

Table 4-3 Modeled Changes in Energy-related CO_2-equivalent Emissions by Fuel Type for the Proposed Oil and Gas NSPS in 2015 (million metric tons) ("Consumer-Side")[1]

Fuel Type	NSPS Option 1 (million metric tons change in CO_2-e)	NSPS Option 2 (million metric tons change in CO_2-e) (Proposed)	NSPS Option 3 (million metric tons change in CO_2-e)
Petroleum	-0.51	-0.14	-0.18
Natural Gas	2.63	1.35	1.03
Coal	-3.04	0.36	0.42
Other	0.00	0.00	0.00
Total modeled Change in CO_2-e Emissions	**-0.92**	**1.57**	**1.27**

[1] These estimates reflect the modeled change in CO_2-e emissions using NEMS shown in Table 7-12. Totals may not sum due to independent rounding.

Table 4-4 Total Change in CO_2-equivalent Emissions including Secondary Impacts for the Proposed Oil and Gas NSPS in 2015 (million metric tons)

Emissions Source	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP Amendments
Averted CO_2-e Emissions from New Sources[1]	-30.00	-64.51	-65.58	-0.09
Additional CO_2-e Emissions from Combustion and Supplemental Energy (Producer-side)[2]	0.90	0.90	0.90	0.01
Total Modeled Change in Energy-related CO_2-e Emissions (Consumer-side)[3]	-0.92	1.57	1.27	--
Total Change in CO_2-e Emissions after Adjustment for Secondary Impacts	**-30.02**	**-62.04**	**-63.41**	**-0.09**

[1] This estimate reflects the GWP of the avoided methane emissions from new sources shown in Table 4-1 and has been converted from short tons to metric tons.

[2] This estimate represents the secondary producer-side impacts associated with additional CO_2 emissions from combustion and from additional electricity requirements shown in Table 4-2 and has been converted from short tons to metric tons. We use the producer-side secondary impacts associated with the proposed NSPS option as a surrogate for the impacts of the other options.

[3]This estimate reflects the modeled change in the energy–related consumer-side impacts shown in Table 4-3.

Totals may not sum due to independent rounding.

Based on these analyses, the net impact of both the direct and secondary impacts of these rules would be an improvement in ambient air quality, which would reduce exposure to various harmful pollutants, improve visibility impairment, reduce vegetation damage, and reduce potency of greenhouse gas emissions. Table 4-5 provides a summary of the direct and secondary emissions changes for each option.

Table 4-5 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP
Change in Direct Emissions	VOC	-270,000	-540,000	-550,000	-9,200
	Methane	-1,600,000	-3,400,000	-3,400,000	-4,900
	HAP	-17,000	-37,000	-37,000	-1,400
Change in Secondary Emissions (Producer-Side) [1]	CO_2	990,000	990,000	990,000	5,500
	NOx	510	510	510	2.9
	PM	7.6	7.6	7.6	0.1
	CO	2,800	2,800	2,800	16
	THC	1,000	1,000	1,000	6.0
Change in Secondary Emissions (Consumer-Side)	CO_2-e	-1,000,000	1,700,000	1,400,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e	-33,000,000	-68,000,000	-70,000,000	-96,000

[1] We use the producer-side secondary impacts associated with the proposed option as a surrogate for the impacts of the other options. Totals may not sum due to independent rounding.

4.4 Hazardous Air Pollutant (HAP) Benefits

Even though emissions of air toxics from all sources in the U.S. declined by approximately 42 percent since 1990, the 2005 National-Scale Air Toxics Assessment (NATA) predicts that most Americans are exposed to ambient concentrations of air toxics at levels that have the potential to cause adverse health effects (U.S. EPA, 2011d).[12] The levels of air toxics to which people are exposed vary depending on where people live and work and the kinds of activities in which they engage. In order to identify and prioritize air toxics, emission source types and locations that are of greatest potential concern, U.S. EPA conducts the NATA.[13] The most recent NATA was conducted for calendar year 2005 and was released in March 2011. NATA includes four steps:

[12] The 2005 NATA is available on the Internet at http://www.epa.gov/ttn/atw/nata2005/.

[13] The NATA modeling framework has a number of limitations that prevent its use as the sole basis for setting regulatory standards. These limitations and uncertainties are discussed on the 2005 NATA website. Even so, this modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting regulatory priorities, and informing the decision making process. U.S. EPA. (2011) 2005 National-Scale Air Toxics Assessment. http://www.epa.gov/ttn/atw/nata2005/

1) Compiling a national emissions inventory of air toxics emissions from outdoor sources

2) Estimating ambient and exposure concentrations of air toxics across the United States

3) Estimating population exposures across the United States

4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

Based on the 2005 NATA, EPA estimates that about 5 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer risk is about 50 in a million. Nationwide, the key pollutants that contribute most to the overall cancer risks are formaldehyde and benzene.[14,15] Secondary formation (e.g., formaldehyde forming from other emitted pollutants) was the largest contributor to cancer risks, while stationary, mobile and background sources contribute almost equal portions of the remaining cancer risk.

Noncancer health effects can result from chronic,[16] subchronic,[17] or acute[18] inhalation exposures to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems. According to the 2005 NATA, about three-fourths of the U.S. population was exposed to an average chronic concentration of air toxics that has the potential for adverse noncancer respiratory health effects. Results from the 2005 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

[14] Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2005 NATA risk estimates can be found at http://www.epa.gov/ttn/atw/nata1999/riskbg.html#Z2.

[15] Details about the overall confidence of certainty ranking of the individual pieces of NATA assessments including both quantitative (e.g., model-to-monitor ratios) and qualitative (e.g., quality of data, review of emission inventories) judgments can be found at http://www.epa.gov/ttn/atw/nata/roy/page16.html.

[16] Chronic exposure is defined in the glossary of the Integrated Risk Information (IRIS) database (http://www.epa.gov/iris) as repeated exposure by the oral, dermal, or inhalation route for more than approximately 10% of the life span in humans (more than approximately 90 days to 2 years in typically used laboratory animal species).

[17] Defined in the IRIS database as repeated exposure by the oral, dermal, or inhalation route for more than 30 days, up to approximately 10% of the life span in humans (more than 30 days up to approximately 90 days in typically used laboratory animal species).

[18] Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

Figure 4-2 and Figure 4-3 depict the estimated census tract-level carcinogenic risk and noncancer respiratory hazard from the assessment. It is important to note that large reductions in HAP emissions may not necessarily translate into significant reductions in health risk because toxicity varies by pollutant, and exposures may or may not exceed levels of concern. For example, acetaldehyde mass emissions are more than double acrolein emissions on a national basis, according to EPA's 2005 National Emissions Inventory (NEI). However, the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is considerably lower than that for acetaldehyde, suggesting that acrolein could be potentially more toxic than acetaldehyde.[19] Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

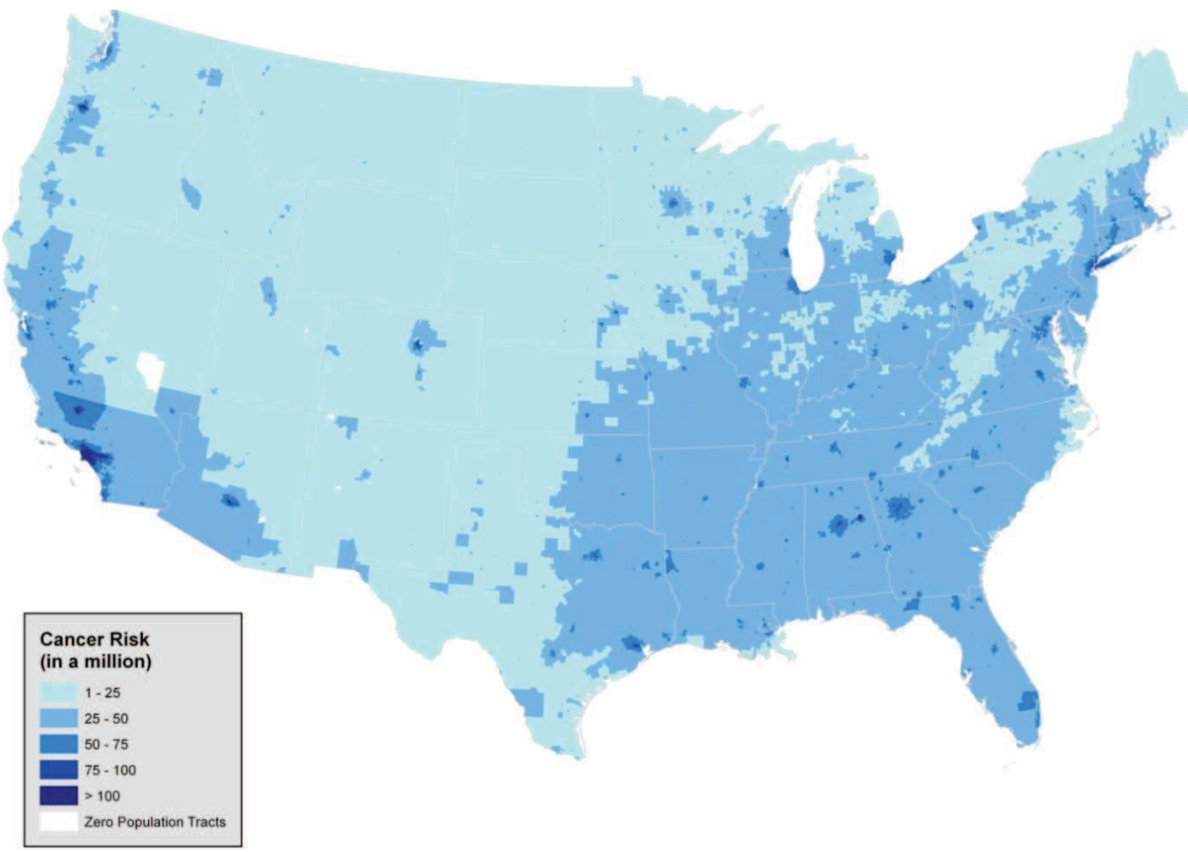

Figure 4-2 Estimated Chronic Census Tract Carcinogenic Risk from HAP exposure from outdoor sources (2005 NATA)

[19] Details on the derivation of IRIS values and available supporting documentation for individual chemicals (as well as chemical values comparisons) can be found at http://cfpub.epa.gov/ncea/iris/compare.cfm.

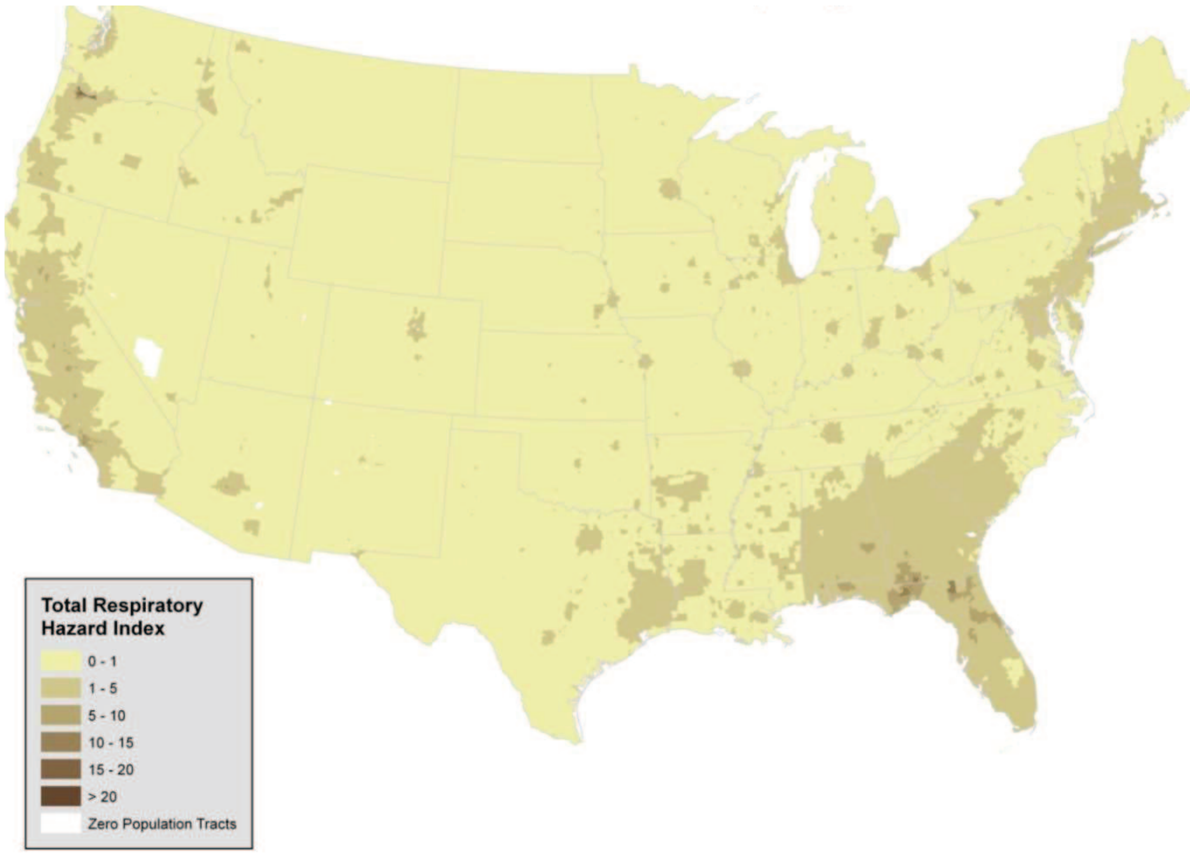

Figure 4-3 Estimated Chronic Census Tract Noncancer (Respiratory) Risk from HAP exposure from outdoor sources (2005 NATA)

Due to methodology and data limitations, we were unable to estimate the benefits associated with the hazardous air pollutants that would be reduced as a result of these rules.. In a few previous analyses of the benefits of reductions in HAPs, EPA has quantified the benefits of potential reductions in the incidences of cancer and non-cancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) developed through risk assessment procedures.[20] These URFs are designed to be conservative, and as such, are more likely to represent the high end of the distribution of risk rather than a best or most likely estimate of risk. As the purpose of a benefit analysis is to describe the benefits most likely to occur from a reduction in pollution, use of high-end, conservative risk estimates would overestimate the

[20]The unit risk factor is a quantitative estimate of the carcinogenic potency of a pollutant, often expressed as the probability of contracting cancer from a 70-year lifetime continuous exposure to a concentration of one µg/m^3 of a pollutant.

benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates in benefit analyses (U.S. EPA-SAB, 2002). Since this time, EPA has continued to develop better methods for analyzing the benefits of reductions in HAPs.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 2011a), EPA conducted a case study analysis of the health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act (IEc, 2009). While reviewing the draft report, EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAPs) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008).

In 2009, EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAPs. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn et al., 2011).

In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAPs, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAPs in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAPs anticipated to be reduced by these rules and we summarize the results of the residual risk assessment for the Risk and Technology Review (RTR). EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk.

Available emissions data show that several different HAPs are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAPs make up a large percentage the total

HAP emissions by mass from the oil and gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2011a). In the subsequent sections, we describe the health effects associated with the main HAPs of concern from the oil and natural gas sector: benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane. These rules combined are anticipated to avoid or reduce 58,000 tons of HAPs per year. With the data available, it was not possible to estimate the tons of each individual HAP that would be reduced.

EPA conducted a residual risk assessment for the NESHAP rule (U.S. EPA, 2011c). The results for oil and gas production indicate that maximum lifetime individual cancer risks could be 30 in-a-million for existing sources before and after controls with a cancer incidence of 0.02 before and after controls. For existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with a cancer incidence that decreases from 0.001 before controls to 0.0002 after controls. Benzene is the primary cancer risk driver. The results also indicate that significant noncancer impacts from existing sources are unlikely, especially after controls. EPA did not conduct a risk assessment for new sources affected by the NSPS. However, it is important to note that the magnitude of the HAP emissions avoided by new sources with the NSPS are more than an order of magnitude higher than the HAP emissions reduced from existing sources with the NESHAP.

4.4.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[21,22,23] EPA states in its IRIS database that data indicate a causal

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[21] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[22] International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345-389, 1982.

[23] Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691-3695.

relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human Services (DHHS) has characterized benzene as a known human carcinogen.[24,25] A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[26,27] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[28,29] In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.[30,31,32,33] EPA's IRIS program has not yet evaluated these new data.

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[24] International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[25] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: http://ntp.niehs.nih.gov/go/16183.

[26] Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193-197.

[27] Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541-554.

[28] Rothman, N., G.L. Li, M. Dosemeci, W.E. Bechtold, G.E. Marti, Y.Z. Wang, M. Linet, L.Q. Xi, W. Lu, M.T. Smith, N. Titenko-Holland, L.P. Zhang, W. Blot, S.N. Yin, and R.B. Hayes (1996) Hematotoxicity among Chinese workers heavily exposed to benzene. Am. J. Ind. Med. 29: 236-246.

[29] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene (Noncancer Effects). Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[30] Qu, O.; Shore, R.; Li, G.; Jin, X.; Chen, C.L.; Cohen, B.; Melikian, A.; Eastmond, D.; Rappaport, S.; Li, H.; Rupa, D.; Suramaya, R.; Songnian, W.; Huifant, Y.; Meng, M.; Winnik, M.; Kwok, E.; Li, Y.; Mu, R.; Xu, B.; Zhang, X.; Li, K. (2003). HEI Report 115, Validation & Evaluation of Biomarkers in Workers Exposed to Benzene in China.

[31] Qu, Q., R. Shore, G. Li, X. Jin, L.C. Chen, B. Cohen, et al. (2002). Hematological changes among Chinese workers with a broad range of benzene exposures. Am. J. Industr. Med. 42: 275-285.

[32] Lan, Qing, Zhang, L., Li, G., Vermeulen, R., et al. (2004). Hematotoxically in Workers Exposed to Low Levels of Benzene. Science 306: 1774-1776.

[33] Turtletaub, K.W. and Mani, C. (2003). Benzene metabolism in rodents at doses relevant to human exposure from Urban Air. Research Reports Health Effect Inst. Report No.113.

4.4.2 *Toluene*[34]

Under the 2005 Guidelines for Carcinogen Risk Assessment, there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

4.4.3 *Carbonyl sulfide*

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate

[34] All health effects language for this section came from: U.S. EPA. 2005. "Full IRIS Summary for Toluene (CASRN 108-88-3)" Environmental Protection Agency, Integrated Risk Information System (IRIS), Office of Health and Environmental Assessment, Environmental Criteria and Assessment Office, Cincinnati, OH. Available on the Internet at <http://www.epa.gov/iris/subst/0118.htm>.

the eyes and skin in humans.[35] No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under U.S. EPA's IRIS program for evidence of human carcinogenic potential.[36]

4.4.4 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral cavities in male and female rats exposed to ethylbenzene via the oral route.[37,38] The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP).[39,40] The NTP (1999) carried out a chronic inhalation

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[35] Hazardous Substances Data Bank (HSDB), online database). US National Library of Medicine, Toxicology Data Network, available online at http://toxnet.nlm.nih.gov/. Carbonyl health effects summary available at http://toxnet.nlm.nih.gov/cgi-bin/sis/search/r?dbs+hsdb:@term+@rn+@rel+463-58-1.

[36] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Carbonyl Sulfide. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0617.htm.

[37] Maltoni C, Conti B, Giuliano C and Belpoggi F, 1985. Experimental studies on benzene carcinogenicity at the Bologna Institute of Oncology: Current results and ongoing research. Am J Ind Med 7:415-446.

[38] Maltoni C, Ciliberti A, Pinto C, Soffritti M, Belpoggi F and Menarini L, 1997. Results of long-term experimental carcinogenicity studies of the effects of gasoline, correlated fuels, and major gasoline aromatics on rats. Annals NY Acad Sci 837:15-52.

[39] International Agency for Research on Cancer (IARC), 2000. Monographs on the Evaluation of Carcinogenic Risks to Humans. Some Industrial Chemicals. Vol. 77, p. 227-266. IARC, Lyon, France.

bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

4.4.5 Mixed xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely-related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects.[41] Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys.[42] Long-term inhalation exposure to xylenes in humans has been associated with a number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination.[43] EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

4.4.6 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central

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[40] National Toxicology Program (NTP), 1999. Toxicology and Carcinogenesis Studies of Ethylbenzene (CAS No. 100-41-4) in F344/N Rats and in B6C3F1 Mice (Inhalation Studies). Technical Report Series No. 466. NIH Publication No. 99-3956. U.S. Department of Health and Human Services, Public Health Service, National Institutes of Health. NTP, Research Triangle Park, NC.

[41] U.S. Environmental Protection Agency (U.S. EPA). 2003. Integrated Risk Information System File for Mixed Xylenes. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0270.htm.

[42] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53.

[43] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53.

nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.[44]

4.4.7 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by these rules, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in EPA's IRIS database.[45]

4.5 VOCs

4.5.1 VOCs as a PM2.5 precursor

This rulemaking would reduce emissions of VOCs, which are a precursor to $PM_{2.5.}$ Most VOCs emitted are oxidized to carbon dioxide (CO_2) rather than to PM, but a portion of VOC emission contributes to ambient $PM_{2.5}$ levels as organic carbon aerosols (U.S. EPA, 2009a). Therefore, reducing these emissions would reduce $PM_{2.5}$ formation, human exposure to $PM_{2.5}$, and the incidence of $PM_{2.5}$-related health effects. However, we have not quantified the $PM_{2.5}$-related benefits in this analysis. Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution. Given that a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions and the extremely small amount of VOC emissions from this sector relative to the entire VOC inventory it is unlikely this sector has a large contribution to

[44] U.S. EPA. 2005. Guidelines for Carcinogen Risk Assessment. EPA/630/P-03/001B. Risk Assessment Forum, Washington, DC. March. Available on the Internet at <http://www.epa.gov/ttn/atw/cancer_guidelines_final_3-25-05.pdf>.

[45] U.S. EPA Integrated Risk Information System (IRIS) database is available at: www.epa.gov/iris

ambient secondary organic carbon aerosols. Photochemical models typically estimate secondary organic carbon from anthropogenic VOC emissions to be less than 0.1 $\mu g/m^3$.

Due to time limitations under the court-ordered schedule, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of $PM_{2.5}$ formation to VOC emission reductions, we are unable to estimate the effect that reducing VOCs will have on ambient $PM_{2.5}$ levels without air quality modeling.

4.5.2 $PM_{2.5}$ health effects and valuation

Reducing VOC emissions would reduce $PM_{2.5}$ formation, human exposure, and the incidence of $PM_{2.5}$-related health effects. Reducing exposure to $PM_{2.5}$ is associated with significant human health benefits, including avoiding mortality and respiratory morbidity. Researchers have associated $PM_{2.5}$- exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009a). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to $PM_{2.5}$ (e.g., U.S. EPA (2010c)). These health effects include premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, hospital admissions, and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital and ER visits, work loss days, restricted activity days, and respiratory symptoms. Although EPA has not quantified these effects in previous benefits analyses, the scientific literature suggests that exposure to $PM_{2.5}$ is also associated with adverse effects on birth weight, pre-term births, pulmonary function, other cardiovascular effects, and other respiratory effects (U.S. EPA, 2009a).

EPA assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2009a). Based on our review of the current body of scientific literature, EPA estimates PM-related mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of $PM_{2.5}$ in the underlying epidemiology studies.

Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). Using the estimates in Fann, Fulcher, and Hubbell (2009), the monetized benefit-per-ton of reducing VOC emissions in nine urban areas of the U.S. ranges from $560 in Seattle, WA to $5,700 in San Joaquin, CA, with a national average of $2,400. These estimates assume a 50 percent reduction in VOCs, the Laden et al. (2006) mortality function (based on the Harvard Six City Study, a large cohort epidemiology study in the Eastern U.S.), an analysis year of 2015, and a 3 percent discount rate.

Based on the methodology from Fann, Fulcher, and Hubbell (2009), we converted their estimates to 2008$ and applied EPA's current VSL estimate.[46] After these adjustments, the range of values increases to $680 to $7,000 per ton of VOC reduced for Laden et al. (2006). Using alternate assumptions regarding the relationship between $PM_{2.5}$ exposure and premature mortality from empirical studies and supplied by experts (Pope et al., 2002; Laden et al., 2006; Roman et al., 2008), additional benefit-per-ton estimates are available from this dataset, as shown in Table 4-6. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) because they are both well-designed and peer reviewed studies, and EPA provides the benefit estimates derived from expert opinions in Roman et al. (2008) as a characterization of uncertainty. In addition to the range of benefits based on epidemiology studies, this study also provided a range of benefits associated with reducing emissions in eight specific urban areas. The range of VOC benefits that reflects the adjustments as well as the range of epidemiology studies and the range of the urban areas is $280 to $7,000 per ton of VOC reduced.

While these ranges of benefit-per-ton estimates provide useful context for the break-even analysis, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship

[46] For more information regarding EPA's current VSL estimate, please see Section 5.4.4.1 of the RIA for the proposed Federal Transport Rule (U.S. EPA, 2010a). EPA continues to work to update its guidance on valuing mortality risk reductions.

between VOC emissions and $PM_{2.5}$, these factors lead us to conclude that the available VOC benefit per ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

Table 4-6 Monetized Benefits-per-Ton Estimates for VOCs (2008$)

Area	Pope et al.	Laden et al.	Expert A	Expert B	Expert C	Expert D	Expert E	Expert F	Expert G	Expert H	Expert I	Expert J	Expert K	Expert L
Atlanta	$620	$1,500	$1,600	$1,200	$1,200	$860	$2,000	$1,100	$730	$920	$1,200	$980	$250	$940
Chicago	$1,500	$3,800	$4,000	$3,100	$3,000	$2,200	$4,900	$2,800	$1,800	$2,300	$3,000	$2,500	$600	$2,400
Dallas	$300	$740	$780	$610	$590	$420	$960	$540	$360	$450	$590	$480	$120	$460
Denver	$720	$1,800	$1,800	$1,400	$1,400	$1,000	$2,300	$1,300	$850	$1,100	$1,400	$1,100	$280	$850
NYC/ Philadelphia	$2,100	$5,200	$5,500	$4,300	$4,200	$3,000	$6,900	$3,900	$2,500	$3,200	$4,200	$3,400	$830	$3,100
Phoenix	$1,000	$2,500	$2,600	$2,000	$2,000	$1,400	$3,300	$1,800	$1,200	$1,500	$2,000	$1,600	$400	$1,500
Salt Lake	$1,300	$3,100	$3,300	$2,600	$2,500	$1,800	$4,100	$2,300	$1,500	$1,900	$2,500	$2,100	$530	$2,000
San Joaquin	$2,900	$7,000	$7,400	$5,800	$5,600	$4,000	$9,100	$5,200	$3,400	$4,300	$5,600	$4,600	$1,300	$4,400
Seattle	$280	$680	$720	$530	$550	$390	$890	$500	$330	$420	$550	$450	$110	$330
National average	**$1,200**	**$3,000**	**$3,200**	**$2,400**	**$2,400**	**$1,700**	**$3,900**	**$2,200**	**$1,400**	**$1,800**	**$2,400**	**$1,900**	**$490**	**$1,800**

* These estimates assume a 50 percent reduction in VOC emissions, an analysis year of 2015, and a 3 percent discount rate. All estimates are rounded to two significant digits. These estimates have been updated from Fann, Fulcher, and Hubbell (2009) to reflect a more recent currency year and EPA's current VSL estimate. Using a discount rate of 7 percent, the benefit-per-ton estimates would be approximately 9 percent lower. Assuming a 75 percent reduction in VOC emissions would increase the benefit-per-ton estimates by approximately 4 percent to 52 percent. Assuming a 25 percent reduction in VOC emissions would decrease the benefit-per-ton estimates by 5 percent to 52 percent. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) and provides the benefits estimates derived from the expert functions from Roman et al. (2008) as a characterization of uncertainty.

4.5.3 *Organic PM welfare effects*

According to the residual risk assessment for this sector (U.S. EPA, 2011a), persistent and bioaccumulative HAP reported as emissions from oil and gas operations include polycyclic organic matter (POM). POM defines a broad class of compounds that includes the polycyclic aromatic hydrocarbon compounds (PAHs). Several significant ecological effects are associated with deposition of organic particles, including persistent organic pollutants, and PAHs (U.S. EPA, 2009a).

PAHs can accumulate in sediments and bioaccumulate in freshwater, flora, and fauna. The uptake of organics depends on the plant species, site of deposition, physical and chemical properties of the organic compound and prevailing environmental conditions (U.S. EPA, 2009a). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. Deposition of PM to surfaces in urban settings increases the metal and organic component of storm water runoff. This atmospherically-associated pollutant burden can then be toxic to aquatic biota. The contribution of atmospherically deposited PAHs to aquatic food webs was demonstrated in high elevation mountain lakes with no other anthropogenic contaminant sources.

The recently completed Western Airborne Contaminants Assessment Project (WACAP) is the most comprehensive database on contaminant transport and PM depositional effects on sensitive ecosystems in the Western U.S. (Landers et al., 2008). In this project, the transport, fate, and ecological impacts of anthropogenic contaminants from atmospheric sources were assessed from 2002 to 2007 in seven ecosystem components (air, snow, water, sediment, lichen, conifer needles, and fish) in eight core national parks. The study concluded that bioaccumulation of semi-volatile organic compounds occurred throughout park ecosystems, an elevational gradient in PM deposition exists with greater accumulation in higher altitude areas, and contaminants accumulate in proximity to individual agriculture and industry sources, which is counter to the original working hypothesis that most of the contaminants would originate from Eastern Europe and Asia.

4.5.4 Visibility Effects

Reducing secondary formation of $PM_{2.5}$ would improve visibility throughout the U.S. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Suspended particles and gases degrade visibility by scattering and absorbing light. Higher visibility impairment levels in the East are due to generally higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Previous analyses (U.S. EPA, 2006b; U.S. EPA, 2010c; U.S. EPA, 2011a) show that visibility benefits are a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility related benefits, nor are we able to determine whether VOC emission reductions would be likely to have a significant impact on visibility in urban areas or Class I areas.

4.6 VOCs as an Ozone Precursor

This rulemaking would reduce emissions of VOCs, which are also precursors to secondary formation of ozone. Ozone is not emitted directly into the air, but is created when its two primary components, volatile organic compounds (VOC) and oxides of nitrogen (NOx), combine in the presence of sunlight. In urban areas, compounds representing all classes of VOCs and CO are important compounds for ozone formation, but biogenic VOCs emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2006a). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. However, we have not quantified the ozone-related benefits in this analysis for several reasons. First, previous rules have shown that the monetized benefits associated with reducing ozone exposure are generally smaller than PM-related benefits, even when ozone is the pollutant targeted for control (U.S. EPA, 2010a). Second, the complex non-linear chemistry of ozone formation introduces uncertainty to the development and application of a benefit-per-ton estimate. Third, the impact of reducing VOC emissions is spatially heterogeneous depending on local air chemistry. Urban areas with a high population concentration are often VOC-limited, which means that ozone is most effectively reduced by lowering VOCs. Rural areas and downwind suburban areas are often NOx-limited, which means that ozone concentrations are most effectively reduced by lowering NOx emissions, rather than lowering emissions of VOCs. Between these areas, ozone is relatively insensitive to marginal changes in both NOx and VOC.

Due to time limitations under the court-ordered schedule, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of ozone formation to VOC emission reductions, we are unable to estimate the effect that reducing VOCs will have on ambient ozone concentrations without air quality modeling.

4.6.1 Ozone health effects and valuation

Reducing ambient ozone concentrations is associated with significant human health benefits, including mortality and respiratory morbidity (U.S. EPA, 2010a). Epidemiological researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2006c). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to ozone (e.g., U.S. EPA, 2010a; U.S. EPA, 2011a). These health effects include respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days, as well as premature mortality. Although EPA has not quantified these effects in benefits analyses previously, the scientific literature is suggestive that exposure to ozone is also associated with chronic respiratory damage and premature aging of the lungs.

In a recent EPA analysis, EPA estimated that reducing 15,000 tons of VOCs from industrial boilers resulted in \$3.6 to \$15 million of monetized benefits from reduced ozone exposure (U.S. EPA, 2011b).[47] This implies a benefit-per-ton for ozone reductions of \$240 to \$1,000 per ton of VOCs reduced. While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in the boiler analysis. Therefore, we do not believe that those

[47] While EPA has estimated the ozone benefits for many scenarios, most of these scenarios also reduce NOx emissions, which make it difficult to isolate the benefits attributable to VOC reductions.

estimates to provide useful estimates of the monetized benefits of these rules, even as a bounding exercise.

4.6.2 Ozone vegetation effects

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2006a). Sensitivity to ozone is highly variable across species, with over 65 plan species identified as "ozone-sensitive", many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced crop yields, visible foliar injury, reduced plant vigor (e.g., increased susceptibility to harsh weather, disease, insect pest infestation, and competition), species composition shift, and changes in ecosystems and associated ecosystem services.

4.6.3 Ozone climate effects

Ozone is a well-known short-lived climate forcing (SLCF) greenhouse gas (GHG) (U.S. EPA, 2006a). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). A recent United Nations Environment Programme (UNEP) study reports that the threefold increase in ground level ozone during the past 100 years makes it the third most important contributor to human contributed climate change behind CO_2 and methane. This discernable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles. This study provides the most comprehensive analysis to date of the benefits of measures to reduce SLCF gases including methane, ozone, and black carbon assessing the health, climate, and agricultural benefits of a suite of mitigation technologies. The report concludes that the climate is changing now, and these changes have the potential to "trigger abrupt transitions such as the release of carbon from thawing permafrost and biodiversity loss" (UNEP 2011). While reducing long-lived GHGs such as CO_2 is necessary to protect against long-term climate change, reducing SLCF gases including ozone is beneficial and will slow the rate of climate change within the first half of this century (UNEP 2011).

4.7 Methane (CH_4)

4.7.1 Methane as an ozone precursor

This rulemaking would reduce emissions of methane, a long-lived GHG and also a precursor to ozone. In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2006a). Unlike NOx and VOCs, which affect ozone concentrations regionally and at hourly time scales, methane emission reductions require several decades for the ozone response to be fully realized, given methane's relatively long atmospheric lifetime (HTAP, 2010). Studies have shown that reducing methane can reduce global background ozone concentrations over several decades, which would benefit both urban and rural areas (West et al., 2006). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. The health, welfare, and climate effects associated with ozone are described in the preceding sections. Without air quality modeling, we are unable to estimate the effect that reducing methane will have on ozone concentrations at particular locations.

4.7.2 Methane climate effects and valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that once emitted into the atmosphere absorbs terrestrial infrared radiation which contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. According to the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (2007), in 2004 the cumulative changes in methane concentrations since preindustrial times contributed about 14 percent to global warming due to anthropogenic GHG sources, making methane the second leading long-lived climate forcer after CO_2 globally. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

Processes in the oil and gas category emit significant amounts of methane. The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 ($MMtCO_2$-e). In 2009, total methane emissions from the oil and gas industry represented nearly 40 percent of the total methane emissions from all sources and account for about 5 percent of all CO_2-equivalent (CO_2-e) emissions in the U.S., with natural gas systems being the single largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2011b, Table ES-2). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 $MMtCO_2$-e. The total methane emissions from Petroleum and Natural Gas Systems based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus Shale, is approximately 330 $MMtCO_2$-e.

This rulemaking proposes emission control technologies and regulatory alternatives that will significantly decrease methane emissions from the oil and natural gas sector in the United States. The regulatory alternative proposed for this rule is expected to reduce methane emissions annually by about 3.4 million short tons or approximately 65 million metric tons CO_2-e. These reductions represent about 26 percent of the GHG emissions for this sector reported in the 1990-2009 U.S. GHG Inventory (251.55 $MMTCO_2$-e). This annual CO_2-e reduction becomes about 62 million metric tons when the secondary impacts associated with increased combustion and supplemental energy use on the producer side and CO_2-e emissions from changes in consumption patterns previously discussed are considered. However, it is important to note the emissions reductions are based upon predicted activities in 2015; EPA did not forecast sector-level emissions to 2015 for this rulemaking. The climate co-benefit from these reductions are equivalent of taking approximately 11 million typical passenger cars off the road or eliminating electricity use from about 7 million typical homes each year.[48]

EPA estimates the social benefits of regulatory actions that have a small or "marginal" impact on cumulative global CO_2 emissions using the "social cost of carbon" (SCC). The SCC is an estimate of the net present value of the flow of monetized damages from a one metric ton increase in CO_2 emissions in a given year (or from the alternative perspective, the benefit to society of reducing CO_2 emissions by one ton). The SCC includes (but is not limited to) climate damages due to changes in net agricultural productivity, human health, property damages from flood risk, and ecosystem services due to climate change. The SCC estimates currently used by the Agency were developed through an interagency process that included EPA and other executive branch entities, and concluded in February 2010. The Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 for the final joint EPA/Department of Transportation Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards provides a complete discussion of the methods used to develop the SCC estimates (Interagency Working Group on Social Cost of Carbon, 2010).

To estimate global social benefits of reduced CO_2 emissions, the interagency group selected four SCC values for use in regulatory analyses: \$6, \$25, \$40, and \$76 per metric ton of CO_2 emissions in 2015, in 2008 dollars. The first three values are based on the average SCC estimated using three integrated assessment models (IAMs), at discount rates of 5.0, 3.0, and 2.5 percent, respectively. When valuing the impacts of climate change, IAMs couple economic and climate systems into a single model to capture important interactions between the components. SCCs estimated using different discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the distribution of SCC estimates from all three models at a 3.0 percent discount rate. It is included to represent higher-than-expected damages from temperature change further out in the tails of the SCC distribution.

[48] US Environmental Protection Agency. Greenhouse Gas Equivalency Calculator available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html accessed 07/19/11.

Although there are relatively few region- or country-specific estimates of SCC in the literature, the results from one model suggest the ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. For example, with a 2.5 or 3 percent discount rate, the U.S. benefit is about 7-10 percent of the global benefit, on average, across the scenarios analyzed. Alternatively, if the fraction of GDP lost due to climate change is assumed to be similar across countries, the domestic benefit would be proportional to the U.S. share of global GDP, which is currently about 23 percent. On the basis of this evidence, values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects. It is recognized that these values are approximate, provisional, and highly speculative. There is no a priori reason why domestic benefits should be a constant fraction of net global damages over time. (Interagency Working Group on Social Cost of Carbon, 2010).

The interagency group noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. The limited amount of research linking climate impacts to economic damages makes estimating damages from climate change even more difficult. The interagency group hopes that over time researchers and modelers will work to fill these gaps and that the SCC estimates used for regulatory analysis by the Federal government will continue to evolve with improvements in modeling. Additional details on these limitations are discussed in the SCC TSD.

A significant limitation of the aforementioned interagency process particularly relevant to this rulemaking is that the social costs of non-CO_2 GHG emissions were not estimated. Specifically, the interagency group did not directly estimate the social cost of non-CO_2 GHGs using the three models. Moreover, the group determined that it would not transform the CO_2 estimates into estimates for non-CO_2 GHGs using global warming potentials (GWPs), which measure the ability of different gases to trap heat in the atmosphere (i.e., radiative forcing per unit of mass) over a particular timeframe relative to CO_2. One potential method for approximating the value of marginal non-CO_2 GHG emission reductions is to convert the reductions to CO_2-equivalents which may then be valued using the SCC. Conversion to CO_2-e is typically done using the GWPs for the non-CO_2 gas. The GWP is an aggregate measure that approximates the additional energy trapped in the atmosphere over a given timeframe from a perturbation of a non-CO_2 gas relative to CO_2. The time horizon most commonly used is 100 years. One potential problem with utilizing temporally aggregated statistics, such as the GWPs, is that the additional radiative forcing from the GHG perturbation is not constant over time and any differences in temporal dynamics between gases will be lost. This is a potentially confounding issue given that the social cost of GHGs is based on a discounted stream of damages that are non-linear in temperature. For example, methane has an expected adjusted atmospheric lifetime of about 12 years and associated GWP of 21 (IPCC Second Assessment Report (SAR) 100-year GWP estimate). Gases with a shorter lifetime, such as methane, have impacts that occur primarily in the near term and thus are not discounted as heavily as those caused by the longer-lived gases, while the GWP treats additional forcing the same independent of when it occurs in time. Furthermore, the baseline temperature change is lower in the near term and therefore the additional warming from relatively short lived gases will have a lower marginal impact relative to longer lived gases that have an impact further out in the future when baseline warming is higher. The GWP also relies on an arbitrary time horizon and constant concentration scenario. Both of which are inconsistent with the assumptions used by the SCC interagency workgroup. Finally, impacts other than temperature change also vary across gases in ways that are not captured by GWP. For instance, CO_2 emissions, unlike methane will result in CO_2 passive fertilization to plants.

In light of these limitations, and the significant contributions of non-CO_2 emissions to climate change, further analysis is required to link non-CO_2 emissions to economic impacts and to develop social cost estimates for methane specifically. Such work would feed into efforts to develop a monetized value of reductions in methane greenhouse gas emissions in assessing the co-benefits of this rulemaking. As part of ongoing work to further improve the SCC estimates, the interagency group hopes to develop methods to value greenhouse gases other than CO_2, such as methane, by the time SCC estimates for CO_2 emissions are revised.

The EPA recognizes that the methane reductions proposed in this rule will provide significant economic climate co-benefits to society. However, EPA finds itself in the position of having no interagency accepted monetary values to place on these co-benefits. The 'GWP approach' of converting methane to CO_2-e using the GWP of methane, as previously described, is one approximation method for estimating the monetized value of the methane reductions anticipated from this rule. This calculation uses the GWP of the non-CO_2 gas to estimate CO_2 equivalents and then multiplies these CO_2 equivalent emission reductions by the SCC to generate monetized estimates of the co-benefits. If one makes these calculations for the proposed Option 2 (including expected methane emission reductions from the NESHAP amendments and NSPS and considers secondary impacts) of the oil and gas rule, the 2015 co-benefits vary by discount rate and range from about $373 million to over $4.7 billion; the SCC at the 3 percent discount rate ($25 per metric ton) results in an estimate of $1.6 billion in 2015. These co-benefits equate to a range of approximately $110 to $1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of $480 at the 3 percent discount rate

As previously stated, these co-benefit estimates are not the same as would be derived using a directly computed social cost of methane (using the integrated assessment models employed to develop the SCC estimates) for a variety of reasons including the shorter atmospheric lifetime of methane relative to CO_2 (about 12 years compared to CO_2 whose concentrations in the atmosphere decay on timescales of decades to millennia). The climate impacts also differ between the pollutants for reasons other than the radiative forcing profiles and atmospheric lifetimes of these gases. Methane is a precursor to ozone and ozone is a short-lived climate forcer as previously discussed. This use of the SAR GWP to approximate benefits may underestimate the direct radiative forcing benefits of reduced ozone levels, and does not capture any secondary climate co-benefits involved with ozone-ecosystem interactions. In addition, a recent NCEE working paper suggests that this quick 'GWP approach' to benefits estimation will likely understate the climate benefits of methane reductions in most cases (Marten and Newbold, 2011). This conclusion is reached using the 100 year GWP for methane of 25 as put forth in the IPCC Fourth Assessment Report as opposed to the lower value of 21 used in this analysis. Using the higher GWP estimate of 25 would increase these reported methane climate co-benefit estimates by about 19 percent. Although the IPCC Fourth Assessment Report suggested a GWP of 25, EPA has used GWP of 21 consistent with the IPCC SAR to estimate the methane climate co-benefits for this oil and gas proposal. The use of the SAR GWP values allows comparability of data collected in this proposed rule to the national GHG inventory that EPA compiles annually to meet U.S. commitments to the United Nations Framework Convention on Climate Change (UNFCCC). To comply with international reporting standards under the UNFCCC, official emission estimates are to be reported by the U.S. and other countries using SAR GWP values. The UNFCCC reporting guidelines for national inventories were updated in 2002 but continue to require the use of GWPs from the SAR. The parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon although other time horizon values are available. The SAR GWP value for methane is also currently used to establish GHG reporting requirements as mandated by the GHG Reporting Rule (2010e) and is used by the EPA to determine Title V and Prevention of Significant Deterioration GHG permitting requirements as modified by the GHG Tailoring Rule (2010f).

EPA also undertook a literature search for estimates of the marginal social cost of methane. A range of marginal social cost of methane benefit estimates are available in published literature (Fankhauser (1994), Kandlikar (1995), Hammitt et al. (1996), Tol et al. (2003), Tol, et al. (2006), Hope (2005) and Hope and Newberry (2006). Most of these estimates are based upon modeling assumptions that are dated and inconsistent with the current SCC estimates. Some of these studies focused on marginal methane reductions in the 1990s and early 2000s and report estimates for only the single year of interest specific to the study. The assumptions underlying the social cost of methane estimates available in the literature differ from those agreed upon by the SCC interagency group and in many cases use older versions of the IAMs. Without additional analysis, the methane climate benefit estimates available in the current literature are not acceptable to use to value the methane reductions proposed in this rulemaking.

Due to the uncertainties involved with 'GWP approach' estimates presented and estimates available in the literature, EPA chooses not to compare these co-benefit estimates to the costs of the rule for this proposal. Rather, the EPA presents the 'GWP approach' climate co-benefit estimates as an interim method to produce lower-bound estimates until the interagency group develops values for non-CO_2 GHGs. EPA requests comments from interested parties and the public about this interim approach specifically and more broadly about appropriate methods to monetize the climate co-benefits of methane reductions. In particular, EPA seeks public comments to this proposed rulemaking regarding social cost of methane estimates that may be used to value the co-benefits of methane emission reductions anticipated for the oil and gas industry from this rule. Comments specific to whether GWP is an acceptable method for generating a placeholder value for the social cost of methane until interagency modeled estimates become available are welcome. Public comments may be provided in the official docket for this proposed rulemaking in accordance with the process outlined in the preamble for the rule. These comments will be considered in developing the final rule for this rulemaking.

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5 STATUTORY AND EXECUTIVE ORDER REVIEWS

5.1 Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 5-1 shows the results of the cost and benefits analysis for these proposed rules.

Table 5-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS and NESHAP Amendments in 2015 (millions of 2008$)[1]

	Proposed NSPS	Proposed NESHAP Amendments	Proposed NSPS and NESHAP Amendments Combined
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$45 million	$16 million	-$29 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	37,000 tons of HAPs	1,400 tons of HAPs	38,000 tons of HAPs
	540,000 tons of VOCs	9,200 tons of VOCs	540,000 tons of VOCs
	3.4 million tons of methane	4,900 tons of methane	3.4 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

5.2 Paperwork Reduction Act

The information collection requirements in this proposed action have been submitted for approval to OMB under the PRA, 44 U.S.C. 3501, et seq. The ICR document prepared by the EPA has been assigned EPA ICR Numbers 1716.07 (40 CFR part 60, subpart OOOO), 1788.10 (40 CFR part 63, subpart HH), 1789.07 (40 CFR part 63, subpart HHH), and 1086.10 (40 CFR part 60, subparts KKK and subpart LLL).

The information to be collected for the proposed NSPS and the proposed NESHAP amendments are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

These proposed rules would require maintenance inspections of the control devices, but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

For sources subject to the proposed NSPS, the burden represents labor hours and costs associated from annual reporting and recordkeeping for each affected facility. The estimated burden is based on the annual expected number of affected operators for the first three years following the effective date of the standards. The burden is estimated to be 560,000 labor hours at a cost of around$18 million per year. This includes the labor and cost estimates previously estimated for sources subject to 40 CFR part 60, subpart KKK and subpart LLL (which is being incorporated into 40 CFR part 60, subpart OOOO). The average hours and cost per regulated entity, which is assumed to be on a per operator basis except for natural gas processing plants (which are estimated on a per facility basis) subject to the NSPS for oil and natural gas production and natural gas transmissions and distribution facilities would be 110 hours per response and $3,693 per response based on an average of 1,459 operators responding per year and 16 responses per year. The majority of responses are expected to be notifications of construction. One annual report is required that may include all affected facilities owned per each operator. Burden by for the proposed NSPS was based on EPA ICR Number 1716.07.

The estimated recordkeeping and reporting burden after the effective date of the proposed amendments is estimated for all affected major and area sources subject to the oil and natural gas production NESHAP (40 CFR 63, subpart HH) to be approximately 63,000 labor hours per year at a cost of $2.1 million per year. For the natural gas transmission and storage NESHAP, the recordkeeping and reporting burden is estimated to be 2,500 labor hours per year at a cost of $86,800 per year. This estimate includes the cost of reporting, including reading instructions, and information gathering. Recordkeeping cost estimates include reading instructions, planning activities, and conducting compliance monitoring. The average hours and cost per regulated entity subject to the oil and natural gas production NESHAP would be 72 hours per year and $2,500 per year based on an average of 846 facilities per year and three responses per facility. For the natural gas transmission and storage NESHAP, the average hours and cost per regulated entity would be 50 hours per year and $1,600 per year based on an average of 53 facilities per year and three responses per facility. Burden is defined at 5 CFR 1320.3(b). Burden for the oil and natural gas production NESHAP is estimated under EPA ICR Number 1788.10. Burden for the natural gas transmission and storage NESHAP is estimated under EPA ICR Number 1789.07.

5.3 Regulatory Flexibility Act

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) a small business whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

5.3.1 Proposed NSPS

After considering the economic impact of the Proposed NSPS on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities (SISNOSE). EPA performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. Based upon the analysis in Section 7.4 in this RIA, EPA recognizes that a subset of small firms is likely to be significantly impacted by the proposed NSPS. However, the number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that the firm-level compliance cost estimates used in the small business impacts analysis are likely over-estimates of the compliance costs faced by firms under the Proposed NSPS; these estimates do not include the revenues that producers are expected receive from the additional natural gas recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from well completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated, if not fully offset. Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities by the selection of highly cost-effective controls and specifying monitoring requirements that are the minimum to insure compliance.

5.3.2 Proposed NESHAP Amendments

After considering the economic impact of the Proposed NESHAP Amendments on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Based upon the analysis in Section 7.4 in this RIA, we estimate that 62 of the 118 firms (53 percent) that own potentially affected facilities are small entities. EPA performed a screening analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile 10 firms (16 percent) are likely to have impacts greater than 1 percent. Four of these 10 firms are likely to have impacts greater than 3 percent. While these 10 firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211. Although this final rule will not impact a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities by setting the final emissions limits at the MACT floor, the least stringent level allowed by law.

5.4 Unfunded Mandates Reform Act

This proposed rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any one year. Thus, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments nor does it impose obligations upon them.

5.5 Executive Order 13132: Federalism

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this proposed rule.

5.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. The EPA has concluded that this proposed rule will not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effect on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

5.7 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This proposed rule is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is economically significant as defined in Executive Order 12866. However, EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action would not relax the control measures on existing regulated sources. EPA's risk assessments (included in the docket for this proposed rule) demonstrate that the existing regulations are associated with an acceptable level of risk and provide an ample margin of safety to protect public health.

5.8 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211, (66 FR 28,355, May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: 1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or 2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action."

The proposed rules will result in the addition of control equipment and monitoring systems for existing and new sources within the oil and natural gas industry. The proposed NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed NESHAP amendments are not "significant energy actions" as defined in Executive Order 13211, (66 FR 28355, May 22, 2001).

The proposed NSPS is also unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed NSPS is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001). The basis for the determination is as follows.

We use the NEMS to estimate the impacts of the proposed NSPS on the United States energy system. The NEMS is a publically available model of the United States energy economy developed and maintained by the Energy Information Administration of the U.S. DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

Proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One pollution control requirement of the proposed NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the proposed NSPS.

The analysis of energy impacts for the proposed NSPS that includes the additional product recovery shows that domestic natural gas production is estimated to increase (20 billion cubic feet or 0.1 percent) and natural gas prices to decrease ($0.04/Mcf or 0.9 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. Domestic crude oil production is not estimated to change, while crude oil prices are estimated to decrease slightly ($0.02/barrel or less than 0.1 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. All prices are in 2008 dollars.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden.

5.9 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law No. 104-113 (15 U.S.C. 272 note) directs the EPA to use VCS in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the requirements of the NTTAA apply to this action. We are proposing to revise 40 CFR part 63, subparts HH and HHH to allow ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses (Part 10, Instruments and Apparatus) to be used in lieu of EPA Methods 3B, 6 and 16A. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990. Also, we are proposing to revise 40 CFR part 63, subpart HHH, to allow ASTM D6420-99(2004), "Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry" to be used in lieu of EPA Method 18. For a detailed discussion of this VCS, and its appropriateness as a substitute for Method 18, see the final oil and natural gas production NESHAP (Area Sources) (72 FR 36, January 3, 2007).

As a result, the EPA is proposing ASTM D6420-99 for use in 40 CFR part 63, subpart HHH. The EPA also proposes to allow Method 18 as an option in addition to ASTM D6420-99(2004). This would allow the continued use of GC configurations other than GC/MS.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

5.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on Environmental Justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

To examine the potential for any EJ issues that might be associated with each source category, we evaluated the distributions of HAP-related cancer and noncancer risks across different social, demographic, and economic groups within the populations living near the facilities where these source categories are located. The methods used to conduct demographic analyses for this rule are described in section VII.D of the preamble for this rule. The development of demographic analyses to inform the consideration of EJ issues in EPA rulemakings is an evolving science. The EPA offers the demographic analyses in this proposed rulemaking as examples of how such analyses might be developed to inform such consideration, and invites public comment on the approaches used and the interpretations made from the results, with the hope that this will support the refinement and improve utility of such analyses for future rulemakings.

For the demographic analyses, we focused on the populations within 50 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater, or noncancer HI of 1 or greater (based on the emissions of the source category or the facility, respectively). We examined the distributions of those risks across various demographic groups, comparing the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. The results, including other risk metrics, such as average risks for the exposed populations, are documented in source category-specific technical reports in the docket for both source categories covered in this proposal.

As described in the preamble, our risk assessments demonstrate that the regulations for the oil and natural gas production and natural gas transmission and storage source categories, are associated with an acceptable level of risk and that the proposed additional requirements will provide an ample margin of safety to protect public health.

Our analyses also show that, for these source categories, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic noncancer health impacts are unlikely. The EPA has determined that although there may be an existing disparity in HAP risks from these sources between some demographic groups, no demographic group is exposed to an unacceptable level of risk.

6 COMPARISON OF BENEFITS AND COSTS

Because we are unable to estimate the monetary value of the emissions reductions from the proposed rule, we have chosen to rely upon a break-even analysis to estimate what the monetary value benefits would need to attain in order to equal the costs estimated to be imposed by the rule. A break-even analysis answers the question, "What would the benefits need to be for the benefits to exceed the costs." While a break-even approach is not equivalent to a benefits analysis or even a net benefits analysis, we feel the results are illustrative, particularly in the context of previously modeled benefits.

The total cost of the proposed NSPS in the analysis year of 2015 when the additional natural gas and condensate recovery is included in the analysis is estimated at -$45 million for domestic producers and consumers. EPA anticipates that this rule would prevent 540,000 tons of VOC, 3.4 million tons of methane, and 37,000 tons of HAPs in 2015 from new sources. In 2015, EPA estimates the costs for the NESHAP amendments floor option to be $16 million.[49] EPA anticipates that this rule would reduce 9,200 tons of VOC, 4,900 tons of methane, and 1,400 tons of HAPs in 2015 from existing sources. For the NESHAP amendments, a break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health benefits, and ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

For the proposed NSPS, the revenue from additional natural gas recovery already exceeds the costs, which renders a break-even analysis unnecessary. However, as discussed in Section 3.2.2., estimates of the annualized engineering costs that include revenues from natural gas product recovery depend heavily upon assumptions about the price of natural gas and hydrocarbon condensates in analysis year 2015. Therefore, we have also conducted a break-even analysis for the price of natural gas. For the NSPS, a break-even analysis suggests that the price

[49] See Section 3 of this RIA for more information regarding the cost estimates for the NESHAP.

of natural gas would need to be at least $3.77 per Mcf in 2015 for the revenue from product recovery to exceed the annualized costs. EIA forecasts that the price of natural gas would be $4.26 per Mcf in 2015. In addition to the revenue from product recovery, the NSPS would avert emissions of VOCs, HAPs, and methane, which all have value that could be incorporated into the break-even analysis. Figure 6-1 illustrates one method of analyzing the break-even point with alternate natural gas prices and VOC benefits. If, as an illustrative example, the price of natural gas was only $3.00 per Mcf, VOCs would need to be valued at $260 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

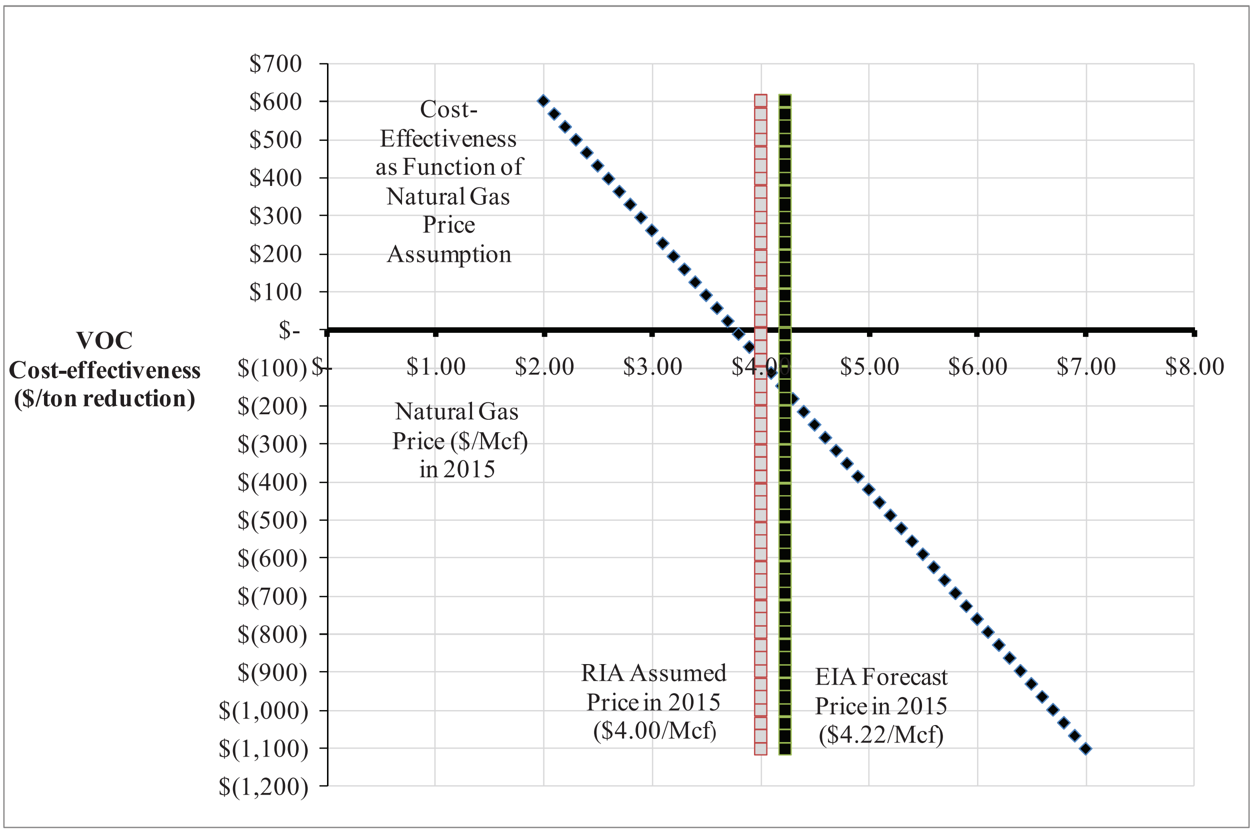

Figure 6-1 Illustrative Break-Even Diagram for Alternate Natural Gas Prices for the NSPS

With the data available, we are not able to provide a credible benefit-per-ton estimate for any of the pollutant reductions for these rules to compare to the break-even estimates. Based on the methodology from Fann, Fulcher, and Hubbell (2009), average $PM_{2.5}$ health-related benefits of VOC emissions are valued at $280 to $7,000 per ton across a range of eight urban areas.[50] In addition, ozone benefits have been previously valued at $240 to $1,000 per ton of VOC reduced. Using the GWP approach, the climate co-benefits range from approximately $110 to $1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of $760 at the 3 percent discount rate.

These break-even benefit-per-ton estimates assume that all other pollutants have zero value. Of course, it is inappropriate to assume that the value of reducing any of these pollutants is zero. Thus, the real break-even estimate is actually lower than the estimates provided above because the other pollutants each have non-zero benefits that should be considered. Furthermore, a single pollutant can have multiple effects (e.g., VOCs contribute to both ozone and $PM_{2.5}$ formation that each have health and welfare effects) that would need to be summed in order to develop a comprehensive estimate of the monetized benefits associated with reducing that pollutant.

As previously described, the revenue from additional natural gas recovery already exceeds the costs of the NSPS, but even if the price of natural gas was only $3.00 per Mcf, it is likely that the VOC benefits would exceed the costs, As a result, even if VOC emissions from oil and natural gas operations result in monetized benefits that are substantially below the average modeled benefits, there is a reasonable chance that the benefits of these rules would exceed the costs, especially if we were able to monetize all of the benefits associated with ozone formation, visibility, HAPs, and methane.

Table 6-1 and Table 6-2 present the summary of the benefits, costs, and net benefits for the NSPS and NESHAP amendment options, respectively. Table 6-3 provides a summary of the direct and secondary emissions changes for each option.

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[50] See Section 4.5 of this RIA for more information regarding $PM_{2.5}$ benefits and Section 4.6 for more information regarding ozone benefits.

Table 6-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS in 2015 (millions of 2008$)[1]

	Option 1: Alternative	Option 2: Proposed[4]	Option 3: Alternative
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$19 million	-$45 million	$77 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	17,000 tons of HAPs[5]	37,000 tons of HAPs[5]	37,000 tons of HAPs[5]
	270,000 tons of VOCs	540,000 tons of VOCs	550,000 tons of VOCs
	1.6 million tons of methane	3.4 million tons of methane	3.4 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

Table 6-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP amendments in 2015 (millions of 2008$)[1]

	Option 1: Proposed (Floor)
Total Monetized Benefits[2]	N/A
Total Costs[3]	$16 million
Net Benefits	N/A
Non-monetized Benefits	1,400 tons of HAPs
	9,200 tons of VOCs[4]
	4,900 tons of methane[4]
	Health effects of HAP exposure
	Health effects of $PM_{2.5}$ and ozone exposure[4]
	Visibility impairment[4]
	Vegetation effects[4]
	Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NESHAP are anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.

[3] The cost estimates are assumed to be equivalent to the engineering cost estimates. The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

Table 6-3 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP
Change in Direct Emissions	VOC	-270,000	-540,000	-550,000	-9,200
	Methane	-1,600,000	-3,400,000	-3,400,000	-4,900
	HAP	-17,000	-37,000	-37,000	-1,400
Change in Secondary Emissions (Producer-Side) [1]	CO_2	990,000	990,000	990,000	5,500
	NOx	510	510	510	2.9
	PM	7.6	7.6	7.6	0.1
	CO	2,800	2,800	2,800	16
	THC	1,000	1,000	1,000	6.0
Change in Secondary Emissions (Consumer-Side)	CO_2-e	-1,000,000	1,700,000	1,400,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e	-33,000,000	-68,000,000	-70,000,000	-96,000

[1] We use the producer-side secondary impacts associated with the proposed NSPS option as a surrogate for the impacts of the other options.

7 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

7.1 Introduction

This section includes three sets of analyses for both the NSPS and NESHAP amendments:

- Energy System Impacts
- Employment Impacts
- Small Business Impacts Analysis

7.2 Energy System Impacts Analysis of Proposed NSPS

We use the National Energy Modeling System (NEMS) to estimate the impacts of the proposed NSPS on the U.S. energy system. The impacts we estimate include changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas. We evaluate whether and to what extent the increased production costs imposed by the NSPS might alter the mix of fuels consumed at a national level. With this information we estimate how the changed fuel mix affects national level CO_2-equivalent greenhouse gas emissions from energy sources. We additionally combine these estimates of changes in CO_2-equivalent greenhouse gas emissions from energy sources and emissions co-reductions of methane from the engineering analysis with NEMS analysis to estimate the net change in CO_2-equivalent greenhouse gas emissions from energy-related sources, but this analysis is reserved for the secondary environmental impacts analysis within Section 4.

A brief conceptual discussion about our energy system impacts modeling approach is necessary before going into detail on NEMS, how we implemented the regulatory impacts, and results. Economically, it is possible to view the recovered natural gas as an explicit output or as contributing to an efficiency gain at the producer level. For example, the analysis for the proposed NSPS shows that about 97 percent of the natural gas captured by emissions controls suggested by the rule is captured by performing RECs on new and existing wells that are completed after being hydraulically fractured. The assumed $4/Mcf price for natural gas is the price paid to producers at the wellhead. In the natural gas industry, production is metered at or very near to the wellhead, and producers are paid based upon this metered production. Depending on the situation, the gas captured by RECs is sent through a temporary or permanent meter. Payments for the gas are typically made within 30 days.

To preview the energy systems modeling using NEMS, results show that after economic adjustments to the new regulations are made by producers, the captured natural gas represents both increased output (a slight increment in aggregate production) and increased efficiency (producing slightly more for less). However, because of differing objectives for the regulatory analysis we treat the associated savings differently in the engineering cost analysis (as an explicit output) and in NEMS (as an efficiency gain).

In the engineering cost analysis, it is necessary to estimate the expected costs and revenues from implementing emissions controls at the unit level. Because of this, we estimate the net costs as expected costs minus expected revenues for representative units. On the other hand, NEMS models the profit maximizing behavior of representative project developers at a drilling project level. The net costs of the regulation alter the expected discounted cash flow of drilling and implementing oil and gas projects, and the behavior of the representative drillers adjusts accordingly. While in the regulatory case natural gas drilling has become more efficient because of the gas recovery, project developers still interact with markets for which supply and demand are simultaneously adjusting. Consequently, project development adjusts to a new equilibrium. While we believe the cost savings as measured by revenues from selling recovered gas (engineering costs) and measured by cost savings from averted production through efficiency gains (energy economic modeling) are approximately the same, it is important to note that the engineering cost analysis and the national-level cost estimates do not incorporate economic feedbacks such as supply and demand adjustments.

7.2.1 Description of the Department of Energy National Energy Modeling System

NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration of the U.S. Department of Energy. NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy economy from the current year to 2035. DOE first developed NEMS in the 1980s, and the model has been undergone frequent updates and expansion since. DOE uses the modeling system extensively to produce issue reports, legislative analyses, and respond to Congressional inquiries.

EIA is legally required to make the NEMS system source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of the NEMS model, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues.

NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions. The dynamics of the energy system are governed by assumptions about energy and environmental policies, technological developments, resource supplies, demography, and macroeconomic conditions. An overview of the model and complete documentation of NEMS can be found at <http://www.eia.doe.gov/oiaf/aeo/overview/index.html>.

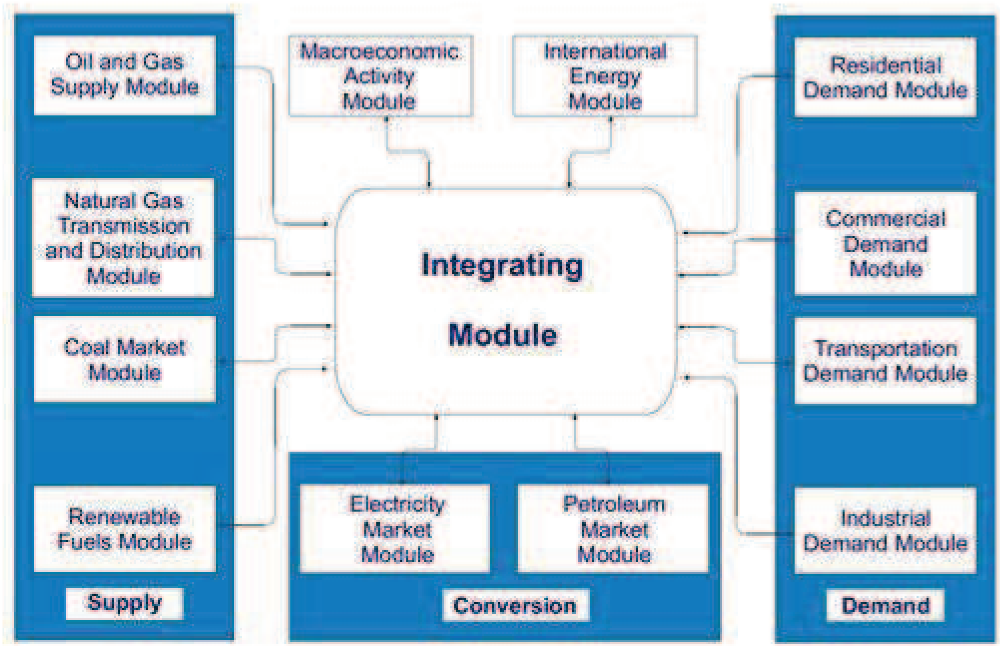

Figure 7-1 Organization of NEMS Modules (source: U.S. Energy Information Administration)

NEMS is a large-scale, deterministic mathematical programming model. NEMS iteratively solves multiple models, linear and non-linear, using nonlinear Gauss-Seidel methods (Gabriel et al. 2001). What this means is that NEMS solves a single module, holding all else constant at provisional solutions, then moves to the next model after establishing an updated provisional solution.

NEMS provides what EIA refers to as "mid-term" projections to the year 2035. However, as this RIA is concerned with estimating regulatory impacts in the first year of full implementation, our analysis focuses upon estimated impacts in the year 2015, with regulatory costs first imposed in 2011. For this RIA, we draw upon the same assumptions and model used in the Annual Energy Outlook 2011.[51] The RIA baseline is consistent with that of the Annual Energy Outlook 2011 which is used extensively in Section 2 in the Industry Profile.

[51] Assumptions for the 2011 Annual Energy Outlook can be found at <http://www.eia.gov/forecasts/aeo/assumptions/index.cfm>.

7.2.2 Inputs to National Energy Modeling System

To model potential impacts associated with the NSPS, we modified oil and gas production costs within the Oil and Gas Supply Module (OGSM) of NEMS and domestic and Canadian natural gas production within the Natural Gas Transmission and Distribution Module (NGTDM). The OGSM projects domestic oil and gas production from onshore, offshore, Alaskan wells, as well as having a smaller-scale treatment of Canadian oil and gas production (U.S. EIA, 2010). The treatment of oil and gas resources is detailed in that oil, shale oil, conventional gas, shale gas, tight sands gas, and coalbed methane (CBM) are explicitly modeled. New exploration and development is pursued in the OGSM if the expected net present value of extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern finding and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the Oil and Natural Gas NSPS. We are able to target additional expenditures for environmental controls expected to be required by the NSPS on new exploratory and developmental oil and gas production activities, as well as add additional costs to existing projects. We model the impacts of additional environmental costs, as well as the impacts of additional product recovery. We explicitly model the additional natural gas recovered when implementing the NSPS regulatory options. However, we are unable to explicitly model the additional production of condensates expected to be recovered by reduced emissions completions, although we incorporate expected revenues from the condensate recovery in the economic evaluation of new drilling projects.

While the oil production simulated by the OGSM is sent to the refining module (the Petroleum Market Module), simulated natural gas production is sent to a transmission and distribution network captured in the NGTDM. The NGTDM balances gas supplies and prices and “negotiates” supply and consumption to determine a regional equilibrium between supply, demand and prices, including imports and exports via pipeline or LNG. Natural gas transmitted through a simplified arc-node representation of pipeline infrastructure based upon pipeline economics.

7.2.2.1 *Compliance Costs for Oil and Gas Exploration and Production*

As the NSPS affects new emissions sources, we chose to estimate impacts on new exploration and development projects by adding costs of environmental regulation to the algorithm that evaluates the profitability of new projects. Additional NSPS costs associated with reduced emission completions and future recompletions for new wells are added to drilling, completion, and stimulation costs, as these are, in effect, associated with activities that occur within a single time period, although they may be repeated periodically, as in the case of recompletions. Costs required for reduced emissions recompletions on existing wells are added to stimulation expenses for existing wells exclusively. Other costs are operations and maintenance-type costs and are added to fixed operation and maintenance (O&M) expenses associated with new projects. The one-shot and continuing O&M expenses are estimated and entered on a per well basis, depending on whether the costs would apply to oil wells, natural gas wells, both oil and natural gas wells, or a subset of either. We base the per well cost estimates on the engineering costs including revenues from additional product recovery. This approach is appropriate given the structure of the NEMS algorithm that estimates the net present value of drilling projects.

One concern in basing the regulatory costs inputs into NEMS on the net cost of the compliance activity (estimated annualized cost of compliance minus estimated revenue from product recovery) is that potential barriers to obtaining capital may not be adequately incorporated in the model. However, in general, potential barriers to obtaining additional capital should be reflected in the annualized cost via these barriers increasing the cost of capital. With this in mind, assuming the estimates of capital costs and product recovery are valid, the NEMS results will reflect barriers to obtaining the retired capital. A caveat to this is that the estimated unit-level capital costs of controls which are newly required at a national-level as a result of the proposed regulation—RECs, for example—may not incorporate potential additional transitional costs as the supply of control equipment adjusts to new demand.

Table 7-1 shows the incremental O&M expenses that accrue to new drilling projects as a result of producers having to comply with the relevant NSPS option. We estimate those costs as a function of new wells expected to be drilled in a representative year. To arrive at estimates of the per well costs, we first identify which emissions reductions will apply primarily to crude oil wells, to natural gas wells, or to both crude oil and natural gas wells. Based on the baseline projections of successful completions in 2015, we used 19,097 new natural gas wells and 12,193 new oil wells as the basis of these calculations. We then divide the estimated compliance costs for the given emissions point (from Table 3-3) by the appropriate number of expected new wells in the year of analysis. The result yields an approximation of a per well compliance costs. We assume this approximation is representative of the incremental cost faced by a producer when evaluating a prospective drilling project.

Like the engineering analysis, we assume that hydraulically fractured well completions and recompletions will be required of wells drilled into tight sand, shale gas, and coalbed methane formations. While costs for well recompletions reflect the cost of a single recompletion, the engineering cost analysis assumed that one in ten new wells drilled after the implementation of the promulgation and implementation of the NSPS are completed using hydraulic fracturing will receive a recompletion in any given year using hydraulic fracturing. Meanwhile, within NEMS, wells are assumed to be stimulated every five years. We assume these more frequent stimulations are less intensive than stimulation using hydraulic fracturing but add costs such that the recompletions costs reflect the same assumptions as the engineering analysis. In entering compliance costs into NEMS, we also account for reduced emissions completions, completion combustion, and recompletions performed in absence of the regulation, using the same assumptions as the engineering costs analysis (Table 7-2).

Table 7-1 Summary of Additional Annualized O&M Costs (on a Per New Well Basis) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Well Costs (2008$) Option 1	Option 2 (Proposed)	Option 3	Wells Applied To in NEMS
Equipment Leaks					
Well Pads	Subpart VV	Not in Option	Not in Option	$3,552	Oil and Gas
Gathering and Boosting Stations	Subpart VV	Not in Option	Not in Option	$806	Gas
Processing Plants	Subpart VVa	Not in Option	$56	$56	None
Transmission Compressor Stations	Subpart VV	Not in Option	Not in Option	$320	Gas
Reciprocating Compressors					
Well Pads	Annual Monitoring/ Maintenance	Not in Option	Not in Option	Not in Option	None
Gathering/Boosting Stations	AMM	$17	$17	$17	Gas
Processing Plants	AMM	$12	$12	$12	Gas
Transmission Compressor Stations	AMM	$19	$19	$19	Gas
Underground Storage Facilities	AMM	$1	$1	$1	Gas
Centrifugal Compressors					
Processing Plants	Dry Seals/Route to Process or Control	-$113	-$113	-$113	Gas
Transmission Compressor Stations	Dry Seals/Route to Process or Control	-$62	-$62	-$62	Gas
Pneumatic Controllers -					
Oil and Gas Production	Low Bleed/Route to Process	-$698	-$698	-$698	Oil and Gas
Natural Gas Transmission and Storage	Low Bleed/Route to Process	$0.10	$0.10	$0.10	Gas
Storage Vessels					
High Throughput	95% control	$143	$143	$143	Oil and Gas
Low Throughput	95% control	Not in Option	Not in Option	Not in Option	None

Table 7-2 Summary of Additional Per Completion/Recompletion Costs (2008$) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Completion/Recompletion Costs (2008$) Option 1	Option 2 (proposed)	Option 3	Wells Applied To in NEMS
Well Completions					
Hydraulically Fractured Gas Wells	REC	-$1,275	-$1,275	-$1,275	New Tight Sand/ Shale Gas/CBM
Conventional Gas Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Oil Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Well Recompletions					
Hydraulically Fractured Gas Wells (post-NSPS wells)	REC	-$1,535	-$1,535	-$1,535	Existing Tight Sand/ Shale Gas /Coalbed Methane
Hydraulically Fractured Gas Wells (existing wells)	REC	Not in Option	-$1,535	-$1,535	Existing Tight Sand/ Shale Gas /Coalbed Methane
Conventional Gas Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Oil Wells	Combustion	Not in Option	Not in Option	Not in Option	None

7.2.2.2 Adding Averted Methane Emissions into Natural Gas Production

A significant benefit of controlling VOC emissions from oil and natural gas production is that methane that would otherwise be lost to the atmosphere can be directed into the natural gas production stream. We chose to model methane capture in NEMS as an increase in natural gas industry productivity, ensuring that, within the model, natural gas reservoirs are not decremented by production gains from methane capture. We add estimates of the quantities of methane captured (or otherwise not vented or combusted) to the base quantities that the OGSM model supplies to the NGTDM model. We subdivide the estimates of commercially valuable averted emissions by region and well type in order to more accurately portray the economics of implementing the environmental technology. Adding the averted methane emissions in this manner has the effect of moving the natural gas supply curve to the right an increment consistent with the technically achievable emissions transferred into the production stream as a result of the proposed NSPS.

For all control options, with the exception of recompletions on existing wells, we enter the increased natural gas recovery into NEMS on a per-well basis for new wells, following an estimation procedure similar to that of entering compliance costs into NEMS on a per well basis for new wells. Because each NSPS Option is composed of a different suite of emissions controls, the per-well natural gas recovery value for new wells is different across wells. For Option 1, we estimate that natural gas recovery is 5,739 Mcf per well. For Option 2 and Option 3, we estimate that natural gas recovery is 5,743 Mcf per well. We make a simplifying assumption that natural gas recovery accruing to new wells accrues to new wells in shale gas, tight sands, and CBM fields. We make these assumptions because new wells in these fields are more likely to satisfy criteria such that RECs are required, which contributed that large majority of potential natural gas recovery. Note that these per well natural gas recovery is lower than the per well estimate when RECs are implemented. The estimate is lower because we account for emissions that are combusted, RECs that are implemented absent Federal regulation, as well as the likelihood that natural gas is used during processing and transmission or reinjected.

We treat the potential natural gas recovery associated with recompletions of existing wells (in proposed Option 2 and Option 3) differently in that we estimated the natural gas recovery by natural gas resource type and NSPS Option based on a combination of the engineering analysis and production patterns from the 2011 Annual Energy Outlook. We estimate that additional natural gas product recovered by recompleting existing wells in proposed Option 2 and Option 3 to be 78.7 bcf, with 38.4 bcf accruing to shale gas, 31.4 bcf accruing to tight sands, and 8.9 bcf accruing to CBM, respectively. This quantity is distributed within the NGTDM to reflect regional production by resource type.

7.2.2.3 Fixing Canadian Drilling Costs to Baseline Path

Domestic drilling costs serve as a proxy for Canadian drilling costs in the Canadian oil and natural gas sub-model within the NGTDM. This implies that, without additional modification, additional costs imposed by a U.S. regulation will also impact drilling decisions in Canada. Changes in international oil and gas trade are important in the analysis, as a large majority of natural gas imported into the U.S. originates in Canada. To avoid this problem, we fixed Canadian drilling costs using U.S. drilling costs from the baseline scenario. This solution enables a more accurate analysis of U.S.-Canada energy trade, as increased drilling costs in the U.S. as a result of environmental regulation serve to increase Canada's comparative advantage.

7.2.3 Energy System Impacts

As mentioned earlier, we estimate impacts to drilling activity, reserves, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas, as well as whether and to what extent the NSPS might alter the mix of fuels consumed at a national level. In each of these estimates, we present estimates for the baseline year of 2015 and results for the three NSPS options. For context, we provide estimates of production activities in 2011.

7.2.3.1 Impacts on Drilling Activities

Because the potential costs of the NSPS options are concentrated in production activities, we first report estimates of impacts on crude oil and natural gas drilling activities and production and price changes at the wellhead. Table 7-3 presents estimates of successful wells drilled in the U.S. in 2015, the analysis year, for the three NSPS options and in the baseline.

Table 7-3 Successful Oil and Gas Wells Drilled, NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Successful Wells Drilled					
Natural Gas	16,373	19,097	19,191	18,935	18,872
Crude Oil	10,352	11,025	11,025	11,025	11,028
Total	**26,725**	**30,122**	**30,216**	**29,960**	**29,900**
% Change in Successful Wells Drilled from Baseline					
Natural Gas			0.49%	-0.85%	-1.18%
Crude Oil			0.00%	0.00%	0.03%
Total			**0.31%**	**-0.54%**	**-0.74%**

We estimate that the number of successful natural gas wells drilled increases slightly for Option 1, while the number of successful crude oil wells drilled does not change. In Options 2, where costs of the natural gas processing plants equipment leaks standard and REC requirements for existing wells apply, natural gas wells drilling is forecast to decrease less than 1 percent, while crude oil drilling does not change. For Option 3, where the addition of an additional equipment leak standards add to the incremental costs, natural gas well drilling is estimated to decrease about 1.2%. The number of successful crude oil wells drilled under Option 3 increases very slightly. While it may seem counter-intuitive that the number of successful crude wells increased as costs increase, it is important to note that crude oil and natural gas drilling compete with each other for factors of production, such as labor and material. The environmental compliance costs of the NSPS options predominantly affect natural gas drilling. As natural gas drilling declines, for example, as a result of increased compliance costs, crude oil drilling may increase because of the increased availability of labor and material, as well as the likelihood that crude oil can substitute for natural gas to some extent.

Table 7-4 presents the forecast of successful wells by well type, for onshore drilling in the lower 48 states. The results show that conventional well drilling is unaffected by the regulatory options, as reduced emission completion and completion combustion requirements are directed not toward wells in conventional reserves but toward wells that are hydraulically fractured, the wells in so-called unconventional reserves. The impacts on drilling tight sands, shale gas, and coalbed methane vary by option.

Table 7-4 Successful Wells Drilled by Well Type (Onshore, Lower 48 States), NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Successful Wells Drilled					
Conventional Gas Wells	7,267	7,607	7,607	7,607	7,607
Tight Sands	2,441	2,772	2,791	2,816	2,780
Shale Gas	5,007	7,022	7,074	6,763	6,771
Coalbed Methane	1,593	1,609	1,632	1,662	1,627
Total	**16,308**	**19,010**	**19,104**	**18,849**	**18,785**
% Change in Successful Wells Drilled from Baseline					
Conventional Gas Wells			0.00%	0.00%	0.00%
Tight Sands			0.70%	1.60%	0.29%
Shale Gas			0.74%	-3.68%	-3.57%
Coalbed Methane			1.44%	3.28%	1.09%
Total			**0.50%**	**-0.85%**	**-1.18%**

Well drilling in tight sands is estimated to increase slightly from the baseline under all three options, 0.70 percent, 1.60 percent, and 0.29% for Options 1, 2, and 3, respectively. Wells in CBM reserves are also estimated to increase from the baseline under all three options, or 1.44 percent, 3.28 percent, and 1.09 percent for Options 1, 2, and 3, respectively. However, drilling in shale gas is forecast to decline from the baseline under Options 2 and 3, by 3.68 percent and 3.57 percent, respectively.

7.2.3.2 Impacts on Production, Prices, and Consumption

Table 7-5 shows estimates of the changes in the domestic production of natural gas and crude oil under the NSPS options, as of 2015. Domestic crude oil production is not forecast to change under any of the three regulatory options, again because impacts on crude oil drilling of the NSPS are expected to be negligible.

Table 7-5 Annual Domestic Natural Gas and Crude Oil Production, NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Domestic Production					
Natural Gas (trillion cubic feet)	21.05	22.43	22.47	22.45	22.44
Crude Oil (million barrels/day)	5.46	5.81	5.81	5.81	5.81
% Change in Domestic Production from Baseline					
Natural Gas			0.18%	0.09%	0.04%
Crude Oil			0.00%	0.00%	0.00%

Natural gas production, on the other hand, increases under all three regulatory options for the NSPS from the baseline. A main driver for these increases is the additional natural gas recovery engendered by the control requirements. Another driver for the increases under Option 1 is the increase in natural gas well drilling. While we showed earlier that natural gas drilling is estimated to decline under Options 2 and 3, the increased natural gas recovery is sufficient to offset the production loss from relatively fewer producing wells.

For the proposed option, the NEMS analysis shown in Table 7-5 estimates a 20 bcf increase in domestic natural gas production. This amount is less than the amount estimated in the engineering analysis to be captured by emissions controls implemented as a result of the proposed NSPS (approximately 180 bcf). This difference is because NEMS models the adjustment of energy markets to the now relatively more efficient natural gas production sector. At the new natural gas supply and demand equilibrium in 2015, the modeling estimates 20 bcf more gas is produced at a relatively lower wellhead price (which will be presented momentarily). However, at the new equilibrium, producers implementing emissions controls still capture and sell approximately 180 bcf of natural gas. For example, as shown in Table 7-4, about 11,200 new unconventional natural gas wells are completed under the proposed NSPS; using assumptions from the engineering cost analysis about RECs required under State regulations and exploratory wells exempted from REC requirements, about 9,000 NSPS-required RECs would be performed on new natural gas well completions, according to the NEMS analysis. This recovered natural gas substitutes for natural gas that would be produced from the ground absent the rule. In effect, then, about 160 bcf of natural gas that would have been extracted and emitted into the atmosphere is left in the formation for future extraction.

As we showed for natural gas drilling, Table 7-6 shows natural gas production from onshore wells in the lower 48 states by type of well, predicted for 2015, the analysis year. Production from conventional natural gas wells and CBM wells are estimated to increase under all NSPS regulatory options. Production from shale gas reserves is estimated to decrease under Options 2 and 3, however, from the baseline projection. Production from tight sands is forecast to decline slightly under Option 1.

Table 7-6 Natural Gas Production by Well Type (Onshore, Lower 48 States), NSPS Options

	2011	Baseline	Future NSPS Scenario, 2015 Option 1	Option 2 (Proposed)	Option 3
Natural Gas Production by Well Type (trillion cubic feet)					
Conventional Gas Wells	4.06	3.74	3.75	3.76	3.76
Tight Sands	5.96	5.89	5.87	6.00	6.00
Shale Gas	5.21	7.20	7.26	7.06	7.06
Coalbed Methane	1.72	1.67	1.69	1.72	1.71
Total	**16.95**	**18.51**	**18.57**	**18.54**	**18.53**
% Change in Natural Gas Production by Well Type from Baseline					
Conventional Gas Wells			0.32%	0.42%	0.48%
Tight Sands			-0.43%	1.82%	1.72%
Shale Gas			0.73%	-1.97%	-1.93%
Coalbed Methane			1.07%	2.86%	2.60%
Total			0.31%	0.16%	0.13%

Note: Totals may not sum due to independent rounding.

Overall, of the regulatory options, the proposed Option 2 is estimated to have the highest natural gas production from onshore wells in the lower 48 states, showing a 1.2% increase over the baseline projection.

Table 7-7 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states, estimated for 2015, the year of analysis. All NSPS options show a decrease in wellhead natural gas and crude oil prices. The decrease in wellhead natural gas price form the baseline is attributable largely to the increased productivity of natural gas wells as a result of capturing a portion of completion emissions (in Options 1, 2, and 3) and in capturing recompletion emissions (in Options 2 and 3).

Table 7-7 Lower 48 Average Natural Gas and Crude Oil Wellhead Price, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Lower 48 Average Wellhead Price					
Natural Gas (2008$ per Mcf)	4.07	4.22	4.18	4.18	4.19
Crude Oil (2008$ per barrel)	83.65	94.60	94.59	94.58	94.58
% Change in Lower 48 Average Wellhead Price from Baseline					
Natural Gas			-0.94%	-0.94%	-0.71%
Crude Oil			-0.01%	-0.02%	-0.02%

Table 7-8 presents estimates of the price of natural gas to final consumers in 2008 dollars per million BTU. The production price decreases estimated across NSPS are largely passed on to consumers but distributed unequally across consuming sectors. Electric power sector consumers of natural gas are estimated to receive the largest price decrease while the transportation and residential sectors are forecast to receive the smallest price decreases.

Table 7-8 Delivered Natural Gas Prices by Sector (2008$ per million BTU), 2015, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Delivered Prices (2008$ per million BTU)					
Residential	10.52	10.35	10.32	10.32	10.33
Commercial	9.26	8.56	8.52	8.53	8.54
Industrial	4.97	5.08	5.05	5.05	5.06
Electric Power	4.81	4.77	4.73	4.74	4.75
Transportation	12.30	12.24	12.20	12.22	12.22
Average	**6.76**	**6.59**	**6.55**	**6.57**	**6.57**
% Change in Delivered Prices from Baseline					
Residential			**-0.29%**	**-0.29%**	**-0.19%**
Commercial			**-0.47%**	**-0.35%**	**-0.23%**
Industrial			**-0.59%**	**-0.59%**	**-0.39%**
Electric Power			**-0.84%**	**-0.63%**	**-0.42%**
Transportation			**-0.33%**	**-0.16%**	**-0.16%**
Average			**-0.60%**	**-0.41%**	**-0.30%**

Final consumption of natural gas is also estimated to increase in 2015 from the baseline under all NSPS options, as is shown on Table 7-9. Like delivered price, the consumption shifts are distributed differently across sectors.

Table 7-9 Natural Gas Consumption by Sector, NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Consumption (trillion cubic feet)					
Residential	4.76	4.81	4.81	4.81	4.81
Commercial	3.22	3.38	3.38	3.38	3.38
Industrial	6.95	8.05	8.06	8.06	8.06
Electric Power	7.00	6.98	7.00	6.98	6.97
Transportation	0.03	0.04	0.04	0.04	0.04
Pipeline Fuel	0.64	0.65	0.65	0.66	0.66
Lease and Plant Fuel	1.27	1.20	1.21	1.21	1.21
Total	**23.86**	**25.11**	**25.15**	**25.14**	**25.13**
% Change in Consumption from Baseline					
Residential			0.00%	0.00%	0.00%
Commercial			0.00%	0.00%	0.00%
Industrial			0.12%	0.12%	0.12%
Electric Power			0.29%	0.00%	-0.14%
Transportation			0.00%	0.00%	0.00%
Pipeline Fuel			0.00%	1.54%	1.54%
Lease and Plant Fuel			0.83%	0.83%	0.83%
Total			**0.16%**	**0.12%**	**0.08%**

Note: Totals may not sum due to independent rounding.

7.2.3.3 Impacts on Imports and National Fuel Mix

The NEMS modeling shows that impacts from all NSPS options are not sufficiently large to affect the trade balance of natural gas. As shown in Table 7-10, estimates of crude oil and natural gas imports do not vary from the baseline in 2015 for each regulatory option.

Table 7-10 Net Imports of Natural Gas and Crude Oil, NSPS Options

	2011	Future NSPS Scenario, 2015			
		Baseline	Option 1	Option 2 (Proposed)	Option 3
Net Imports					
Natural Gas (trillion cubic feet)	2.75	2.69	2.69	2.69	2.69
Crude Oil (million barrels/day)	9.13	8.70	8.70	8.70	8.70
% Change in Net Imports					
Natural Gas			0.00%	0.00%	0.00%
Crude Oil			0.00%	0.00%	0.00%

Table 7-11 evaluates estimates of energy consumption by energy type at the national level for 2015, the year of analysis. All three NSPS options are estimated to have small effects at the national level. For Option 1, we estimate an increase in 0.02 quadrillion BTU in 2015, a 0.02 percent increase. The percent contribution of natural gas and biomass is projected to increase, while the percent contribution of liquid fuels and coal is expected to decrease under Option 1. Meanwhile, under the proposed Options 2, total energy consumption is also forecast to rise 0.02 quadrillion BTU, with increase coming from natural gas primarily, with an additional small increase in coal consumption. Under Option 3, total energy consumption is forecast to rise 0.01 quadrillion BTU, or 0.01%, with a slight decrease in liquid fuel consumption from the baseline, but increases in natural gas and coal consumption.

Table 7-11 Total Energy Consumption by Energy Type (Quadrillion BTU), NSPS Options

	2011	Future NSPS Scenario, 2015 Baseline	Option 1	Option 2 (Proposed)	Option 3
Consumption (quadrillion BTU)					
Liquid Fuels	37.41	39.10	39.09	39.10	39.09
Natural gas	24.49	25.77	25.82	25.79	25.79
Coal	20.42	19.73	19.71	19.74	19.74
Nuclear Power	8.40	8.77	8.77	8.77	8.77
Hydropower	2.58	2.92	2.92	2.92	2.92
Biomass	2.98	3.27	3.28	3.27	3.27
Other Renewable Energy	1.72	2.14	2.14	2.14	2.14
Other	0.30	0.31	0.31	0.31	0.31
Total	**98.29**	**102.02**	**102.04**	**102.04**	**102.03**
% Change in Consumption from Baseline					
Liquid Fuels			-0.03%	0.00%	-0.03%
Natural Gas			0.19%	0.08%	0.08%
Coal			-0.10%	0.05%	0.05%
Nuclear Power			0.00%	0.00%	0.00%
Hydropower			0.00%	0.00%	0.00%
Biomass			0.31%	0.00%	0.00%
Other Renewable Energy			0.00%	0.00%	0.00%
Other			0.00%	0.00%	0.00%
Total			**0.02%**	**0.02%**	**0.01%**

Note: Totals may not sum due to independent rounding.

With the national profile of energy consumption estimated to change slightly under the regulatory options in 2015, the year of analysis, it is important to examine whether aggregate energy-related CO_2-equivalent greenhouse gas (GHG) emissions also shift. A more detailed discussion of changes in CO_2-equivalent GHG emissions from a baseline is presented within the benefits analysis in Section 4. Here, we present a single NEMS-based table showing estimated changes in energy-related "consumer-side" GHG emissions. We use the terms "consumer-side" emissions to distinguish emissions from the consumption of fuel from emissions specifically associated with the extraction, processing, and transportation of fuels in the oil and natural gas sector under examination in this RIA. We term the emissions associated with extraction, processing, and transportation of fuels "producer-side" emissions.

Table 7-12 Modeled Change in Energy-related "Consumer-Side" CO_2-equivalent GHG Emissions

	2011	Future NSPS Scenario, 2015 Baseline	Option 1	Option 2 (Proposed)	Option 3
Energy-related CO_2-equivalent GHG Emissions (million metric tons CO_2-equivalent)					
Petroleum	2,359.59	2,433.60	2,433.12	2,433.49	2,433.45
Natural Gas	1,283.78	1,352.20	1,354.47	1,353.19	1,352.87
Coal	1,946.02	1,882.08	1,879.84	1,883.24	1,883.30
Other	11.99	11.99	11.99	11.99	11.99
Total	**5,601.39**	**5,679.87**	**5,679.42**	**5,681.91**	**5,681.61**
% Change in Energy-related CO_2-equivalent GHG Emissions from Baseline					
Petroleum			-0.02%	0.00%	-0.01%
Natural Gas			0.17%	0.07%	0.05%
Coal			-0.12%	0.06%	0.06%
Other			0.00%	0.00%	0.00%
Total			**-0.01%**	**0.04%**	**0.03%**

Note: Excludes "producer-side" emissions and emissions reductions estimated to result from NSPS alternatives. Totals may not sum due to independent rounding.

As is shown in Table 7-12, NSPS Option 1 is predicted to slightly decrease aggregate consumer-side energy-related CO_2-equivalent GHG emissions, by about 0.01 percent, while the mix of emissions shifts slightly away from coal and petroleum toward natural gas. Proposed Options 2 and 3 are estimated to increase consumer-side aggregate energy-related CO_2-equivalent GHG emissions by about 0.04 and 0.03 percent, respectively, mainly because consumer-side emissions from natural gas and coal combustion increase slightly.

7.3 Employment Impact Analysis

While a standalone analysis of employment impacts is not included in a standard cost-benefit analysis, such an analysis is of particular concern in the current economic climate of sustained high unemployment. Executive Order 13563, states, "Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation" (emphasis added). Therefore, we seek to inform the discussion of labor demand and job impacts by providing an estimate of the employment impacts of the proposed regulations using labor requirements for the installation, operation, and maintenance of control requirements, as well as reporting and recordkeeping requirements. Unlike several recent RIAs, however, we do not provide employment impacts estimates based on the study by Morgenstern et al. (2002); we discuss this decision after presenting estimates of the labor requirements associated with reporting and recordkeeping and the installation, operation, and maintenance of control requirements.

7.3.1 Employment Impacts from Pollution Control Requirements

Regulations set in motion new orders for pollution control equipment and services. New categories of employment have been created in the process of implementing regulations to make our air safer to breathe. When a new regulation is promulgated, a response of industry is to order pollution control equipment and services in order to comply with the regulation when it becomes effective. Revenue and employment in the environmental technology industry have grown steadily between 2000 and 2008, reaching an industry total of approximately $300 billion in revenues and 1.7 million employees in 2008.[52] While these revenues and employment figures represent gains for the environmental technologies industry, they are costs to the regulated industries required to install the equipment. Moreover, it is not clear the 1.7 million employees in 2008 represent new employment as opposed to workers being shifted from the production of goods and services to environmental compliance activities.

Once the equipment is installed, regulated firms hire workers to operate and maintain the pollution control equipment – much like they hire workers to produce more output. Morgenstern et al. (2002) examined how regulated industries respond to regulation. The authors found that, on average for the industries they studied, employment increases in regulated firms. Of course, these firms may also reassign existing employees to perform these activities.

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[52] In 2008, the industry totaled approximately $315 billion in revenues and 1.9 million employees including indirect employment effects, pollution abatement equipment production employed approximately 4.2 million workers in 2008. These indirect employment effects are based on a multiplier for indirect employment = 2.24 (1982 value from Nestor and Pasurka - approximate middle of range of multipliers 1977-1991). Environmental Business International (EBI), Inc., San Diego, CA. Environmental Business Journal, monthly (copyright). http://www.ebiusa.com/ EBI data taken from the Department of Commerce International Trade Administration Environmental Industries Fact Sheet from April 2010: http://web.ita.doc.gov/ete/eteinfo.nsf/068f3801d047f26e85256883006ffa54/4878b7e2fc08ac6d85256883006c452c?OpenDocument

Environmental regulations support employment in many basic industries. In addition to the increase in employment in the environmental protection industry (via increased orders for pollution control equipment), environmental regulations also support employment in industries that provide intermediate goods to the environmental protection industry. The equipment manufacturers, in turn, order steel, tanks, vessels, blowers, pumps, and chemicals to manufacture and install the equipment. Bezdek et al. (2008) found that investments in environmental protection industries create jobs and displace jobs, but the net effect on employment is positive.

The focus of this part of the analysis is on labor requirements related to the compliance actions of the affected entities within the affected sector. We do not estimate any potential changes in labor outside of the oil and natural gas sector. This analysis estimates the employment impacts due to the installation, operation, and maintenance of control equipment, as well as employment associated with new reporting and recordkeeping requirements.

It is important to highlight that unlike the typical case where to reduce a bad output (i.e., emissions) a firm often has to reduce production of the good output, many of the emission controls required by the proposed NSPS will simultaneously increase production of the good output and reduce production of bad outputs. That is, these controls jointly produce environmental improvements and increase output in the regulated sector. New labor associated with implementing these controls to comply with the new regulations can also be viewed as additional labor increasing output while reducing undesirable emissions.

No estimates of the labor used to manufacture or assemble pollution control equipment or to supply the materials for manufacture or assembly are included because U.S. EPA does not currently have this information. The employment analysis uses a bottom-up engineering-based methodology to estimate employment impacts. The engineering cost analysis summarized in this RIA includes estimates of the labor requirements associated with implementing the proposed regulations. Each of these labor changes may either be required as part of an initial effort to comply with the new regulation or required as a continuous or annual effort to maintain compliance. We estimate up-front and continual, annual labor requirements by estimating hours of labor required and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

In other employment analyses U.S. EPA distinguished between employment changes within the regulated industry and those changes outside the regulated industry (e.g. a contractor from outside the regulated facility is employed to install a control device). For this regulation however, the structure of the industry makes this difficult. The mix of in-house versus contracting services used by firms is very case-specific in the oil and natural gas industry. For example, sometimes the owner of the well, processing plant, or transmission pipelines uses in–house employees extensively in daily operations, while in other cases the owner relies on outside contractors for many of these services. For this reason, we make no distinction in the quantitative estimates between labor changes within and outside of the regulated sector.

The results of this employment estimate are presented in Table 7-13 for the proposed NSPS and in Table 7-14 for the proposed NESHAP amendments. The tables breaks down the installation, operation, and maintenance estimates by type of pollution control evaluated in the RIA and present both the estimated hours required and the conversion of this estimate to FTE. For both the proposed NSPS and NESHAP amendments, reporting and recordkeeping requirements were estimated for the entire rules rather than by anticipated control requirements; the reporting and recordkeeping estimates are consistent with estimates EPA submitted as part of its Information Collection Request (ICR).

The up-front labor requirement is estimated at 230 FTEs for the proposed NSPS and about 120 FTEs for the proposed NESHAP amendments. These up-front FTE labor requirements can be viewed as short-term labor requirements required for affected entities to comply with the new regulation. Ongoing requirements are estimated at about 2,400 FTEs for the proposed NSPS and about 102 FTEs for the proposed NESHAP amendments. These ongoing FTE labor requirements can be viewed as sustained labor requirements required for affected entities to continuously comply with the new regulation

Two main categories contain the majority of the labor requirements for the proposed rules: implementing reduced emissions completions (RECs) and reporting and recordkeeping requirements for the proposed NSPS. Also, note that pneumatic controllers have no up-front or continuing labor requirements. While the controls do require labor for installation, operation, and maintenance, the required labor is less than that of the controllers that would be used absent the regulation. In this instance, we assume the incremental labor requirements are zero.

Implementing RECs are estimated to require about 2,230 FTE, over 90 percent of the total continuing labor requirements for the proposed NSPS.[53] We denote REC-related requirements as continuing, or annual, as the REC requirements will in fact recur annually, albeit at different wells each year. The REC requirements are associated with certain new well completions or existing well recompletions, which while individual completions occur over a short period of time (days to a few weeks), new wells and other existing wells are completed or recompleted annually. Because of these reasons, we assume the REC-related labor requirements are annual.

7.3.2 Employment Impacts Primarily on the Regulated Industry

In previous RIAs, we transferred parameters from a study by Morgenstern et al. (2002) to estimate employment effects of new regulations. (See, for example, the Regulatory Impact Analysis for the recently finalized Industrial Boilers and CISWI rulemakings, promulgated on February 21, 2011). The fundamental insight of Morgenstern, et al. is that environmental regulations can be understood as requiring regulated firms to add a new output (environmental quality) to their product mixes. Although legally compelled to satisfy this new demand, regulated firms have to finance this additional production with the proceeds of sales of their other (market) products. Satisfying this new demand requires additional inputs, including labor, and may alter the relative proportions of labor and capital used by regulated firms in their production processes.

Morgenstern et al. concluded that increased abatement expenditures in these industries generally do not cause a significant change in employment. Using plant-level Census

[53] As shown on earlier in this section, we project that the number of successful natural gas wells drilled in 2015 will decline slightly from the baseline projection. Therefore, there may be small employment losses in drilling-related employment that partly offset gains in employment from compliance-related activities.

information between the years 1979 and 1991, Morgenstern et al. estimate the size of each effect for four polluting and regulated industries (petroleum refining, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million (1987$) spending on pollution abatement results in a (statistically insignificant) net increase of 1.55 (+/- 2.24) jobs. As a result, the authors conclude that increases in pollution abatement expenditures do not necessarily cause economically significant employment changes.

For this version of RIA for the proposed NSPS and NESHAP amendments, however, we chose not to quantitatively estimate employment impacts using Morgenstern et al. because of reasons specific to the oil and natural gas industry and proposed rules. We believe the transfer of parameter estimates from the Morgenstern et al. study to the proposed NSPS and NESHAP amendments is beyond the range of the study for two reasons.

Table 7-13 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NSPS Option in 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit Up- Front Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total Up- Front Labor Estimate (hours)	Total Annual Labor Estimate (hours)	Up-Front Full-Time Equivalent	Annual Full-Time Equivalent
Well Completions								
Hydraulically Fractured Gas Wells	Reduced Emissions Completion (REC)	9,313	0	218	0	2,025,869	0.0	974.0
Hydraulically Fractured Gas Wells	Combustion	446	0	22	0	9,626	0.0	4.6
Well Recompletions								
Hydraulically Fractured Gas Wells (pre-NSPS wells)	REC	12,050	0	218	0	2,621,126	0.0	1,260.2
Equipment Leaks								
Processing Plants	NSPS Subpart VVA	29	587	887	17,023	25,723	8.2	12.4
Reciprocating Compressors								
Gathering/Boosting Stations	AMM	210	1	1	210	210	0.1	0.1
Processing Plants	AMM	375	1	1	375	375	0.2	0.2
Transmission Compressor Stations	AMM	199	1	1	199	199	0.1	0.1
Underground Storage Facilities	AMM	9	1	1	9	9	0.0	0.0
Centrifugal Compressors								
Processing Plants	Dry Seals/Route to Process or Control	16	355	0	5,680	0	2.7	0.0
Transmission Compressor Stations	Dry Seals/Route to Process or Control	14	355	0	4,970	0	2.4	0.0
Pneumatic Controllers								
Oil and Gas Production	Low Bleed/Route to Process	13,632	0	0	0	0	0.0	0.0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	67	0	0	0	0	0.0	0.0
Storage Vessels								
High Throughput	95% control	304	271	190	82,279	57,582	39.6	27.7
Reporting and Recordkeeping for Complete NSPS		---	---	---	360,443	201,342	173.3	96.8
TOTAL		**---**	**---**	**---**	**471,187**	**4,942,060**	**226.5**	**2,376.0**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 7-14 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NESHAP Amendments in 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit One-time Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total One-Time Labor Estimate (hours)	Total Annual Labor Estimate (hours)	One-time Full-Time Equivalent	Annual Full-Time Equivalent
Small Glycol Dehydrators								
Production	Combustion devices, recovery devices, process modifications	115	27	285	3,108	32,821	1.5	15.8
Transmission	Combustion devices, recovery devices, process modifications	19	27	285	513	5,423	0.2	2.6
Storage Vessels								
Production	Combustion devices, recovery devices	674	311	198	209,753	133,231	100.8	64.1
Reporting and Recordkeeping for Complete NESHAP Amendments		---	---	---	36,462	39,923	17.5	19.2
TOTAL		**---**	**--**	**---**	**249,836**	**211,398**	**120.1**	**101.6**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

First, the possibility that the revenues producers are estimated to receive from additional natural gas recovery as a result of the proposed NSPS might offset the costs of complying with the rule presents challenges to estimating employment effects (see Section 3.2.2.1 of the RIA for a detailed discussion of the natural gas recovery). The Morgenstern et al. paper, for example, is intended to analyze the impact of environmental compliance expenditures on industry employment levels, and it may not be appropriate to draw on their demand and net effects when compliance costs are expected to be negative.

Second, the proposed regulations primarily affect the natural gas production, processing, and transmission segments of the industry. While the natural gas processing segment of the oil and natural gas industry is similar to petroleum refining, which is examined in Morgenstern et al., the production side of the oil and natural gas (drilling and extraction, primarily) and natural gas pipeline transmission are not similar to petroleum refining. Because of the likelihood of negative compliance costs for the proposed NSPS and the segments of the oil and natural gas industry affected by the proposals are not examined by Morgenstern et al., we decided not to use the parameters estimated by Morgenstern et al. to estimate within-industry employment effects for the proposed oil and natural gas NESHAP amendments and NSPS.

That said, the likelihood of additional natural gas recovery is an important component of the market response to the rule, as it is expected that this additional natural gas recovery will reduce the price of natural gas. Because of the estimated fall in prices in the natural gas sector due to the proposed NSPS, prices in other sectors that consume natural gas are likely drop slightly due to the decrease in energy prices. This small production increase and price decrease may have a slight stimulative effect on employment in industries that consume natural gas.

7.4 Small Business Impacts Analysis

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

After considering the economic impact of the proposed rules on small entities for both the NESHAP and NSPS, the screening analysis indicates that these proposed rules will not have a significant economic impact on a substantial number of small entities (or "SISNOSE"). The supporting analyses for these determinations are presented in this section of the RIA.

As discussed in previous sections of the economic impact analysis, under the proposed NSPS, some affected producers are likely to be able to recover natural gas that would otherwise be vented to the atmosphere, as well as recover saleable condensates that would otherwise be emitted. EPA estimates that the revenues from this additional natural gas product recovery will offset the costs of implementing control options implemented as a result of the Proposed NSPS. Because the total costs of the rule are likely to be more than offset by the revenues producers gain from increased natural gas recovery, we expect there will be no SISNOSE arising from the proposed NSPS. However, not all components of the proposed NSPS are estimated to have cost savings. Therefore, we analyze potential impacts to better understand the potential distribution of impacts across industry segments and firms. We feel taking this approach strengthens the determination that there will be no SISNOSE. Unlike the controls for the proposed NSPS, the controls evaluated under the proposed NESHAP amendments do not recover significant quantities of natural gas products.

7.4.1 Small Business National Overview

The industry sectors covered by the final rule were identified during the development of the engineering cost analysis. The U.S. Census Bureau's Statistics of U.S. Businesses (SUSB) provides national information on the distribution of economic variables by industry and enterprise size. The Census Bureau and the Office of Advocacy of the Small Business Administration (SBA) supported and developed these files for use in a broad range of economic analyses.[54] Statistics include the total number of establishments, and receipts for all entities in an industry; however, many of these entities may not necessarily be covered by the final rule. SUSB also provides statistics by enterprise employment and receipt size (Table 7-15 and Table 7-16).

[54]See http://www.census.gov/csd/susb/ and http://www.sba.gov/advocacy/ for additional details.

The Census Bureau's definitions used in the SUSB are as follows:

- *Establishment*: A single physical location where business is conducted or where services or industrial operations are performed.
- *Firm:* A firm is a business organization consisting of one or more domestic establishments in the same state and industry that were specified under common ownership or control. The firm and the establishment are the same for single-establishment firms. For each multi-establishment firm, establishments in the same industry within a state will be counted as one firm- the firm employment and annual payroll are summed from the associated establishments.
- *Receipts*: Receipts (net of taxes) are defined as the revenue for goods produced, distributed, or services provided, including revenue earned from premiums, commissions and fees, rents, interest, dividends, and royalties. Receipts exclude all revenue collected for local, state, and federal taxes.
- *Enterprise*: An enterprise is a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the sum of employment of all associated establishments.

Because the SBA's business size definitions (SBA, 2008) apply to an establishment's "ultimate parent company," we assumed in this analysis that the "firm" definition above is consistent with the concept of ultimate parent company that is typically used for SBREFA screening analyses, and the terms are used interchangeably.

Table 7-15 Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

			Owned by Firms with:					
NAICS	NAICS Description	SBA Size Standard (effective Nov. 5, 2010)	< 20 Employees	20-99 Employees	100-499 Employees	Total < 500 Employees	> 500 Employees	Total Firms
Number of Firms by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	5,759	455	115	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	77	9	12	98	41	139
213111	Drilling Oil and Gas Wells	500	1,580	333	97	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	63	12	9	84	42	126
Total Employment by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	21,170	16,583	17,869	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	372	305	1,198	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	5,972	13,787	16,893	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	241	382	1,479	2,102	22,581	24,683
Estimated Receipts by Firm Size ($1000)								
211111	Crude Petroleum and Natural Gas Extraction	500	12,488,688	15,025,443	17,451,805	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	209,640	217,982	1,736,706	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	1,101,481	2,460,301	3,735,652	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	332,177	518,341	1,448,020	2,298,538	18,498,143	20,796,681

Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007." <http://www.census.gov/econ/susb/>

Table 7-16 Distribution of Small and Large Firms by Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

			Percent of Firms		
NAICS	NAICS Description	Total Firms	Small Businesses	Large Businesses	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	6,424	98.5%	1.5%	100.0%
211112	Natural Gas Liquid Extraction	139	70.5%	29.5%	100.0%
213111	Drilling Oil and Gas Wells	2,059	97.6%	2.4%	100.0%
486210	Pipeline Transportation of Natural Gas	126	48.4%	51.6%	100.0%
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	133,286	41.7%	58.3%	100.0%
211112	Natural Gas Liquid Extraction	8,523	22.0%	78.0%	100.0%
213111	Drilling Oil and Gas Wells	106,426	34.4%	65.6%	100.0%
486210	Pipeline Transportation of Natural Gas	24,683	N/A*	N/A*	N/A*
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	194,107,252	23.2%	76.8%	100.0%
211112	Natural Gas Liquid Extraction	39,977,741	5.4%	94.6%	100.0%
213111	Drilling Oil and Gas Wells	23,848,238	30.6%	69.4%	100.0%
486210	Pipeline Transportation of Natural Gas	20,796,681	N/A*	N/A*	N/A*

Note: Employment and receipts could not be broken down between small and large businesses because of non-disclosure requirements.

Source: SBA

While the SBA and Census Bureau statistics provide informative broad contextual information on the distribution of enterprises by receipts and number of employees, it is also useful to additionally contrast small and large enterprises (where large enterprises are defined as those that are not small, according to SBA criteria) in the oil and natural gas industry. The summary statistics presented in previous tables indicate that there are a large number of relatively small firms and a small number of large firms. Given the majority of expected impacts of the proposed rules arises from well completion-related requirements, which impacts production activities, exclusively, some explanation of this particular market structure is warranted as it pertains to production and small entities. An important question to answer is whether there are particular roles that small entities serve in the production segment of the oil and natural gas industry that may be disproportionately affected by the proposed rules.

The first important broad distinction among firms is whether they are independent or integrated. Independent firms concentrate on exploration and production (E&P) activities, while integrated firms are vertically integrated and often have operations in E&P, processing, refining, transportation, and retail. To our awareness, there are no small integrated firms. Independent firms may own and operate wells or provide E&P-related services to the oil and gas industry. Since we are focused on evaluating potential impacts to small firms owning and operating new and existing hydraulically fractured wells, we should narrow down on this sector.

In our understanding, there is no single industry niche for small entities in the production segment of the industry since small operators have different business strategies and that small entities can own different types of wells. The organization of firms in oil and natural gas industry also varies greatly from firm to firm. Additionally, oil and natural gas resources vary widely geographically and can vary significantly within a single field.

Among many important roles, independent small operators historically pioneered exploration in new areas, as well as developed new technologies. By taking on these relatively large risks, these small entrepreneurs (wildcatters) have been critical sources of industrial innovation and opened up critical new energy supplies for the U.S. (HIS Global Insight). In recent decades, as the oil and gas industry has concentrated via mergers, many of these smaller firms have been absorbed into large firms.

Another critical role, which provides an interesting contrast to small firms pioneering new territory, is that smaller independents maintain and operate a large proportion of the Nation's low producing wells, which are also known as marginal or stripper wells (Duda et al. 2005). While marginal wells represent about 80 percent of the population of producing wells, they produce about 15 percent of domestic production, according to EIA (Table 7-17).

Table 7-17 Distribution of Crude Oil and Natural Gas Wells by Productivity Level, 2009

Type of Wells	Wells (no.)	Wells (%)	Production (MMbbl for oil and Bcf gas)	Production (%)
Crude Oil				
Stripper Wells (<15 boe per year)	310,552	85%	311	19%
Other Wells (>=15 boe per year)	52,907	15%	1,331	81%
Total Crude Oil Wells	**363,459**	**100%**	**1,642**	**100%**
Natural Gas				
Natural Gas Stripper Wells (<15 boe per year)	338,056	73%	2,912	12%
Other Natural Gas Wells (>=15 boe per year)	123,332	27%	21,048	88%
Total Natural Gas Wells	**461,388**	**100%**	**23,959**	**100%**

Source: U.S. Energy Information Administration, **Distribution of Wells by Production Rate Bracket.** <http://www.eia.gov/pub/oil_gas/petrosystem/us_table.html> Accessed 7/10/11.

Note: Natural gas production converted to barrels oil equivalent (boe) uses the conversion of 0.178 barrels of crude oil to 1000 cubic feet natural gas.

Many of these wells were likely drilled and initially operated by major firms (although the data are not available to quantify the percentage of wells initially drilled by small versus large producers). Well productivity levels typically follow a steep decline curve; high production in earlier years but sustained low production for decades. Because of relatively low overhead of maintaining and operating few relatively co-located wells, some small operators with a particular business strategy purchase low producing wells from the majors, who concentrate on new opportunities. As small operators have provided important technical innovation in exploration, small operators have also been sources of innovation in extending the productivity and lifespan of existing wells (Duda et al. 2005).

7.4.2 Small Entity Economic Impact Measures

The proposed Oil and Natural Gas NSPS and NESHAP amendments will affect the owners of the facilities that will incur compliance costs to control their regulated emissions. The owners, either firms or individuals, are the entities that will bear the financial impacts associated with these additional operating costs. The proposed rule has the potential to impact all firms owning affected facilities, both large and small.

The analysis provides EPA with an estimate of the magnitude of impacts the proposed NSPS and NESHAP amendments may have on the ultimate domestic parent companies that own facilities EPA expects might be impacted by the rules. The analysis focuses on small firms because they may have more difficulty complying with a new regulation or affording the costs associated with meeting the new standard. This section presents the data sources used in the screening analysis, the methodology we applied to develop estimates of impacts, the results of the analysis, and conclusions drawn from the results.

The small business impacts analysis for the NSPS and NESHAP amendments relies upon a series of firm-level sales tests (represented as cost-to-revenue ratios) for firms that are likely to be associated with NAICS codes listed in Table 7-15. For both the NSPS and NESHAP amendments, we obtained firm-level employment, revenues, and production levels using various sources, including the American Business Directory, the *Oil and Gas Journal*, corporate websites, and publically-available financial reports. Using these data, we estimated firm-level compliance cost impacts and calculated cost-to-revenue ratios to identify small firms that might be significantly impacts by the rules. The approaches taken for the NSPS and NESHAP amendments differed; more detail on approaches for each set of proposed rules is presented in the following sections.

For the sales test, we divided the estimates of annualized establishment compliance costs by estimates of firm revenue. This is known as the cost-to-revenue ratio, or the "sales test." The "sales test" is the impact methodology EPA employs in analyzing small entity impacts as opposed to a "profits test," in which annualized compliance costs are calculated as a share of profits. The sales test is often used because revenues or sales data are commonly available for entities impacted by EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Revenues as typically published are correct figures and are more reliably reported when compared to profit data. The use of a "sales test" for estimating small business impacts for a rulemaking such as this one is consistent with guidance offered by EPA on compliance with SBREFA[55] and is consistent with guidance published by the U.S. SBA's Office of Advocacy that suggests that cost as a percentage

[55] The SBREFA compliance guidance to EPA rulewriters regarding the types of small business analysis that should be considered can be found at <http://www.epa.gov/sbrefa/documents/rfaguidance11-00-06.pdf>

of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities (U.S. SBA, 2010).[568]

7.4.3 Small Entity Economic Impact Analysis, Proposed NSPS

7.4.3.1 Overview of Sample Data and Methods

The proposed NSPS covers emissions points within various stages of the oil and natural gas production process. We expect that firms within multiple NAICS codes will be affected, namely the NAICS categories presented in Table 7-15. Because of the diversity of the firms potentially affected, we decided to analyze three distinct groups of firms within the oil and natural gas industry, while accounting for overlap across the groups. We analyze firms that are involved in oil and natural gas extraction that are likely to drill and operate wells, while a subset are integrated firms involved in multiple segments of production, as well as retailing products. We also analyze firms that primarily operate natural gas processing plants. A third set of firms we analyzed contains firms that primarily operate natural gas compression and pipeline transmission.

To identify firms involved in the drilling and primary production of oil and natural gas, we relied upon the annual *Oil and Gas Journal* 150 Survey (OGJ 150) as described in the Industry Profile in Section 2. While the OGJ 150 lists public firms, we believe the list is reasonably representative of the larger population of public and private firms operating in this segment of the industry. While the proportion of small firm in the OGJ 150 is smaller than the proportion evaluated by the Census SUSB, the OGJ 150 provides detailed information on the production activities and financial returns of the firms within the list, which are critical ingredients to the small business impacts analysis. We drew upon the OGJ 150 lists published for the years 2008 and 2009 (*Oil and Gas Journal*, September 21, 2009 and *Oil and Gas Journal*, September 6, 2010). The year 2009 saw relatively low levels of drilling activities because of the economic recession, while 2008 saw a relatively high level of drilling activity because of high fuel prices. Combined, we believe these two years of data are representative.

[56]U.S. SBA, Office of Advocacy. A Guide for Government Agencies, How to Comply with the Regulatory Flexibility Act, Implementing the President's Small Business Agenda and Executive Order 13272, June 2010.

To identify firms that process natural gas, the OGJ also releases a period report entitled "Worldwide Gas Processing Survey", which provides a wide range of information on existing processing facilities. We used the most recent list of U.S. gas processing facilities[57] and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. To identify firms that compress and transport natural gas via pipelines, we examined the periodic OGJ survey on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies.[58] For these firms, we also used the American Business Directory and corporate websites to best identify the ultimate owner of the facilities or companies.

After combining the information for exploration and production firms, natural gas processing firms, and natural gas pipeline transmission firms in order to identify overlaps across the list, the approach yielded a sample of 274 firms that would potentially be affected by the proposed NSPS in 2015 assuming their 2015 production activities were similar to those in 2008 and 2009. We estimate that 129 (47 percent) of these firms are small according to SBA criteria. We estimate 121 firms (44 percent) are not small firms according to SBA criteria. We are unable to classify the remaining 24 firms (9 percent) because of a lack of required information on employee counts or revenue estimates.

Table 7-18 shows the estimated revenues for 250 firms for which we have sufficient data that would be potentially affected by the proposed NSPS based upon their activities in 2008 and 2009. We segmented the sample into four groups, production and integrated firms, processing firms, pipeline firms, and pipelines/processing firms. For the firms in the pipelines/processing group, we were unable to determine the firms' primary line of business, so we opted to group together as a fourth group.

[57] Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010.
[58] Oil and Gas Journal. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

Table 7-18 Estimated Revenues for Firms in Sample, by Firm Type and Size

		Estimated Revenues (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Production and Integrated						
Small	79	18,554.5	234.9	76.3	0.1	1,116.9
Large	49	1,347,463.0	27,499.2	1,788.3	12.9	310,586.0
Subtotal	128	1,366,017.4	10,672.0	344.6	0.1	310,586.0
Pipeline						
Small	11	694.5	63.1	4.6	0.5	367.0
Large	36	166,290.2	4,619.2	212.9	7.1	112,493.0
Subtotal	47	166,984.6	3,552.9	108.0	0.5	112,493.0
Processing						
Small	39	4,972.1	127.5	26.9	1.9	1,459.1
Large	23	177,632.1	8,881.6	2,349.4	10.4	90,000.0
Subtotal	62	182,604.2	3,095.0	41.3	1.9	90,000.0
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Subtotal	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Total						
Small	**129**	**24,221.1**	**187.8**	**34.9**	**0.1**	**1,459.1**
Large	**121**	**1,866,513.7**	**15,817.9**	**1,672.1**	**7.1**	**310,586.0**
Total	**250**	**1,890,734.8**	**7,654.8**	**163.9**	**0.1**	**310,586.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants. *Oil and Gas Journal*. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010. American Business Directory was used to determine number of employees.

As shown in Table 7-18, there is a wide variety of revenue levels across firm size, as well as across industry segments. The estimated revenues within the sample are concentrated on integrated firms and firms engaged in production activities (the E&P firms mentioned earlier).

The oil and natural gas industry is capital-intensive. To provide more context on the potential impacts of new regulatory requirements, Table 7-19 presents descriptive statistics for small and large integrated and production firms from the sample of firms (121 of the 128 integrated and production firms listed in the *Oil and Gas Journal*; capital and exploration expenditures for 7 firms were not reported in the *Oil and Gas Journal*).

Table 7-19 Descriptive Statistics of Capital and Exploration Expenditures, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

		Capital and Exploration Expenditures (millions, 2008 dollars)				
Firm Size	Number	Total	Average	Median	Minimum	Maximum
Small	76	13,478.8	177.4	67.1	0.1	2,401.9
Large	45	126,749.3	2,816.7	918.1	10.3	22,518.7
Total	**121**	**140,228.2**	**1,158.9**	**192.8**	**0.1**	**22,518.7**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

The average 2008 and 2009 total capital and exploration expenditures for the sample of 121 firms were $140 billion in 2008 dollars). About 10 percent of this total was spent by small firms. Average capital and explorations expenditures for small firms are about 6 percent of large firms; median expenditures of small firms are about 7 percent of large firms' expenditures. For small firms, capital and exploration expenditures are high relative to revenue, which appears to hold true more generally for independent E&P firms compared to integrated major firms. This would seem to indicate the capital-intensive nature of E&P activities. As expected, this would drive up ratios comparing estimated engineering costs to revenues and capital and exploration expenditures.

Table 7-20 breaks down the estimated number of natural gas and crude oil wells drilled by the 121 firms in the sample for which the *Oil and Gas Journal* information reported well-drilling estimates. Note the fractions on the minimum and maximum statistics; the fractions reported are due to our assumptions to estimate oil and natural gas wells drilled from the total wells drilled reported by the *Oil and Gas Journal*. The OGJ150 lists new wells drilled by firm in 2008 and 2009, but the drilling counts are not specific to crude oil or natural gas wells. We apportion the wells drilled to natural gas and crude oil wells using the distribution of well drilling in 2009 (63 percent natural gas and 37 percent oil).

Table 7-20 Descriptive Statistics of Estimated Wells Drilled, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

			Estimated Average Wells Natural Gas and Crude Oil Wells Drilled (2008 and 2009)				
Well Type	Firm Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Natural Gas							
	Small	76	2,288.3	30.1	6.0	0.2	259.3
	Large	45	9,445.1	209.9	149.1	0.6	868.3
	Subtotal	121	11,733.4	97.0	28.3	0.2	868.3
Crude Oil							
	Small	76	1,317.1	17.3	3.5	0.1	149.2
	Large	45	5,436.3	120.8	85.8	0.4	499.7
	Subtotal	121	6,753.4	55.8	16.3	0.1	499.7
Total							
	Small	**76**	**3,605.4**	**47.4**	**9.5**	**0.0**	**408.5**
	Large	**45**	**14,881.4**	**330.7**	**234.9**	**0.0**	**1,368.0**
	Total	**121**	**18,486.8**	**152.8**	**44.6**	**0.0**	**1,368.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

This table highlights the fact that many firms drill relatively few wells; the median for small firms is 6 natural gas wells compared to 149 for large firms. Later in this section, we examine whether this distribution has implications for the engineering costs estimates, as well as the estimates of expected natural product recovery from controls such as RECs.

Unlike the analysis that follows for the analysis of impacts on small business from the NESHAP amendments, we have no specific data on potentially affected facilities under the NSPS. The NSPS will apply to new and modified sources, for which data are not fully available in advance, particularly in the case of new and modified sources such as well completions and recompletions which are spatially diffuse and potentially large in number.

The engineering cost analysis estimated compliance costs in a top-down fashion, projecting the number of new sources at an annual level and multiplying these estimates by model unit-level costs to estimate national impacts. To estimate per-firm compliance costs in this analysis, we followed a procedure similar to that of entering estimate compliance costs in NEMS on a per well basis. We first use the OGJ150-based list to estimate engineering compliance costs for integrated and production companies that may operate facilities in more than one segment of the oil and natural gas industry. We then estimate the compliance costs per crude oil and natural gas well by totaling all compliance costs estimates in the engineering cost estimates for the proposed NSPS and dividing that cost by the total number of crude oil and natural gas wells forecast as of 2015, the year of analysis. These compliance costs include the expected revenue from natural gas and condensate recovery that result from implementation of some proposed controls.

This estimation procedure yielded an estimate of crude well compliance costs of $162 per drilled well and natural gas well compliance costs of $38,719 without considering estimated revenues from product recovery and -$2,455 per drilled well with estimated revenues from product recovery included. Note that the divergence of estimated per well costs between crude oil and natural gas wells is because the proposed NSPS requirements are primary directed toward natural gas wells. Also note that the per well cost savings estimate for natural gas wells is different than the estimated cost of implementing a REC; this difference is because this estimate is picking up savings from other control options. We then estimate a single-year, firm-level compliance cost for this subset of firms by multiplying the per well cost estimates with the well count estimates.

The OGJ reports plant processing capacity in terms of MMcf/day. In the energy system impacts analysis, the NEMS model estimates a 6.5 percent increase (from 21.05 tcf in 2011 to 22.43 tcf in 2015) in domestic natural gas production from 2011 to 2015, the analysis year. On this, basis, we estimate that natural gas processing capacity for all plants in the OGJ list will increase 1.3 percent per year. This annual increment is equivalent to an increase in national gas processing capacity of 350 bcf per year. We assume that the engineering compliance costs estimates associated with processing are distributed according to the proportion of the increased national processing capacity contributed by each processing plant. These costs are estimated at $6.9 million without estimated revenues from product recovery and $2.3 million with estimated revenues from product recovery, respectively, in 2008 dollars, or about \$20/MMcf without revenues and \$7/MMcf with revenues.

The OGJ report on pipeline companies has the advantage that it reports expenditures on plant additions. We assume that the firm-level proposed compression and transmission-related NSPS compliance costs are proportional to the expenditures on plant additions and that these additions reflect a representative year or this analysis. We estimate the annual compression and transmission-related NSPS compliance costs at \$5.5 million without estimated revenues from product recovery and \$3.7 million with estimated revenues from product recovery, respectively, in 2008 dollars.

7.4.3.2 Small Entity Impact Analysis, Proposed NSPS, Results

Summing estimated annualized engineering compliance costs across industry segment and individual firms in our sample, we estimate firms in the OGJ-based sample will face about \$480 million in 2008 dollars, about 65 percent of the estimated annualized costs of the Proposed NSPS without including revenues from additional product recovery (\$740 million). When including revenues from additional product recovery, the estimated compliance costs for the firms in the sample is about -\$23 million, compared to engineering cost estimate of -\$45 million.

Table 7-21 presents the distribution of estimated proposed NSPS compliance costs across firm size for the firms within our sample. Evident from this table, about 98 percent of the estimated engineering compliance costs accrue to the integrated and production segment of the industry, again explain by the fact that completion-related requirements contribute the bulk of the estimated engineering compliance costs (as well as estimated emissions reductions). About 17 percent of the total estimated engineering compliance costs (and about 18 percent of the costs accruing the integrated and production segment) are focused on small firms.

Table 7-21 Distribution of Estimated Proposed NSPS Compliance Costs Without Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

		Estimated Engineering Compliance Costs Without Estimated Revenues from Natural Gas Product Recovery (2008 dollars)				
Firm Type/Size	Number of Firms	Total	Mean	Median	Minimum	Maximum
Production and Integrated						
Small	79	82,293,903	1,041,695	221,467	3,210	10,054,401
Large	49	387,489,928	7,907,958	5,730,634	15,238	33,677,388
Subtotal	128	469,783,831	3,670,186	969,519	3,210	33,677,388
Pipeline						
Small	11	3,386	308	111	18	1,144
Large	36	1,486,929	41,304	3,821	37	900,696
Subtotal	47	1,490,314	31,709	2,263	18	900,696
Processing						
Small	39	476,165	12,209	1,882	188	276,343
Large	23	859,507	37,370	8,132	38	423,645
Subtotal	62	1,335,672	21,543	2,730	38	423,645
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	5,431,510	417,808	147,925	2,003	2,630,236
Subtotal	13	5,431,510	417,808	147,925	2,003	2,630,236
Total						
Small	**129**	**82,773,454**	**641,655**	**49,386**	**18**	**10,054,401**
Large	**121**	**395,267,874**	**3,266,677**	**57,220**	**37**	**33,677,388**
Total	**250**	**478,041,328**	**1,912,165**	**55,888**	**18**	**33,677,388**

These distributions are similar when the revenues from expected natural gas recovery are included (Table 7-22). About 21 percent of the total savings from the proposed NSPS is expected to accrue to small firms (about 19 percent of the savings to the integrated and production segment accrue to small firms). Note also in Table 7-22 that the pipeline and processing segments (and the pipeline/processing firms) are not expected to experience net cost savings (negative costs) from the proposed NSPS.

Table 7-22 Distribution of Estimated Proposed NSPS Compliance Costs With Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

		Estimated Engineering Compliance Costs With Estimated Revenues from Natural Gas Product Recovery (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Mean	Median	Minimum	Maximum
Production and Integrated						
Small	79	-5,065,551	-64,121	-13,729	-620,880	8,699
Large	49	-22,197,126	-453,003	-318,551	-2,072,384	423,760
Subtotal	128	-27,262,676	-212,990	-43,479	-2,072,384	423,760
Pipeline						
Small	11	2,303	209	76	12	779
Large	36	1,011,572	28,099	2,599	25	612,753
Subtotal	47	1,013,876	21,572	1,539	12	612,753
Processing						
Small	39	160,248	4,109	634	63	93,000
Large	23	289,258	12,576	2,737	13	142,573
Subtotal	62	449,506	7,250	919	13	142,573
Pipelines/Processing						
Small	0	---	---	---	---	---
Large	13	3,060,373	235,413	86,301	716	1,746,730
Subtotal	13	3,060,373	235,413	86,301	716	1,746,730
Total						
Small	**129**	**-4,902,999**	**-38,008**	**-2,520**	**-620,880**	**93,000**
Large	**121**	**-17,835,922**	**-147,404**	**634**	**-2,072,384**	**1,746,730**
Total	**250**	**-22,738,922**	**-90,956**	**22**	**-2,072,384**	**1,746,730**

Table 7-23 Summary of Sales Test Ratios, Without Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS

		Descriptive Statistics for Sales Test Ratio Without Estimated Revenues from Natural Gas Product Recovery (%)			
Firm Type/Size	Number of Firms	Mean	Median	Minimum	Maximum
Production and Integrated					
Small	79	2.18%	0.49%	0.01%	50.83%
Large	49	0.41%	0.28%	<0.01%	2.83%
Subtotal	128	1.50%	0.39%	<0.01%	50.83%
Pipeline					
Small	11	<0.01%	<0.01%	<0.01%	0.01%
Large	36	0.01%	<0.01%	<0.01%	0.06%
Subtotal	47	0.01%	<0.01%	<0.01%	0.06%
Processing					
Small	39	0.05%	0.01%	<0.01%	0.33%
Large	23	0.02%	0.01%	<0.01%	0.15%
Subtotal	62	0.04%	0.01%	<0.01%	0.33%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	<0.01%	<0.01%	<0.01%	0.01%
Subtotal	13	<0.01%	<0.01%	<0.01%	0.01%
Total					
Small	**129**	**1.34%**	**0.15%**	**<0.01%**	**50.83%**
Large	**121**	**0.17%**	**0.01%**	**<0.01%**	**2.83%**
Total	**250**	**0.78%**	**0.03%**	**<0.01%**	**50.83%**

The mean cost-sales ratio for all businesses when estimated product recovery is excluded from the analysis of the sample data is 0.78 percent, with a median ratio of 0.03 percent, a minimum of less than 0.01 percent, and a maximum of over 50 percent (Table 7-23). For small firms in the sample, the mean and median cost-sales ratios are 1.34 percent and 0.15 percent, respectively, with a minimum of less than 0.01 percent and a maximum of over 50 percent (Table 7-23). Each of these statistics indicates that, when considered in the aggregate, impacts are relatively higher on small firms than large firms when the estimated revenue from additional natural gas product recovery is excluded. However, as the next table shows, the reverse is true when these revenues are included.

Table 7-24 Summary of Sales Test Ratios, With Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS

		Descriptive Statistics for Sales Test Ratio With Estimated Revenues from Natural Gas Product Recovery (%)			
Firm Type/Size	Number of Firms	Mean	Median	Minimum	Maximum
Production and Integrated					
Small	79	-0.13%	-0.03%	-2.96%	<0.00%
Large	49	-0.02%	-0.02%	-0.17%	0.06%
Subtotal	128	-0.09%	-0.02%	-2.96%	0.06%
Pipeline					
Small	11	<0.00%	<0.01%	<0.01%	0.01%
Large	36	0.01%	<0.01%	<0.01%	0.04%
Subtotal	47	0.01%	<0.01%	<0.01%	0.04%
Processing					
Small	39	0.01%	<0.01%	<0.01%	0.05%
Large	23	<0.00%	<0.01%	<0.01%	0.05%
Subtotal	62	0.01%	<0.01%	<0.01%	0.05%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	<0.01%	<0.01%	<0.01%	0.01%
Subtotal	13	<0.01%	<0.01%	<0.01%	0.01%
Total					
Small	**129**	**-0.08%**	**-0.01%**	**-2.96%**	**0.05%**
Large	**121**	**-0.01%**	**<0.01%**	**-0.17%**	**0.06%**
Total	**250**	**-0.04%**	**<0.01%**	**-2.96%**	**0.06%**

The mean cost-sales ratio for all businesses when estimated product recovery is included is in the sample is -0.04 percent, with a median ratio of less than 0.01 percent, a minimum of -2.96 percent, and a maximum of 0.06 percent (Table 7-24). For small firms in the sample, the mean and median cost-sales ratios are -0.08 percent and -0.01 percent, respectively, with a minimum of -2.96 percent and a maximum of 0.05 percent (Table 7-24). Each of these statistics indicates that, when considered in the aggregate, impacts are small on small business when the estimated revenue from additional natural gas product recovery are included, the reverse of the conclusion found when these revenues are excluded.

Meanwhile, Table 7-25 presents the distribution of estimated cost-sales ratios for the small firms in our sample with and without including estimates of the expected natural gas product recover from implementing controls. When revenues estimates are included, all 129 firms (100 percent) have estimated cost-sales ratios less than 1 percent. While less than 1 percent, the highest cost-sales ratios for small firms in the sample experiencing impacts are largely driven by costs accruing to processing and pipeline firms. That said, the incremental costs imposed on firms that process natural gas or transport natural gas via pipelines are not estimated to create significant impacts on a cost-sales ratio basis at the firm-level.

Table 7-25 Impact Levels of Proposed NSPS on Small Firms as a Percent of Small Firms in Sample, With and Without Revenues from Additional Natural Gas Product Recovery

	Without Estimated Revenues from Natural Gas Product Recovery		With Estimated Revenues from Natural Gas Product Recovery	
Impact Level	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected
C/S Ratio less than 1%	109	84.5%	129	100.00%
C/S Ratio 1-3%	11	8.5%	0	0.00%
CS Ratio greater than 3%	9	7.0%	0	0.00%

When the estimated revenues from product recovery are not included in the analysis, 11 firms (about 9 percent) are estimated to have sales test ratios between 1 and 3 percent. Nine firms (about 7 percent) are estimated to have sales test ratios greater than 3 percent. These results noted, the exclusion of product recovery is somewhat artificial. While the mean engineering compliance costs and revenues estimates are valid, drawing on the means ignores the distribution around the mean estimates, which risks masking effects. Because of this risk, the following section offers a qualitative discussion of small entities with regard to obtaining REC services, the validity of the cost and performance of RECs for small firms, as well as offers a discussion about whether older equipment, which may be disproportionately owned and operated be smaller producers, would be affected by the proposed NSPS.

7.4.3.3 Small Entity Impact Analysis, Proposed NSPS, Additional Qualitative Discussion

3.5.3.3.1 Small Entities and Reduced Emissions Completions

Because REC requirements of the proposed NSPS are expected to contribute the large majority of engineering compliance costs, it is important to examine these requirements more closely in the context small entities. Important issues to resolve are the scale of REC costs within a drilling project, how the payment system for recovered natural gas functions, whether small entities pursue particular “niche” strategies that may influence the costs or performance in a way that makes the estimates costs and revenues invalid.

According to the most recent natural gas well cost data from EIA, the average cost of drilling and completing a producing natural gas well in 2007 was about $4.8 million (adjusted to 2008 dollars). This average includes lower cost wells that may be relatively shallow or are not hydraulically fractured. Hydraulically fractured wells in deep formations may cost up to $10 million. RECs contracted from a service provider are estimated to cost $33,200 (in 2008 dollars) or roughly 0.3%-0.7% of the typical cost of a drilling and completing a natural gas well. As this range does not include revenues expected from natural gas and hydrocarbon condensate recovery expected to offset REC implementation costs, REC costs likely represent a small increment of the overall burden of a drilling project.

To implement an REC, a service provider, which may itself be a small entity, is typically contracted to bring a set of equipment to the well pad temporarily to capture the stream that would otherwise be vented to the atmosphere. Typically, service providers are engaged in a long term drilling program in a particular basin covering multiple wells on multiple well pads. For gas captured and sold to the gathering system, Lease Automatic Custody Transfer (LACT) meters are normally read daily automatically, and sales transactions are typically settled at the end of the month. Invoices from service providers are generally delivered in 30-day increments during the well development time period, as well as at the end of the working contract for that well pad. The conclusion from the information, based on the available information, in most cases, the owner/operator incurs the REC cost within the same 30 day period that the owner/operator receives revenue as a result of the REC.

We assume small firms are performing RECs in CO and WY, as in many instances RECs are required under state regulation. In addition to State regulations, some companies are implementing RECs voluntarily such as through participation in the EPA Natural Gas STAR Program and the focus of recent press reports.

As described in more detail below, many small independent E&P companies often do not conduct any of the actual field work. These firms will typically contract the drilling, completion, testing, well design, environmental assessment, and maintenance. Therefore, we believe it is likely that small independent E&P firms will contract for RECs from service providers if required to perform RECs. An important reminder is that performing a REC is a straightforward and inexpensive extension of drilling, completion, and testing activities.

To the extent that very small firms may specialize in operating relatively few low-producing stripper wells, it is important to ask whether low-producing wells are likely candidates for re-fracturing/re-completion and, if so, whether the expected costs and revenues would be valid. These marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion. To the extent the marginal wells may be good candidates for re-fracturing/completion, the REC costs are valid estimates. The average REC cost is valid for RECs performed on any well, regardless of the operator size. The reason for this is that the REC service is contracted out to specialty service providers who charge daily rates for the REC equipment and workers. The cost is not related to any well characteristic.

Large operators may receive a discount for offering larger contracts which help a service provider guarantee that REC equipment will be utilized. However, we should note that the existence of a potential discount for larger contracts is based on a strong assumption; we do not have evidence to support this assumption. Since contracting REC equipment is analogous to contracting for drilling equipment, completion equipment, etc., the premium would likely be in the same range as other equipment contracted by small operators. Since the REC cost is a small portion of the overall well drilling and completion cost, the effect of any bulk discount disparity between large and small operators will be small, if in fact it does exist.

Although small operators may own the majority of marginal and stripper wells, they will make decisions based on economics just as any sized company would. For developing a new well, any sized company will expect a return on their investment meaning the potential for sufficient gas, condensate, and/or oil production to pay back their investment and generate a return that exceeds alternative investment opportunities. Therefore, small or large operators that are performing hydraulic fracture completions will experience the same distribution of REC performance. For refracturing an existing well, the well must be a good candidate to respond to the re-fracture/completion with a production increase that merits the investment in the re-fracture/completion.

Plugging and abandoning wells is complex and costly, so sustaining the productivity of wells is important for maximizing the exploitation of proven domestic resources. However, many marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion, which means they are likely unaffected by the proposed NSPS.

3.5.3.3.2 Age of Equipment and Proposed Regulations

Given a large fraction of domestic oil and natural gas production is produced from older and generally low productivity wells, it is important to examine whether the proposed requirements might present impediments to owners and operators of older equipment. The NSPS is a standard that applies to new or modified sources. Because of this, NSPS requirements target new or modified affected facilities or equipment, such as processing plants and compressors. While the requirements may apply to modifications of existing facilities, it is important to discuss well completion-related requirements aside from other requirements in the NSPS distinctly.

Excluding well completion requirements from the cost estimates, the non-completion NSPS requirements (related to equipment leaks at processing plants, reciprocating and centrifugal compressors, pneumatic controllers, and storage vessels) are estimated to require $27 million in annualized engineering costs. EPA also estimates that the annualized costs of these requirements will be mostly if not fully offset by revenues expected from natural gas recovery. EPA does not expect these requirements to disproportionately affect producers with older equipment. Meanwhile, the REC and emissions combustion requirements in the proposed NSPS relate to well completion activities at new hydraulically fractured natural gas wells and existing wells which are recompleted after being fractured or re-fractured. These requirements constitute the bulk of the expected engineering compliance expenditures (about $710 million in annualized costs) and expected revenues from natural gas product recovery (about $760 million in revenues, annually).

While age of the well and equipment may be an important factor for small and large producers in determining whether it is economical to fracture or re-fracture an existing well, this equipment is unlikely to be subject to the NSPS. To comply with completion-related requirements, producers are likely to rely heavily on portable and temporary completion equipment brought to the wellpad over a short period of time (a few days to a few weeks) to capture and combust emissions that are otherwise vented. The equipment at the wellhead—newly installed in the case of new well completions or already in place and operating in the case of existing wells—is not likely to be subject to the NSPS requirement.

7.4.3.4 Small Entity Impact Analysis, Proposed NSPS, Screening Analysis Conclusion

The number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to reduced emissions completion activities occur without a significant time lag between implementing the control and obtaining the recovered product unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions and recompletions occur over a short span of time, during which the additional product recovery is also accomplished.

7.4.4 Small Entity Economic Impact Analysis, Proposed NESHAP Amendments

The proposed NESHAP amendments will affect facilities operating three types of equipment: glycol dehydrators at production facilities, glycol dehydrators at transmission and compression facilities, and storage vessels. We identified likely affected facilities in the National Emissions Inventory (NEI) and estimated the number of newly required controls of each type that would be required by the NESHAP amendments for each facility. We then used available data sources to best identify the ultimate owner of the equipment that would likely require new controls and linked facility-level compliance cost estimates to firm-level employment and revenue data. These data were then used to calculate an estimated compliance costs to revenues ratio to identify small businesses that might be significantly impacted by the NESHAP.

While we were able to identify the owners all but 14 facilities likely to be affected, we could not obtain employment and revenue levels for all of these firms. Overall, we expect about 447 facilities to be affected, and these facilities are owned by an estimated 160 firms. We were unable to obtain financial information on 42 (26 percent) of these firms due to inadequate data. In some instances, firms are private, and financial data is not available. In other instance, firms may no longer exist, since NEI data are not updated continuously. From the ownership information and compliance cost estimates from the engineering analysis, we estimated total compliance cost per firm.

Of the 118 firms for which we have financial information, we identified 62 small firms and 56 large firms that would be affected by the NESHAP amendments. Annual compliance costs for small firms are estimated at $3.0 million (18 percent of the total compliance costs), and annual compliance costs for large firms are estimated at $10.7 million (67 percent of the total compliance costs). The facilities for which we were unable to identify the ultimate owners, employment, and revenue levels would have an estimated annual compliance cost of $2.3 million (15 percent of the total). All figures are in 2008 dollars.

The average estimated annualized compliance cost for the 62 small firms identified in the dataset is $48,000, while the mean annual revenue figure for the same firms is over $120 million, or less than 1 percent for a average sales-test ratio for all 62 firms (Table 7-26). The median sale-test ratio for these firms is smaller at 0.14 percent. Large firms are likely to see an average of $190,000 in annual compliance costs, whereas average revenue for these firms exceeds $30 billion since this set of firms includes many of the very large, integrated energy firms. For large firms, the average sales-test ratio is about 0.01 percent, and the median sales-test ratio is less than 0.01 percent (Table 7-26).

Table 7-26 Summary of Sales Test Ratios for Firms Affected by Proposed NESHAP Amendments

Firm Size	No. of Known Affected Firms	% of Total Known Affected Firms	Mean C/S Ratio	Median C/S Ratio	Min. C/S Ratio	Max. C/S Ratio
Small	62	53%	0.62%	0.14%	< 0.01%	6.2%
Large	56	47%	0.01%	< 0.01%	< 0.01%	0.4%
All	118	100%	0.34%	0.02%	< 0.01%	6.2%

Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile 10 firms (16 percent) are likely to have impacts greater than 1 percent (Table 7-27). Four of these 10 firms are likely to have impacts greater than 3 percent (Table 7-27) While these 10 firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211 (Table 7-27).

Table 7-27 Affected Small Firms as a Percent of Small Firms Nationwide, Proposed NESHAP amendments

Firm Size	Number of Small Firms Affected Nationwide	% of Small Firms Affected Nationwide	Affected Firms as a % of National Firms (6,427)
C/S Ratio less than 1%	52	83.9%	0.81%
C/S Ratio 1-3%	6	9.7%	0.09%
CS Ratio greater than 3%	4	6.5%	0.06%

Screening Analysis Conclusion: While there are significant impacts on small business, the analysis shows that a substantial number of small firms are not impacted. Based upon the analysis in this section, we presume there is no SISNOSE arising from the proposed NESHAP amendments.

7.5 References

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ORIGINAL ARTICLE

Long-Term Ozone Exposure and Mortality

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ABSTRACT

BACKGROUND

Although many studies have linked elevations in tropospheric ozone to adverse health outcomes, the effect of long-term exposure to ozone on air pollution–related mortality remains uncertain. We examined the potential contribution of exposure to ozone to the risk of death from cardiopulmonary causes and specifically to death from respiratory causes.

METHODS

Data from the study cohort of the American Cancer Society Cancer Prevention Study II were correlated with air-pollution data from 96 metropolitan statistical areas in the United States. Data were analyzed from 448,850 subjects, with 118,777 deaths in an 18-year follow-up period. Data on daily maximum ozone concentrations were obtained from April 1 to September 30 for the years 1977 through 2000. Data on concentrations of fine particulate matter (particles that are ≤2.5 μm in aerodynamic diameter [$PM_{2.5}$]) were obtained for the years 1999 and 2000. Associations between ozone concentrations and the risk of death were evaluated with the use of standard and multilevel Cox regression models.

RESULTS

In single-pollutant models, increased concentrations of either $PM_{2.5}$ or ozone were significantly associated with an increased risk of death from cardiopulmonary causes. In two-pollutant models, $PM_{2.5}$ was associated with the risk of death from cardiovascular causes, whereas ozone was associated with the risk of death from respiratory causes. The estimated relative risk of death from respiratory causes that was associated with an increment in ozone concentration of 10 ppb was 1.040 (95% confidence interval, 1.010 to 1.067). The association of ozone with the risk of death from respiratory causes was insensitive to adjustment for confounders and to the type of statistical model used.

CONCLUSIONS

In this large study, we were not able to detect an effect of ozone on the risk of death from cardiovascular causes when the concentration of $PM_{2.5}$ was taken into account. We did, however, demonstrate a significant increase in the risk of death from respiratory causes in association with an increase in ozone concentration.

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Studies conducted over the past 15 years have provided substantial evidence that long-term exposure to air pollution is a risk factor for cardiopulmonary disease and death.[1-5] Recent reviews of this literature suggest that fine particulate matter (particles that are ≤2.5 μm in aerodynamic diameter [$PM_{2.5}$]) has a primary role in these adverse health effects.[6,7] The particulate-matter component of air pollution includes complex mixtures of metals, black carbon, sulfates, nitrates, and other direct and indirect byproducts of incomplete combustion and high-temperature industrial processes.

Ozone is a single, well-defined pollutant, yet the effect of exposure to ozone on air pollution–related mortality remains inconclusive. Several studies have evaluated this issue, but they have been short-term studies,[8-10] have failed to show a statistically significant effect,[1,3] or have been based on limited mortality data.[11] Recent reviews by the Environmental Protection Agency (EPA)[12] and the National Research Council[13] have questioned the overall consistency of the available data correlating exposure to ozone and mortality. Similar conclusions about the evidence base for the long-term effects of ozone on mortality were drawn by a panel of experts in the United Kingdom.[14]

Nonetheless, previous studies have suggested that a measurable effect of ozone may exist, particularly with respect to the risk of death from cardiopulmonary causes. In one of the larger studies, ozone was significantly associated with death from cardiopulmonary causes[15] but not with death from ischemic heart disease. However, the estimated effect of ozone on the risk of death from cardiopulmonary causes in this study was attenuated when $PM_{2.5}$ was added to the analysis in copollutant models. On the basis of suggested effects of ozone on the risk of death from cardiopulmonary causes (which includes death from respiratory causes) but an absence of evidence for effects of ozone on the risk of death from ischemic heart disease, we hypothesized that ozone might have a primary effect on the risk of death from respiratory causes.

METHODS

HEALTH, MORTALITY, AND CONFOUNDING DATA

Our study used data from the American Cancer Society Cancer Prevention Study II (CPS II) cohort.[16] The CPS II cohort consists of more than 1.2 million participants who were enrolled by American Cancer Society volunteers between September 1982 and February 1983 in all 50 states, the District of Columbia, and Puerto Rico. Enrollment was restricted to persons who were at least 30 years of age living in households with at least one person 45 years of age or older. After providing written informed consent, the participants completed a confidential questionnaire that included questions on demographic characteristics, smoking history, alcohol use, diet, and education.[17] Deaths were ascertained until August 1988 by personal inquiries of family members by the volunteers and thereafter by linkage with the National Death Index. Through 1995, death certificates were obtained and coded for cause of death. Beginning in 1996, codes for cause of death were provided by the National Death Index.[18]

The study population for our analysis included only those participants in CPS II who resided in U.S. metropolitan statistical areas within the 48 contiguous states or the District of Columbia (according to their address at the time of enrollment) and for whom data were available from at least one pollution monitor within their metropolitan area. The study was approved by the Ottawa Hospital Research Ethics Board, Canada.

Data on "ecologic" risk factors at the level of the metropolitan area representing social variables (educational level, percentage of homes with air conditioning, percentage of the population who were nonwhite), economic variables (household income, unemployment, income disparity), access to medical care (number of physicians and hospital beds per capita), and meteorologic variables were obtained from the 1980 U.S. Census and other secondary sources (see the Supplementary Appendix, available with the full text of this article at NEJM.org). These ecologic risk factors, as well as the individual risk factors collected in the CPS II questionnaire, were assessed as potential confounders of the effects of ozone.[3,5,19,20]

ESTIMATES OF EXPOSURE TO AIR POLLUTION

Ozone data were obtained from 1977 (5 years before the identification of the CPS II cohort) through 2000 for all air-pollution monitors in the study metropolitan areas from the EPA's Aerometric Information Retrieval System. Ozone data at each monitoring site were collected on an hourly basis, and the daily maximum value for the site was determined. All available daily maximum values for the monitoring site were averaged over each quarter year. The quarterly average values were reported for each monitor only when at least 75% of daily observations for that quarter were available.

The averages of the second (April through June) and third (July through September) quarters were calculated for each monitor if both quarterly averages were available. The period from April through September was selected because ozone concentrations tend to be elevated during the warmer seasons and because fewer data were available for the cooler seasons.

The average of the second and third quarterly averages for each year was then computed for all the monitors within each metropolitan area to form a single annual time series of air-pollution measurements for each metropolitan area for the period from 1977 to 2000. In addition, a summary measure of long-term exposure to ambient warm-season ozone was defined as the average of annual time-series measurements during the entire period from 1977 to 2000. Individual measures of exposure to ozone were then defined by assigning the average for the metropolitan area to each cohort member residing in that area.

Data on exposure to $PM_{2.5}$ were also obtained from the Aerometric Information Retrieval System database for the 2-year period from 1999 to 2000 (data on $PM_{2.5}$ were not available before 1999 for most metropolitan areas).[5] The average concentrations of $PM_{2.5}$ were included in our analyses to distinguish the effect of particulates from that of ozone on outcomes.

STATISTICAL ANALYSIS

Standard and multilevel random-effects Cox proportional-hazard models were used to assess the risk of death in relation to exposures to pollution. The subjects were matched according to age (in years), sex, and race. A total of 20 variables with 44 terms were used to control for individual characteristics that might confound or modify the association between air pollution and death. These variables, which were considered to be of potential importance on the basis of previous studies, included individual risk factors for which data had been collected in the CPS II questionnaire. Seven ecologic covariates obtained from the 1980 U.S. Census (median household income, the proportion of persons living in households with an income below 125% of the poverty line, the percentage of persons over the age of 16 years who were unemployed, the percentage of adults with less than a high-school [12th-grade] education, the percentage of homes with air conditioning, the Gini coefficient of income inequality [ranging from 0 to 1, with 0 indicating an equal distribution of income and 1 indicating that one person has all the income and everyone else has no income[20]], and the percentage of persons who were white) were also included. These variables were included at two levels: as the average for the metropolitan statistical area and as the difference between the average for the ZIP Code of residence and the average for the metropolitan statistical area. Additional sensitivity analyses were undertaken for ecologic variables that were available for only a subgroup of the 96 metropolitan statistical areas (see the Supplementary Appendix). Models were estimated for either ozone or $PM_{2.5}$. In addition, models with both $PM_{2.5}$ and ozone were estimated.

In additional analyses, our basic Cox models were modified by incorporating an adjustment for community-level random effects, which allowed us to take into account residual variation in mortality among communities.[21] The baseline hazard function was modulated by a community-specific random variable representing the residual risk of death for subjects in that community after individual and ecologic risk factors had been controlled for (see the Supplementary Appendix).

A formal analysis was conducted to assess whether a threshold existed for the association between exposure to ozone and the risk of death (see the Supplementary Appendix). A standard threshold model was postulated in which there was no association between exposure to ozone and the risk of death below a specified threshold concentration and a linear association (on the logarithmic scale of the proportional-hazards model) above the threshold.

The question of whether specific time windows were associated with the health effects was investigated by subdividing the follow-up interval into four periods (1982 to 1988, 1989 to 1992, 1993 to 1996, and 1997 to 2000). Exposures were matched for each of these periods and also tested for a 10-year average on the basis of the 5-year follow-up period and the 5 years before the follow-up period (see the Supplementary Appendix).

RESULTS

The analytic cohort included 448,850 subjects residing in 96 metropolitan statistical areas (Fig. 1).

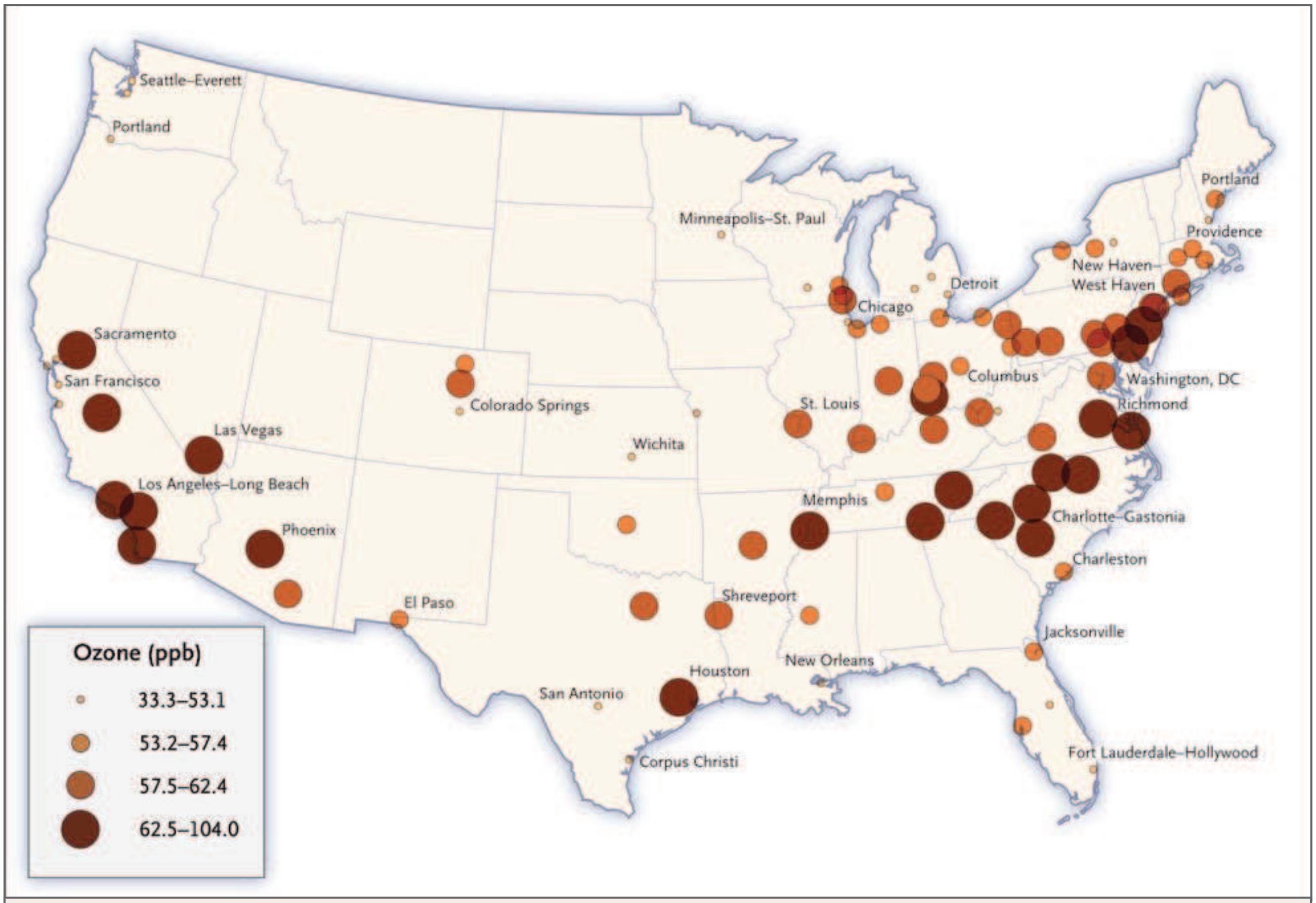

Figure 1. **Ozone Concentrations in the 96 Metropolitan Statistical Areas in Which Members of the American Cancer Society Cohort Resided in 1982.**

The average exposures were estimated from 1 to 57 monitoring sites within each metropolitan area from April 1 to September 30 for the years 1977 through 2000.

In 1980, the populations of these 96 areas ranged from 94,436 to 8,295,900. Data were available on the concentration of ambient ozone from all 96 areas and on the concentration of $PM_{2.5}$ from 86 areas. The average number of air-pollution monitors per metropolitan area was 11 (range, 1 to 57), and more than 80% of the areas had 6 or more monitors.

The average ozone concentration for each metropolitan area during the interval from 1977 to 2000 ranged from 33.3 ppb to 104.0 ppb (Fig. 1). The highest regional concentrations were in Southern California and the lowest in the Pacific Northwest and parts of the Great Plains. Moderately elevated concentrations were present in many areas of the East, Midwest, South, and Southwest.

The baseline characteristics of the study population, overall and as a function of exposure to ozone, are presented in Table 1. The mean age of the cohort was 56.6 years, 43.4% were men, 93.7% were white, 22.4% were current smokers, and 30.5% were former smokers. On the basis of estimates from 1980 Census data, 62.3% of homes had air conditioning at the time of initial data collection.

During the 18-year follow-up period (from initial CPS II data collection in 1982 through the end of follow-up in 2000), there were 118,777 deaths in the study cohort (Table 2). Of these, 58,775 were from cardiopulmonary causes, including 48,884 from cardiovascular causes (of which 27,642 were due to ischemic heart disease) and 9891 from respiratory causes.

In the single-pollutant models, exposure to ozone was not associated with the overall risk of death (relative risk, 1.001; 95% confidence interval [CI], 0.996 to 1.007) (Table 3). However, it was significantly correlated with an increase in the risk of death from cardiopulmonary causes. A

10-ppb increment in exposure to ozone elevated the relative risk of death from the following causes: cardiopulmonary causes (relative risk, 1.014; 95% CI, 1.007 to 1.022), cardiovascular causes (relative risk, 1.011; 95% CI, 1.003 to 1.023), ischemic heart disease (relative risk, 1.015; 95% CI, 1.003 to 1.026), and respiratory causes (relative risk, 1.029; 95% CI, 1.010 to 1.048).

Inclusion of the concentration of $PM_{2.5}$ measured in 1999 and 2000 as a copollutant (Table 3) attenuated the association with exposure to ozone for all the end points except death from respiratory causes, for which a significant correlation persisted (relative risk, 1.040; 95% CI, 1.013 to 1.067). The concentrations of ozone and $PM_{2.5}$ were positively correlated (r = 0.64 at the subject level and r = 0.56 at the metropolitan-area level), resulting in unstable risk estimates for both pollutants. The concentration of $PM_{2.5}$ remained significantly associated with death from cardio-

Table 1. Baseline Characteristics of the Study Population in the Entire Cohort and According to Exposure to Ozone.*

Variable	Entire Cohort (N = 448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N = 126,206)	53.2–57.4 ppb (N = 95,740)	57.5–62.4 ppb (N = 106,545)	62.5–104.0 ppb (N = 120,359)
No. of MSAs	96	24	24	24	24
No. of MSAs with data on $PM_{2.5}$	86	21	20	23	22
Concentration of $PM_{2.5}$ ($\mu g/m^3$)		11.9±2.5	13.1±2.9	14.7±2.1	15.4±3.2
Individual risk factors					
Age (yr)	56.6±10.5	56.7±10.4	56.4±10.7	56.3±10.4	56.9±10.5
Male sex (%)	43.4	43.5	43.1	43.5	43.2
White race (%)	93.7	94.3	95.1	93.9	91.8
Education (%)					
Less than high school	12.1	11.5	13.6	12.1	11.6
High school	30.6	30.2	33.6	32.1	27.4
Beyond high school	57.3	58.3	52.8	55.8	61.0
Smoking status					
Current smokers					
Percentage of subjects	22.4	22.0	23.5	22.2	21.9
No. of cigarettes/day	22.0±12.4	22.0±12.3	22.0±12.5	22.2±12.5	21.9±12.4
Duration of smoking (yr)	33.5±11.0	33.4±10.8	33.4±11.1	33.4±11.0	33.9±11.2
Started smoking <18 yr of age (%)	9.6	9.3	10.5	9.4	9.3
Started smoking ≥18 yr of age (%)	13.2	13.3	13.4	13.3	13.0
Former smokers					
Percentage of subjects	30.5	31.2	30.8	29.5	30.4
No. of cigarettes/day	21.6±14.7	21.6±14.6	22.2±15.1	21.6±14.6	21.3±14.6
Duration of smoking (yr)	22.2±12.6	22.1±12.5	22.6±12.6	22.0±12.5	22.4±12.7
Started smoking <18 yr of age (%)	11.9	11.8	12.7	11.5	11.8
Started smoking ≥18 yr of age (%)	18.5	19.3	17.9	17.9	18.5
Exposure to smoking (hr/day)	3.3±4.4	3.2±4.4	3.4±4.5	3.4±4.5	3.1±4.4
Pipe or cigar smoker only (%)	4.1	4.0	4.2	4.3	3.8
Marital status (%)					
Married	83.5	84.2	83.0	83.7	83.1
Single	3.6	3.4	4.0	3.8	3.2
Separated, divorced, or widowed	12.9	12.4	13.0	12.5	13.7

Table 1. (Continued.)

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
Body-mass index†	25.1±4.1	25.1±4.1	25.3±4.2	25.1±4.1	24.8±4.0
Level of occupational exposure to particulate matter (%)‡					
0	50.7	50.9	50.0	50.8	51.0
1	13.3	13.4	13.1	13.3	13.3
2	11.4	11.5	10.8	11.4	11.9
3	4.6	4.7	4.8	4.6	4.5
4	6.1	6.2	6.2	6.1	6.0
5	4.2	4.2	4.3	4.1	4.1
6	1.1	1.0	9.5	1.4	8.4
Not able to ascertain	8.6	8.2	1.2	8.4	0.9
Self-reported exposure to dust or fumes (%)	19.5	19.5	19.8	19.7	19.1
Level of dietary-fat consumption (%)§					
0	14.5	13.7	14.9	14.1	15.3
1	15.9	15.8	16.5	15.6	15.9
2	17.4	17.6	17.7	17.2	17.1
3	21.2	21.8	21.1	21.3	20.8
4	30.9	31.1	29.8	31.9	30.9
Level of dietary-fiber consumption (%)¶					
0	16.6	16.0	17.5	16.7	16.6
1	19.9	19.4	20.5	20.1	19.7
2	18.8	18.6	19.2	19.1	18.5
3	22.8	23.0	22.4	22.8	22.7
4	21.9	23.0	20.4	21.3	22.5
Alcohol consumption (%)					
Beer					
Drinks beer	22.9	24.3	23.2	22.9	21.4
Does not drink beer	9.7	9.5	9.3	9.5	10.2
No data	67.4	66.2	67.5	67.6	68.4
Liquor					
Drinks liquor	28.0	30.4	27.9	25.4	27.9
Does not drink liquor	8.8	8.4	8.5	10.1	9.2
No data	63.2	61.2	63.6	65.5	62.9
Wine					
Drinks wine	23.5	25.4	22.5	21.1	24.3
Does not drink wine	8.9	8.7	8.8	9.3	9.1
No data	67.6	65.9	68.7	69.6	66.6

Table 1. (Continued.)

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
Ecologic risk factors‖					
Nonwhite race (%)	11.6±16.8	10.5±16.4	9.3±15.5	10.2±16.0	15.9±18.3
Home with air conditioning (%)	62.3±27.0	55.4±31.2	59.4±24.0	65.3±24.8	69.1±24.3
High-school education or greater (%)	51.7±8.2	53.5±7.9	52.4±7.5	50.8±7.2	50.0±9.5
Unemployment rate (%)	11.7±3.1	12.1±3.4	11.3±2.6	11.3±2.9	11.8±3.4
Gini coefficient of income inequality**	0.37±0.04	0.37±0.05	0.37±0.04	0.37±0.04	0.38±0.04
Proportion of population with income <125% of poverty line	0.12±0.08	0.11±0.08	0.12±0.08	0.11±0.07	0.13±0.09
Annual household income (thousands of dollars)††	20.7±6.6	21.9±7.1	19.8±6.0	21.2±6.7	19.7±6.3

* MSA denotes metropolitan statistical area, and $PM_{2.5}$ fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Plus–minus values are means ±SD. Because of rounding, percentages may not total 100. All baseline characteristics included in the survival model are listed (age, sex, and race were included as stratification factors). The model also includes squared terms for the number of cigarettes smoked per day and the number of years of smoking for both current and former smokers and a squared term for body-mass index.

† The body-mass index is the weight in kilograms divided by the square of the height in meters.

‡ Occupational exposure to particulate matter increases with increasing index number. The index was calculated by assigning a relative level of exposure to $PM_{2.5}$ associated with a cohort member's job and industry. These assignments were performed by industrial hygienists on the basis of their knowledge of typical exposure patterns for each occupation and specific job.[22]

§ Dietary-fat consumption increases with increasing index number. Dietary information from cohort members was used to define the level of fat consumption according to five ordered categories.[20]

¶ Dietary-fiber consumption increases with increasing index number. Dietary information from cohort members was used to define the level of fiber consumption according to five ordered categories.[23]

‖ For the ecologic variables, the model included terms for influences at the level of the average for the metropolitan statistical area and at the level of the difference between the value for the ZIP Code of residence and the average for the metropolitan statistical area to represent between- and within-metropolitan area confounding influence. Some values for ecologic variables and individual variables differ, although they appear to measure the same risk factor. For example, for the entire cohort, the percentage of whites as listed under individual variables is 93.7, whereas the percentage of nonwhites as listed under ecologic variables is 11.6±16.8. This apparent contradiction is explained by the fact that the former is an exact figure based on the individual reports of the study participants in the CPS II questionnaire, whereas the latter is a mean (±SD) for the population based on Census estimates for each metropolitan statistical area.

** The Gini coefficient is a statistical dispersion measure used to calculate income inequality. The coefficient ranges from 0 to 1, with 0 indicating an equal distribution of income and 1 indicating that one person has all the income and everyone else has no income.[20] A coefficient of 0.37 indicates that on average there is a measurable inequality in the distribution of income among the different income groups within the MSAs.

†† Average household incomes for the cohort and for each quartile of ozone concentration were calculated from the median household income for the metropolitan statistical area.

pulmonary causes, cardiovascular causes, and ischemic heart disease when ozone was included in the model. The association of ozone concentrations with death from respiratory causes remained significant after adjustment for $PM_{2.5}$.

Risk estimates for ozone-related death from respiratory causes were insensitive to the use of a random-effects survival model allowing for spatial clustering within the metropolitan area and state of residence (Table 1S in the Supplementary Appendix). The association between increased ozone concentrations and increased risk of death from respiratory causes was also insensitive to adjustment for several ecologic variables considered individually (Table 2S in the Supplementary Appendix).

Subgroup analyses showed that environmental temperature and region of the country, but not sex, age at enrollment, body-mass index, education, or concentration of $PM_{2.5}$, significantly modified the effects of ozone on the risk of death from respiratory causes (Table 4).

Figure 2 illustrates the shape of the relation between exposure to ozone and death from re-

Table 2. Number of Deaths in the Entire Cohort and According to Exposure to Ozone.

Cause of Death	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
		number of deaths			
Any cause	118,777	32,957	25,642	27,782	32,396
Cardiopulmonary	58,775	16,328	12,621	13,544	16,282
Cardiovascular	48,884	13,605	10,657	11,280	13,342
Ischemic heart disease	27,642	7,714	6,384	6,276	7,268
Respiratory	9,891	2,723	1,964	2,264	2,940

Table 3. Relative Risk of Death Attributable to a 10-ppb Change in the Ambient Ozone Concentration.*

Cause of Death	Single-Pollutant Model†			Two-Pollutant Model‡	
	Ozone (96 MSAs)	Ozone (86 MSAs)	$PM_{2.5}$ (86 MSAs)	Ozone (86 MSAs)	$PM_{2.5}$ (86 MSAs)
	relative risk (95% CI)				
Any cause	1.001 (0.996–1.007)	1.001 (0.996–1.007)	1.048 (1.024–1.071)	0.989 (0.981–0.996)	1.080 (1.048–1.113)
Cardiopulmonary	1.014 (1.007–1.022)	1.016 (1.008–1.024)	1.129 (1.094–1.071)	0.992 (0.982–1.003)	1.153 (1.104–1.204)
Respiratory	1.029 (1.010–1.048)	1.027 (1.007–1.046)	1.031 (0.955–1.113)	1.040 (1.013–1.067)	0.927 (0.836–1.029)
Cardiovascular	1.011 (1.003–1.023)	1.014 (1.005–1.023)	1.150 (1.111–1.191)	0.983 (0.971–0.994)	1.206 (1.150–1.264)
Ischemic heart disease	1.015 (1.003–1.026)	1.017 (1.006–1.029)	1.211 (1.156–1.268)	0.973 (0.958–0.988)	1.306 (1.226–1.390)

* MSA denotes metropolitan statistical area, and $PM_{2.5}$ fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Ozone concentrations were measured from April to September during the years from 1977 to 2000, with follow-up from 1982 to 2000; changes in the concentration of $PM_{2.5}$ of 10 μg per cubic meter were recorded for members of the cohort in 1999 and 2000. These models are adjusted for all the individual and ecologic risk factors listed in Table 1. For the ecologic variables, the model included terms for influences at the level of the average for the metropolitan statistical area and at the level of the difference between the value for the ZIP Code of residence and the average for the metropolitan statistical area to represent between- and within-metropolitan area confounding influence. The risk of death was stratified according to age (in years), sex, and race.

† The single-pollutant models were based on 96 metropolitan statistical areas for which information on ozone was available and 86 metropolitan statistical areas for which information on both ozone and fine particulate matter was available.

‡ The two-pollutant models were based on 86 metropolitan statistical areas for which information on both ozone and fine particulate matter was available.

spiratory causes. There was limited evidence that a threshold model specification improved model fit as compared with a nonthreshold linear model (P=0.06) (Table 3S in the Supplementary Appendix).

Because air-pollution data from 1977 to 2000 were averaged, exposure values for persons who died during this period are based partly on data that were obtained after death had occurred. Further investigation by dividing this interval into specific time windows of exposure revealed no significant difference between the effects of earlier and later time windows within the period of follow-up. Allowing for a 10-year period of exposure to ozone (5 years of follow-up and 5 years before the follow-up period) did not appreciably alter the risk estimates (Table 4S in the Supplementary Appendix). Thus, when exposure values were matched more closely to the follow-up period and when exposure values were based on data obtained before the deaths, there was little change in the results.

DISCUSSION

Our principal finding is that ozone and $PM_{2.5}$ contributed independently to increased annual mortality rates in this large, U.S. cohort study in analyses that controlled for many individual and ecologic risk factors. In two-pollutant models that included ozone and $PM_{2.5}$, ozone was significantly associated only with death from respiratory causes.

For every 10-ppb increase in exposure to ozone, we observed an increase in the risk of death from respiratory causes of about 2.9% in single-pollutant models and 4% in two-pollutant models. Although this increase may appear moderate, the risk of dying from a respiratory cause is more than three times as great in the metropolitan areas with the highest ozone concentrations as in those with the lowest ozone concentrations. The effects of ozone on the risk of death from respiratory causes were insensitive to adjustment for individual, neighborhood, and metropolitan-area confounders or to differences in multilevel-model specifications.

There is biologic plausibility for a respiratory effect of ozone. In laboratory studies, ozone can increase airway inflammation[24] and can worsen pulmonary function and gas exchange.[25] In addition, exposure to elevated concentrations of tropospheric ozone has been associated with numerous adverse health effects, including the induction[26] and exacerbation[27,28] of asthma, pulmonary dysfunction,[29,30] and hospitalization for respiratory causes.[31]

Despite these observations, previous studies linking long-term exposure to ozone with death have been inconclusive. One cohort study conducted in the Midwest and eastern United States reported an inverse but nonsignificant association between ozone concentrations and mortality.[1] Subsequent reanalyses of this study replicated these findings but also suggested a positive association with exposure to ozone during warm seasons.[3] A study of approximately 6000 nonsmoking Seventh-Day Adventists living in Southern California showed elevated risks among men after long-term exposure to ozone,[11] but this finding was based on limited mortality data.

Previous studies using the CPS II cohort have also produced mixed results for ozone. An earlier examination based on a large sample of more than 500,000 people from 117 metropolitan areas and 8 years of follow-up indicated nonsignificant results for the relation between ozone and death from any cause and a significant inverse association between ozone and death from lung cancer. A positive association between death from cardiopulmonary causes and summertime exposure to ozone was observed in single-pollutant

Table 4. Relative Risk of Death from Respiratory Causes Attributable to a 10-ppb Change in the Ambient Ozone Concentration, Stratified According to Selected Risk Factors.*

Stratification Variable	% of Subjects in Stratum	Relative Risk (95% CI)	P Value of Effect Modification
Sex			0.11
Male	43	1.01 (0.99–1.04)	
Female	57	1.04 (1.03–1.07)	
Age at enrollment (yr)			0.74
<50	26	1.00 (0.90–1.11)	
50–65	54	1.03 (1.01–1.06)	
>65	20	1.02 (1.00–1.05)	
Education			0.48
High school or less	43	1.02 (1.00–1.05)	
Beyond high school	57	1.03 (1.01–1.06)	
Body-mass index†			0.96
<25.0	53	1.03 (1.01–1.06)	
25.0–29.9	36	1.03 (0.99–1.06)	
≥30.0	11	1.03 (0.96–1.10)	
$PM_{2.5}$ ($\mu g/m^3$)‡			0.38
<14.3	44	1.05 (1.01–1.09)	
>14.3	56	1.03 (1.00–1.05)	
Region§			0.05
Northeast	24.8	0.99 (0.92–1.07)	
Industrial Midwest	29.7	1.00 (0.91–1.09)	
Southeast	21.0	1.12 (1.05–1.19)	
Upper Midwest	5.2	1.14 (0.68–1.90)	
Northwest	7.7	1.06 (1.00–1.13)	
Southwest	3.9	1.21 (1.04–1.40)	
Southern California	7.8	1.01 (0.96–1.07)	
External temperature (°C)‡¶			0.01
<23.3	24	0.96 (0.90–1.01)	
>23.3 to <25.4	29	0.97 (0.87–1.08)	
>25.4 to <28.7	22	1.04 (0.92–1.16)	
>28.7	25	1.05 (1.03–1.08)	

* $PM_{2.5}$ denotes fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Ozone exposures for the cohort were measured from April to September during the years from 1977 to 2000, with follow-up from 1982 to 2000, with adjustment for individual risk factors, and with baseline hazard function stratified according to age (single-year groupings), sex, and race. These analyses are based on the single-pollutant model for ozone shown in Table 3. Because of rounding, percentages may not total 100.

† The body-mass index is the weight in kilograms divided by the square of the height in meters.

‡ Stratum cutoff is based on the median of the distribution at the metropolitan-area level, not at the subject level.

§ Definitions of regions are those used by the Environmental Protection Agency.[3]

¶ External temperature is calculated as the average daily maximum temperature recorded between April and September from 1977 to 2000.

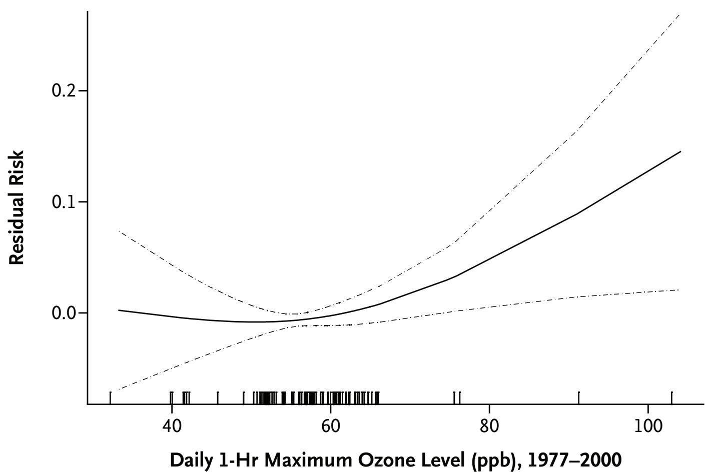

Figure 2. Exposure–Response Curve for the Relation between Exposure to Ozone and the Risk of Death from Respiratory Causes.

The curve is based on a natural spline with 2 df estimated from the residual relative risk of death within a metropolitan statistical area (MSA) according to a random-effects survival model. The dashed lines indicate the 95% confidence interval of fit, and the hash marks indicate the ozone levels of each of the 96 MSAs.

models, but the association with ozone was nonsignificant in two-pollutant models.[3] Further analyses based on 16 years of follow-up in 134 cities produced similarly elevated but nonsignificant associations that were suggestive of effects of summertime (July to September) exposure to ozone on death from cardiopulmonary causes.[5]

The increase in deaths from respiratory causes with increasing exposure to ozone may represent a combination of short-term effects of ozone on susceptible subjects who have influenza or pneumonia and long-term effects on the respiratory system caused by airway inflammation,[24] with subsequent loss of lung function in childhood,[32] young adulthood,[33,34] and possibly later life.[35] If exposure to ozone accelerates the natural loss of adult lung function with age, those exposed to higher concentrations of ozone would be at greater risk of dying from a respiratory-related syndrome.

In our two-pollutant models, the adjusted estimates of relative risk for the effect of ozone on the risk of death from cardiovascular causes were significantly less than 1.0, seemingly suggesting a protective effect. Such a beneficial influence of ozone, however, is unlikely from a biologic standpoint. The association of ozone with cardiovascular end points was sensitive to adjustment for exposure to $PM_{2.5}$, making it difficult to determine precisely the independent contributions of these copollutants to the risk of death. There was notable collinearity between the concentrations of ozone and $PM_{2.5}$.

Furthermore, measurement at central monitors probably represents population exposure to $PM_{2.5}$ more accurately than it represents exposure to ozone. Ozone concentration tends to vary spatially within cities more than does $PM_{2.5}$ concentration, because of scavenging of ozone by nitrogen oxide near roadways.[36] In the presence of a high density of local traffic, the measurement error is probably higher for exposure to ozone than for exposure to $PM_{2.5}$. The effects of ozone could therefore be confounded by the presence of $PM_{2.5}$ because of collinearity between the measurements of the two pollutants and the higher precision of measurements of $PM_{2.5}$.[37]

Measurements of $PM_{2.5}$ were available only for the end of the study follow-up period (1999 and 2000). Widespread collection of these data began only after the EPA adopted regulatory limits on such particulates in 1997. Since particulate air pollution has probably decreased in most metropolitan areas during the follow-up interval of our study, it is likely that we have underestimated the effect of $PM_{2.5}$ in our analysis.

A limitation of our study is that we were not able to account for the geographic mobility of the population during the follow-up period. We had information on home addresses for the CPS II cohort only at the time of initial enrollment in 1982 and 1983. Census data indicate that during the interval between 1982 and 2000, approximately 2 to 3% of the population moved from one state to another annually (with the highest rates in an age group younger than that of our study population).[38] However, any bias due to a failure to account for geographic mobility is likely to have attenuated, rather than exaggerated, the effects of ozone on mortality.

In summary, we investigated the effect of tropospheric ozone on the risk of death from any cause and cause-specific death in a large cohort, using data from 96 metropolitan statistical areas across the United States and controlling for the effect of particulate air pollutants. We were unable to detect a significant effect of exposure to ozone on the risk of death from cardiovascular causes when particulates were taken into account, but we did demonstrate a significant effect of exposure to ozone on the risk of death from respiratory causes.

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This article is dedicated to the memory of our coauthor and friend, Dr. Jeanne Calle, who died unexpectedly on February 17, 2009.

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United States Environmental Protection Agency

Ground-level Ozone
Health Effects

Ozone in the air we breathe can harm our health—typically on hot, sunny days when ozone can reach unhealthy levels. Even relatively low levels of ozone can cause health effects. People with lung disease, children, older adults, and people who are active outdoors may be particularly sensitive to ozone.

Children are at greatest risk from exposure to ozone because their lungs are still developing and they are more likely to be active outdoors when ozone levels are high, which increases their exposure. Children are also more likely than adults to have asthma.

Breathing ozone can trigger a variety of health problems including chest pain, coughing, throat irritation, and congestion. It can worsen bronchitis, emphysema, and asthma. Ground level ozone also can reduce lung function and inflame the linings of the lungs. Repeated exposure may permanently scar lung tissue.

Ozone can:

- Make it more difficult to breathe deeply and vigorously.
- Cause shortness of breath and pain when taking a deep breath.
- Cause coughing and sore or scratchy throat.
- Inflame and damage the airways.
- Aggravate lung diseases such as asthma, emphysema, and chronic bronchitis.
- Increase the frequency of asthma attacks.
- Make the lungs more susceptible to infection.
- Continue to damage the lungs even when the symptoms have disappeared.

These effects may lead to increased school absences, medication use, visits to doctors and emergency rooms, and hospital admissions. Research also indicates that ozone exposure may increase the risk of premature death from heart or lung disease.

Ozone is particularly likely to reach unhealthy levels on hot sunny days in urban environments. It is a major part of urban smog. Ozone can also be transported long distances by wind. For this reason, even rural areas can experience high ozone levels. And, in some cases, ozone can occur throughout the year in some southern and mountain regions. Learn more about the formation and transport of ground level ozone.

The AIRNow Web site provides daily air quality reports for many areas. These reports use the Air Quality Index (or AQI) to tell you how clean or polluted the air is. EnviroFlash, a free service, can alert you via email when your local air quality is a concern. Sign up at www.enviroflash.info.

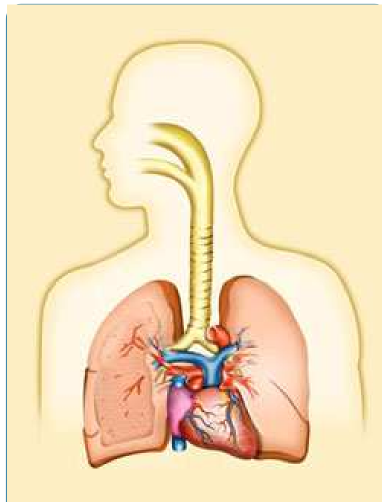
If you're a health care provider, visit AIRNow's Health Care Provider page for educational materials and trainings.

For more information on how EPA works to reduce ground level ozone, visit the Ozone Standards page.

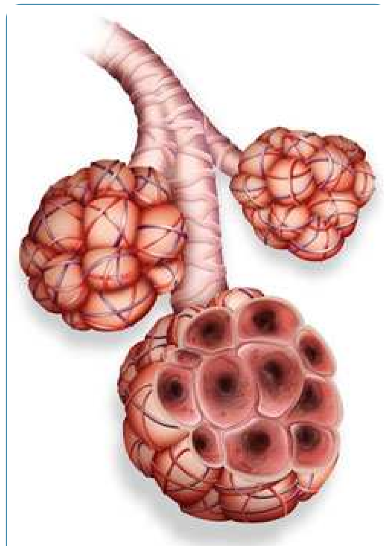
For more information on ground level ozone, health and the environment, visit:

- Ozone and Your Health (PDF) (2 pp, 2.5 MB) This short, colorful pamphlet tells who is at risk from exposure to ozone, what health effects are caused by ozone, and simple measures that can be taken to reduce health risk.
- Ozone: Good Up High, Bad Nearby (PDF) (2 pp, 1.3 MB) Ozone acts as a protective layer high above the earth, but it can be harmful to breathe. This publication provides basic information about ground level and high-altitude ozone.
- EPA's Air Quality Guide for Ozone Provides detailed information about what the Air Quality Index means. Helps determine ways to protect your family's health when ozone levels reach the unhealthy range, and ways you can help reduce ozone air pollution.
- Ozone and Your Patients' Health Training for Health Care Providers Designed for family practice doctors, pediatricians, nurse practitioners,

What are the effects of ozone?



Effects on the Airways. Ozone is a powerful oxidant that can irritate the air ways causing coughing, a burning sensation, wheezing and shortness of breath and it can aggravate asthma and other lung diseases.



Alveoli filled with trapped air. Ozone can cause the muscles in the airways to constrict, trapping air in the alveoli. This leads to wheezing and shortness of breath. In people with asthma it can result in asthma attacks.

asthma educators, and other medical professionals who counsel patients about asthma and respiratory symptoms.

- AIRNow Health Providers Information Provides information on how to help patients protect their health by reducing their exposure to air pollution.
- EPA's Asthma Web Site EPA's Communities in Action Asthma Initiative is a coordinated effort to reduce the burden of asthma and includes programs to address indoor and outdoor environments that cause, trigger or exacerbate asthma symptoms.
- Smog - Who Does it Hurt? (PDF) (10 pp, 819 KB) This 8-page booklet provides more detailed information than "Ozone and Your Health" about ozone health effects and how to avoid them.
- Summertime Safety: Keeping Kids Safe from Sun and Smog (PDF) (2 pp, 314 KB) This document discusses summer health hazards that pertain particularly to children and includes information about EPA's Air Quality Index and UV Index tools.

Airway Inflammation. With airway inflammation, there is an influx of white blood cells, increased mucous production, and fluid accumulation and retention. This causes the death and shedding of cells that line the airways and has been compared to the skin inflammation caused by sunburn.

Ozone and Your Patients' Health Training for Health Care Providers

Last updated on Thursday, November 01, 2012

Nitrogen Dioxide
Health

Current scientific evidence links short-term NO_2 exposures, ranging from 30 minutes to 24 hours, with adverse respiratory effects including airway inflammation in healthy people and increased respiratory symptoms in people with asthma.

Also, studies show a connection between breathing elevated short-term NO_2 concentrations, and increased visits to emergency departments and hospital admissions for respiratory issues, especially asthma.

NO_2 concentrations in vehicles and near roadways are appreciably higher than those measured at monitors in the current network. In fact, in-vehicle concentrations can be 2-3 times higher than measured at nearby area-wide monitors. Near-roadway (within about 50 meters) concentrations of NO_2 have been measured to be approximately 30 to 100% higher than concentrations away from roadways.

Individuals who spend time on or near major roadways can experience short-term NO_2 exposures considerably higher than measured by the current network. Approximately 16% of U.S housing units are located within 300 ft of a major highway, railroad, or airport (approximately 48 million people). This population likely includes a higher proportion of non-white and economically-disadvantaged people.

NO_2 exposure concentrations near roadways are of particular concern for susceptible individuals, including people with asthma asthmatics, children, and the elderly

The sum of nitric oxide (NO) and NO_2 is commonly called nitrogen oxides or NOx. Other oxides of nitrogen including nitrous acid and nitric acid are part of the nitrogen oxide family. While EPA's National Ambient Air Quality Standard (NAAQS) covers this entire family, NO_2 is the component of greatest interest and the indicator for the larger group of nitrogen oxides.

NOx react with ammonia, moisture, and other compounds to form small particles. These small particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death.

Ozone is formed when NOx and volatile organic compounds react in the presence of heat and sunlight. Children, the elderly, people with lung diseases such as asthma, and people who work or exercise outside are at risk for adverse effects from ozone. These include reduction in lung function and increased respiratory symptoms as well as respiratory-related emergency department visits, hospital admissions, and possibly premature deaths.

Emissions that lead to the formation of NO_2 generally also lead to the formation of other NOx. Emissions control measures leading to reductions in NO_2 can generally be expected to reduce population exposures to all gaseous NOx. This may have the important co-benefit of reducing the formation of ozone and fine particles both of which pose significant public health threats.

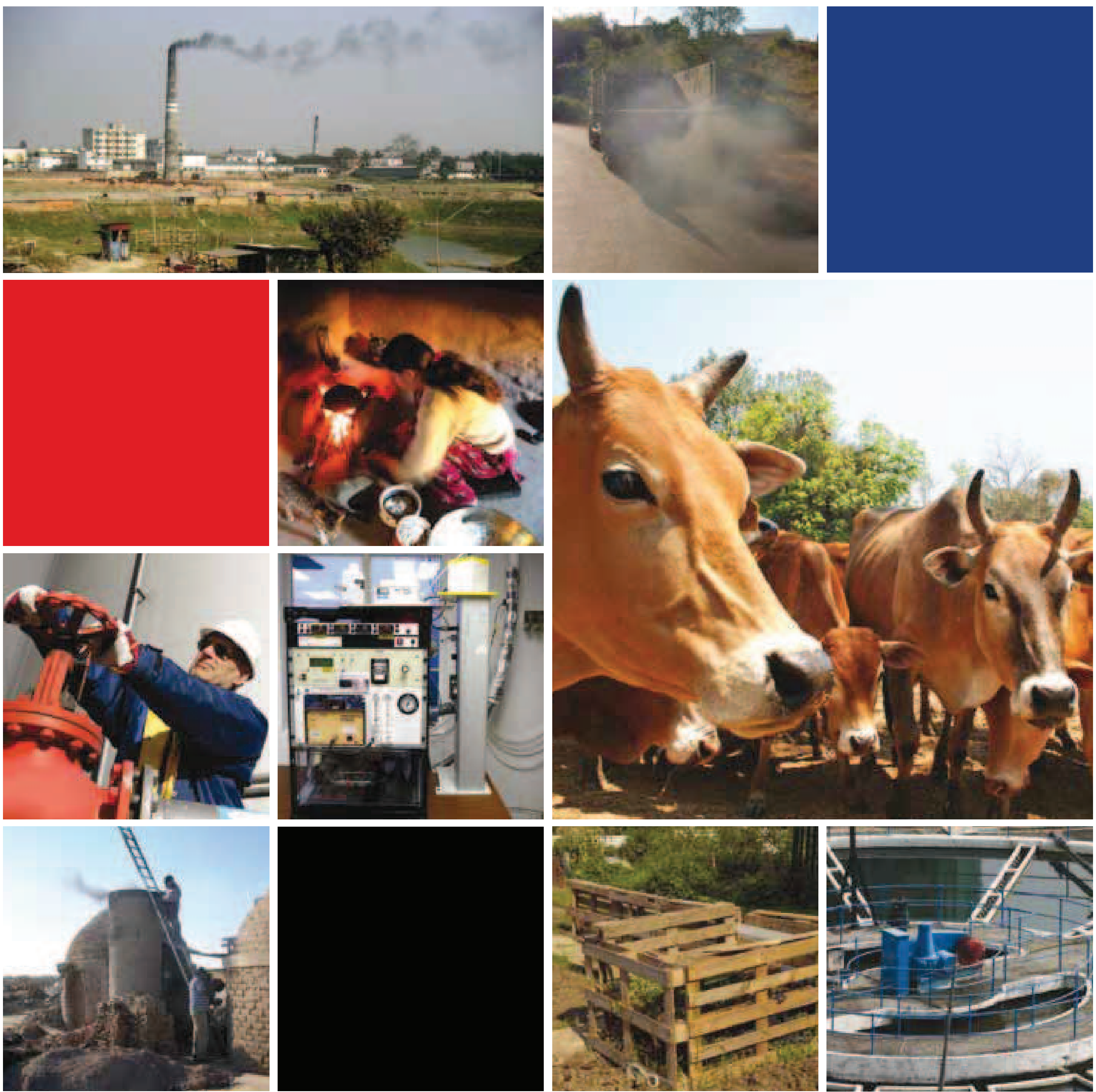
Last updated on Thursday, March 22, 2012

UNEP

World Meteorological Organization

Integrated Assessment of Black Carbon and Tropospheric Ozone

Summary for Decision Makers



A complete elaboration of the topics covered in this summary can be found in the Integrated Assessment of Black Carbon and Tropospheric Ozone report and in the fully referenced underlying research, analyses and reports.

For details of UNEP's regional and sub-regional areas referred to throughout this document see http://geodata.grid.unep.ch/extras/geosubregions.php.

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Disclaimers

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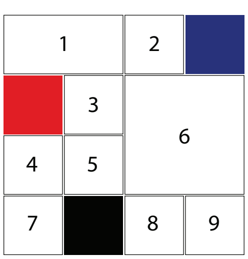

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Integrated Assessment of Black Carbon and Tropospheric Ozone

Summary for Decision Makers

Table of Contents

Main Messages

Scientific evidence and new analyses demonstrate that control of black carbon particles and tropospheric ozone through rapid implementation of proven emission reduction measures would have immediate and multiple benefits for human well-being.

Black carbon exists as particles in the atmosphere and is a major component of soot, it has significant human health and climate impacts. At ground level, ozone is an air pollutant harmful to human health and ecosystems, and throughout the troposphere, or lower atmosphere, is also a significant greenhouse gas. Ozone is not directly emitted, but is produced from emissions of precursors of which methane and carbon monoxide are of particular interest here.

THE CHALLENGE

1. **The climate is changing now, warming at the highest rate in polar and high-altitude regions.** Climate change, even in the near term, has the potential to trigger abrupt transitions such as the release of carbon from thawing permafrost and biodiversity loss. The world has warmed by about 0.8˚C from pre-industrial levels, as reported by the

Credit: Kevin Hicks

Traditional brick kilns in South Asia are a major source of black carbon. Improved kiln design in this region is significantly reducing emissions.

Intergovernmental Panel on Climate Change (IPCC). The Parties to the United Nations Framework Convention on Climate Change (UNFCCC) have agreed that warming should not exceed 2°C above pre-industrial levels.

2. **Black carbon and ozone in the lower atmosphere are harmful air pollutants that have substantial regional and global climate impacts.** They disturb tropical rainfall and regional circulation patterns such as the Asian monsoon, affecting the livelihoods of millions of people.

3. **Black carbon's darkening of snow and ice surfaces increases their absorption of sunlight, which, along with atmospheric heating, exacerbates melting of snow and ice around the world, including in the Arctic, the Himalayas and other glaciated and snow-covered regions.** This affects the water cycle and increases risks of flooding.

4. **Black carbon, a component of particulate matter, and ozone both lead to adverse impacts on human health leading to premature deaths worldwide. Ozone is also the most important air pollutant responsible for reducing crop yields, and thus affects food security.**

REDUCING EMISSIONS

5. **Reducing black carbon and tropospheric ozone now will slow the rate of climate change within the first half of this century. Climate benefits from reduced ozone are achieved by reducing emissions of some of its precursors, especially methane which is also a powerful greenhouse gas.** These short-lived climate forcers – methane, black carbon and ozone – are fundamentally different from longer-lived greenhouse gases, remaining in the atmosphere for only a relatively short time. Deep and immediate carbon dioxide reductions are required to protect long-term climate, as this cannot be achieved by addressing short-lived climate forcers.

6. **A small number of emission reduction measures targeting black carbon and ozone precursors could immediately begin to protect climate, public health, water and food security, and ecosystems.** Measures include the recovery of methane from coal, oil and gas extraction and transport, methane capture in waste management, use of clean-burning stoves for residential cooking, diesel particulate filters for vehicles and the banning of field burning of agricultural waste. Widespread implementation is achievable with existing technology but would require significant strategic investment and institutional arrangements.

7. **The identified measures complement but do not replace anticipated carbon dioxide reduction measures.** Major carbon dioxide reduction strategies mainly target the energy and large industrial sectors and therefore would not necessarily result in significant reductions in emissions of black carbon or the ozone precursors methane and carbon monoxide. Significant reduction of the short-lived climate forcers requires a specific strategy, as many are emitted from a large number of small sources.

BENEFITS OF EMISSION REDUCTIONS

8. **Full implementation of the identified measures would reduce future global warming by 0.5˚C (within a range of 0.2–0.7˚C, Figure 1).** If the measures were to be implemented by 2030, they could halve the potential increase in global temperature projected for 2050 compared to the Assessment's reference scenario based on current policies and energy and fuel projections. The rate of regional temperature increase would also be reduced.

9. **Both near-term and long-term strategies are essential to protect climate.** Reductions in near-term warming can be achieved by control of the short-lived climate forcers whereas carbon dioxide emission reductions, beginning now, are required to limit long-term climate change. Implementing both reduction strategies is needed to improve the chances of keeping the Earth's global mean temperature increase to within the UNFCCC 2˚C target.

10. **Full implementation of the identified measures would have substantial benefits in the Arctic, the Himalayas and other glaciated and snow-covered regions.** This could reduce warming in the Arctic in the next 30 years by about two-thirds compared to the projections of the Assessment's reference scenario. This substantially decreases the risk of changes in weather patterns and amplification of global warming resulting from changes in the Arctic. Regional benefits of the black carbon measures, such as their effects on snow- and ice-covered regions or regional rainfall patterns, are largely independent of their impact on global mean warming.

11. **Full implementation of the identified measures could avoid 2.4 million premature deaths (within a range of 0.7–4.6 million) and the loss of 52 million tonnes (within a range of 30–140 million tonnes), 1–4 per cent, of the global production of maize, rice, soybean and wheat each year (Figure 1).** The most substantial benefits will be felt immediately in or close to the regions where action is taken to reduce emissions, with the greatest health and crop benefits expected in Asia.

RESPONSES

12. The identified measures are all currently in use in different regions around the world to achieve a variety of environment and development objectives. **Much wider and more rapid implementation is required to achieve the full benefits identified in this Assessment.**

13. **Achieving widespread implementation of the identified measures would be most effective if it were country- and region-specific, and could be supported by the considerable existing body of knowledge and experience.** Accounting for near-term climate co-benefits could leverage additional action and funding on a wider international scale which would facilitate more rapid implementation of the measures. Many measures achieve cost savings over time. However, initial capital investment could be problematic in some countries, necessitating additional support and investment.

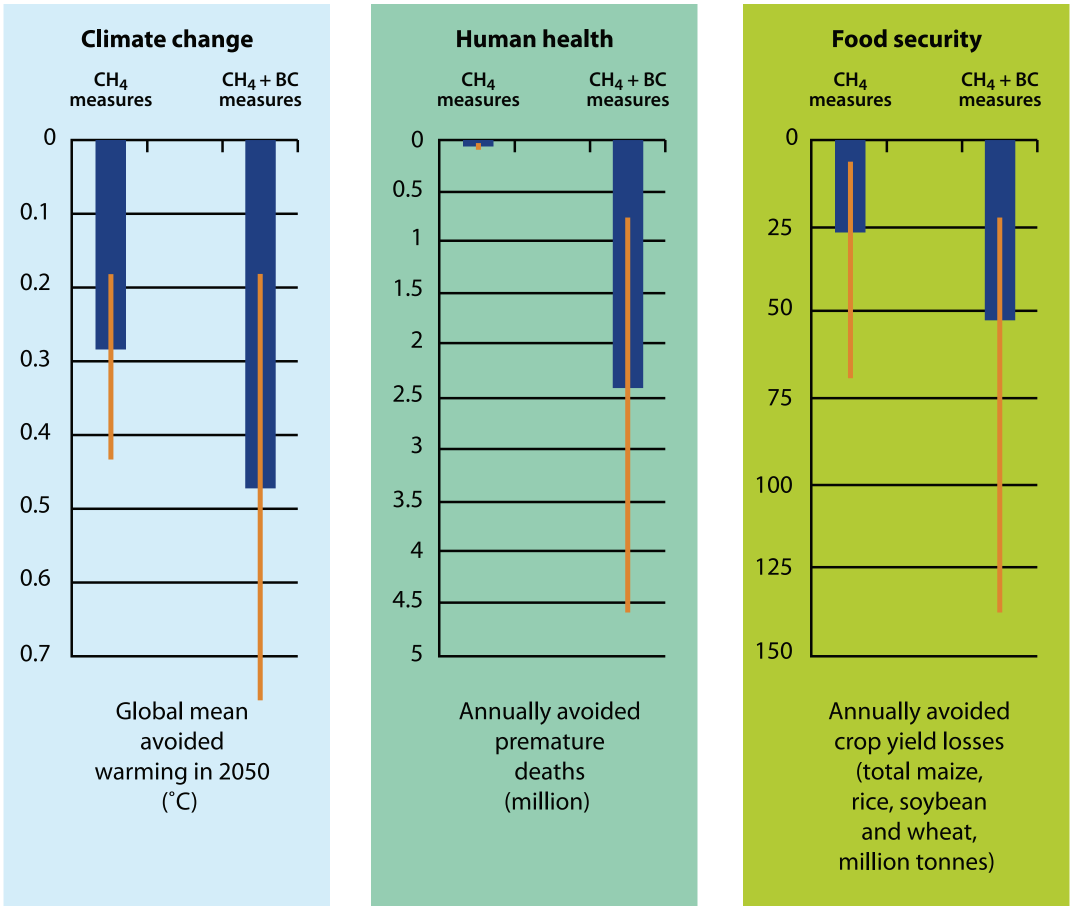


Figure 1. Global benefits from full implementation of the identified measures in 2030 compared to the reference scenario. The climate change benefit is estimated for a given year (2050) and human health and crop benefits are for 2030 and beyond.

14. **At national and sub-national scales many of the identified measures could be implemented under existing policies designed to address air quality and development concerns. Improved cooperation within and between regions would enhance widespread implementation and address transboundary climate and air quality issues.** International policy and financing instruments to address the co-benefits of reducing emissions of short-lived climate forcers need development and strengthening. Supporting and extending existing relevant regional arrangements may provide an opportunity for more effective cooperation, implementation and assessment as well as additional monitoring and research.

15. **The Assessment concludes that there is confidence that immediate and multiple benefits will be realized upon implementation of the identified measures.** The degree of confidence varies according to pollutant, impact and region. For example, there is higher confidence in the effect of methane measures on global temperatures than in the effect of black carbon measures, especially where these relate to the burning of biomass. There is also high confidence that benefits will be realized for human health from reducing particles, including black carbon, and to crop yields from reducing tropospheric ozone concentrations. Given the scientific complexity of the issues, further research is required to optimize near-term strategies in different regions and to evaluate the cost-benefit ratio for individual measures.

Introduction

Black carbon (BC, Box 1) and tropospheric ozone (O_3, Box 2) are harmful air pollutants that also contribute to climate change. In recent years, scientific understanding of how BC and O_3 affect climate and public health has significantly improved. This has catalysed a demand for information and action from governments, civil society and other stakeholders. The United Nations (UN) has been requested to urgently provide science-based advice on action to reduce the impacts of these pollutants[1].

The United Nations Environment Programme (UNEP), in consultation with partners, initiated an assessment designed to provide an interface between knowledge and action, science and policy, and to provide a scientifically credible basis for informed decision-making. The result is a comprehensive analysis of drivers of emissions, trends in concentrations, and impacts on climate, human health and ecosystems of BC, tropospheric O_3 and its precursors. BC, tropospheric O_3 and methane (CH_4) are often referred to as short-lived climate forcers (SLCFs) as they have a short lifetime in the atmosphere (days to about a decade) relative to carbon dioxide (CO_2).

The Assessment is an integrated analysis of multiple co-emitted pollutants reflecting the fact that these pollutants are not emitted in isolation (Boxes 1 and 2). The Assessment determined that under current policies, emissions of BC and O_3 precursors are expected globally either to increase or to remain roughly constant unless further mitigation action is taken.

The Integrated Assessment of Black Carbon and Tropospheric Ozone convened more than 50 authors to assess the state of science and existing policy options for addressing these pollutants. The Assessment team examined policy responses, developed an outlook to 2070 illustrating the benefits of political decisions made today and the risks to climate, human health and crop yields over the next decades if action is delayed. Placing a premium on robust science and analysis, the Assessment was driven by four main policy-relevant questions:

- Which measures are likely to provide significant combined climate and air-quality benefits?
- How much can implementation of the identified measures reduce the rate of global mean temperature increase by mid-century?
- What are the multiple climate, health and crop-yield benefits that would be achieved by implementing the measures?
- By what mechanisms could the measures be rapidly implemented?

In order to answer these questions, the Assessment team determined that new analyses were needed. The Assessment therefore relies on published literature as much as possible and on new simulations by two independent climate-chemistry-aerosol models: one developed and run by the NASA-Goddard Institute for Space Studies (GISS) and the other developed by the Max Planck Institute in Hamburg, Germany (ECHAM), and run at the Joint Research Centre of the European Commission in Ispra, Italy. The specific measures and emission estimates for use in developing this Assessment were selected using the International Institute for Applied Systems Analysis Greenhouse Gas and Air Pollution Interactions and Synergies (IIASA GAINS) model. For a more detailed description of the modelling see Chapter 1.

[1] The Anchorage Declaration of 24 April 2009, adopted by the Indigenous People's Global Summit on Climate Change; the Tromsø Declaration of 29 April 2009, adopted by the Sixth Ministerial Meeting of the Arctic Council and the 8th Session of the Permanent Forum on Indigenous Issues under the United Nations Economic and Social Council (May 2009) called on UNEP to conduct a fast track assessment of short-term drivers of climate change, specifically BC, with a view to initiating the negotiation of an international agreement to reduce emissions of BC. A need to take rapid action to address significant climate forcing agents other than CO_2, such as BC, was reflected in the 2009 declaration of the G8 leaders (Responsible Leadership for a Sustainable Future, L'Aquila, Italy, 2009).

Box 1: What is black carbon?

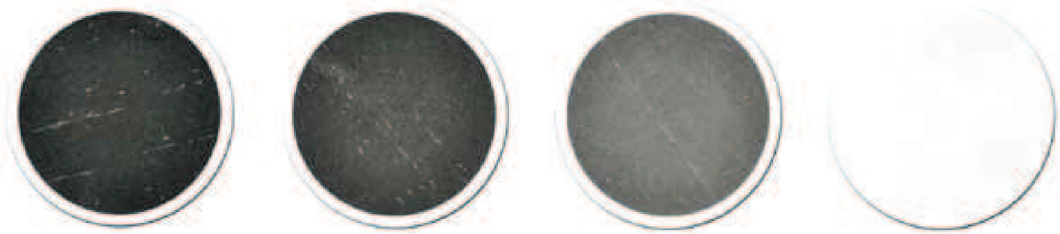
Black carbon (BC) exists as particles in the atmosphere and is a major component of soot. BC is not a greenhouse gas. Instead it warms the atmosphere by intercepting sunlight and absorbing it. BC and other particles are emitted from many common sources, such as cars and trucks, residential stoves, forest fires and some industrial facilities. BC particles have a strong warming effect in the atmosphere, darken snow when it is deposited, and influence cloud formation. Other particles may have a cooling effect in the atmosphere and all particles influence clouds. In addition to having an impact on climate, anthropogenic particles are also known to have a negative impact on human health.

Black carbon results from the incomplete combustion of fossil fuels, wood and other biomass. Complete combustion would turn all carbon in the fuel into carbon dioxide (CO_2). In practice, combustion is never complete and CO_2, carbon monoxide (CO), volatile organic compounds (VOCs), organic carbon (OC) particles and BC particles are all formed. There is a close relationship between emissions of BC (a warming agent) and OC (a cooling agent). They are always co-emitted, but in different proportions for different sources. Similarly, mitigation measures will have varying effects on the BC/OC mix.

The black in BC refers to the fact that these particles absorb visible light. This absorption leads to a disturbance of the planetary radiation balance and eventually to warming. The contribution to warming of 1 gramme of BC seen over a period of 100 years has been estimated to be anything from 100 to 2 000 times higher than that of 1 gramme of CO_2. An important aspect of BC particles is that their lifetime in the atmosphere is short, days to weeks, and so emission reductions have an immediate benefit for climate and health.

Haze with high particulate matter concentrations containing BC and OC, such as this over the Bay of Bengal, is widespread in many regions.

High emitting vehicles are a significant source of black carbon and other pollutants in many countries.



Credit: Luisa Molina

No retrofit system
Uncontrolled Diesel Exhaust
(Level 1)

Old technlogy
Little black carbon removal
Little ultrafine PM removal
Does not remove lube oil ash

Retrofitted with
Diesel Oxidation Catalyst (DOC)
(Level 1)

Old technlogy
Little black carbon removal
Little ultrafine PM removal
Does not remove lube oil ash

Retrofitted with
Partial Filter
(Level 2)

Little black carbon removal
Little ultrafine PM removal
Does not remove lube oil ash

Retrofitted with
Diesel Particulate Filter (DPF)
(Level 3)

New Technology
Used on all new trucks since 2007
>85% black carbon removal
>85% ultrafine removal
>85% lube oil ash removal

Some of the largest emission reductions are obtained using diesel particle filters on high emitting vehicles. The exhibits above are actual particulate matter (PM) collection samples from an engine testing laboratory (International Council of Clean Transportation (ICCT)).

Box 2: What is tropospheric ozone?

Ozone (O_3) is a reactive gas that exists in two layers of the atmosphere: the stratosphere (the upper layer) and the troposphere (ground level to ~10–15 km). In the stratosphere, O_3 is considered to be beneficial as it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, at ground level, it is an air pollutant harmful to human health and ecosystems, and it is a major component of urban smog. In the troposphere, O_3 is also a significant greenhouse gas. The threefold increase of the O_3 concentration in the northern hemisphere during the past 100 years has made it the third most important contributor to the human enhancement of the global greenhouse effect, after CO_2 and CH_4.

In the troposphere, O_3 is formed by the action of sunlight on O_3 precursors that have natural and anthropogenic sources. These precursors are CH_4, nitrogen oxides (NO_X), VOCs and CO. It is important to understand that reductions in both CH_4 and CO emissions have the potential to substantially reduce O_3 concentrations and reduce global warming. In contrast, reducing VOCs would clearly be beneficial but has a small impact on the global scale, while reducing NO_X has multiple additional effects that result in its net impact on climate being minimal.

Credit: Luisa Molina

Credit: Warren Gretz/DOE/NREL

Tropospheric ozone is a major constituent of urban smog, left Tokyo, Japan; right Denver, Colorado, USA

Limiting Near-Term Climate Changes and Improving Air Quality

Identifying effective response measures

The Assessment identified those measures most likely to provide combined benefits, taking into account the fact that BC and O_3 precursors are co-emitted with different gases and particles, some of which cause warming and some of which, such as organic carbon (OC) and sulphur dioxide (SO_2) lead to cooling. The selection criterion was that the measure had to be likely to reduce global climate change and also provide air quality benefits, so-called win-win measures. Those measures that provided a benefit for air quality but increased warming were not included in the selected measures. For example, measures that primarily reduce emissions of SO_2 were not included.

The identified measures (Table 1) were chosen from a subset of about 2 000 separate measures that can be applied to sources in IIASA's GAINS model. The selection was based on the net influence on warming, estimated using the metric Global Warming Potential (GWP), of all of the gases and particles that are affected by the measure. The selection gives a useful indication of the potential for realizing a win for climate. All emission reduction measures were assumed to benefit air quality by reducing particulate matter and/or O_3 concentrations.

This selection process identified a relatively small set of measures which nevertheless provide about 90 per cent of the climate benefit compared to the implementation of all 2 000 measures in GAINS. The final analysis of the benefits for temperature, human health and crop yields considered the emissions of all substances resulting from the full implementation of the identified measures through the two global composition-climate models GISS and ECHAM (see Chapter 4). One hundred per cent implementation of the measures globally was used to illustrate the existing potential to reduce climate and air quality impacts, but this does not make any assumptions regarding the feasibility of full implementation everywhere. A discussion of the challenges involved in widespread implementation of the measures follows after the potential benefit has been demonstrated.

Achieving large emission reductions

The packages of policy measures in Table 1 were compared to a reference scenario (Table 2). Figure 2 shows the effect of the packages of policy measures and the reference scenario relative to 2005 emissions.

There is tremendous regional variability in how emissions are projected to change by the year 2030 under the reference scenario. Emissions of CH_4 – a major O_3 precursor and a potent greenhouse gas – are expected to increase in the future (Figure 2). This increase will occur despite current and planned regulations, in large part due to anticipated economic growth and the increase in fossil fuel production projected to accompany it. In contrast, global emissions of BC and accompanying co-emitted pollutants are expected to remain relatively constant through to 2030. Regionally, reductions in BC emissions are expected due to tighter standards on road transport and more efficient combustion replacing use of biofuels in the residential and commercial sectors,

Table 1. Measures that improve climate change mitigation and air quality and have a large emission reduction potential

Measure[1]	Sector
CH_4 measures	
Extended pre-mine degasification and recovery and oxidation of CH_4 from ventilation air from coal mines	Extraction and transport of fossil fuel
Extended recovery and utilization, rather than venting, of associated gas and improved control of unintended fugitive emissions from the production of oil and natural gas	
Reduced gas leakage from long-distance transmission pipelines	
Separation and treatment of biodegradable municipal waste through recycling, composting and anaerobic digestion as well as landfill gas collection with combustion/utilization	Waste management
Upgrading primary wastewater treatment to secondary/tertiary treatment with gas recovery and overflow control	
Control of CH_4 emissions from livestock, mainly through farm-scale anaerobic digestion of manure from cattle and pigs	Agriculture
Intermittent aeration of continuously flooded rice paddies	
BC measures (affecting BC and other co-emitted compounds)	
Diesel particle filters for road and off-road vehicles	Transport
Elimination of high-emitting vehicles in road and off-road transport	
Replacing coal by coal briquettes in cooking and heating stoves	Residential
Pellet stoves and boilers, using fuel made from recycled wood waste or sawdust, to replace current wood-burning technologies in the residential sector in industrialized countries	
Introduction of clean-burning biomass stoves for cooking and heating in developing countries[2, 3]	
Substitution of clean-burning cookstoves using modern fuels for traditional biomass cookstoves in developing countries[2, 3]	
Replacing traditional brick kilns with vertical shaft kilns and Hoffman kilns	Industry
Replacing traditional coke ovens with modern recovery ovens, including the improvement of end-of-pipe abatement measures in developing countries	
Ban of open field burning of agricultural waste[2]	Agriculture

1 There are measures other than those identified in the table that could be implemented. For example, electric cars would have a similar impact to diesel particulate filters but these have not yet been widely introduced; forest fire controls could also be important but are not included due to the difficulty in establishing the proportion of fires that are anthropogenic.
2 Motivated in part by its effect on health and regional climate, including areas of ice and snow.
3 For cookstoves, given their importance for BC emissions, two alternative measures are included.

although these are offset to some extent by increased activity and economic growth. The regional BC emission trends, therefore, vary significantly, with emissions expected to decrease in North America and Europe, Latin America and the Caribbean, and in Northeast Asia, Southeast Asia and the Pacific, and to increase in Africa and South, West and Central Asia.

The full implementation of the selected measures by 2030 leads to significant reductions of SLCF emissions relative to current emissions or to the 2030 emissions in the reference scenario (Figure 2). It also reduces a high proportion of the emissions relative to the maximum reduction from the implementation of all 2 000 or so measures in the GAINS model. The measures designed to reduce BC also have a considerable impact on OC, total fine particulate matter ($PM_{2.5}$) and CO emissions, removing more than half the total anthropogenic emissions. The largest BC emission reductions are obtained through measures controlling incomplete combustion of biomass and diesel particle filters.

The major sources of CO_2 are different from those emitting most BC, OC, CH_4 and CO. Even in the few cases where there is overlap, such as diesel vehicles, the particle filters that reduce BC, OC and CO have minimal effect on CO_2. The measures to reduce CO_2 over the next 20 years (Table 2) therefore hardly affect the emissions of BC, OC or CO. The influence of the CH_4 and BC measures is thus the same regardless of whether the CO_2 measures are imposed or not.

Reducing near-term global warming

The Earth is projected to continue the rapid warming of the past several decades and, without additional mitigation efforts, under the reference scenario global mean temperatures are projected to rise about a further 1.3°C (with a range of 0.8–2.0°C) by the middle of this century, bringing the total warming from pre-industrial levels to about 2.2°C (Figure 3). The Assessment shows that the measures targeted to reduce emissions of BC and CH_4 could greatly reduce global mean warming rates over the next few decades (Figure 3). Figure 1 shows that over half of the reduced global mean warming is achieved by the CH_4 measures and the remainder by BC measures. The greater confidence in the effect of CH_4 measures on warming is reflected in the narrower range of estimates.

When all measures are fully implemented, warming during the 2030s relative to the present day is only half as much as if no measures had been implemented. In contrast, even a fairly aggressive strategy to reduce CO_2 emissions under the CO_2 measures scenario does little to mitigate warming over the next 20–30 years. In fact, sulphate particles, reflecting particles that offset some of the committed warming for the short time they are in the atmosphere, are derived from SO_2 that is co-emitted with CO_2 in some of the highest-emitting activities, including coal burning in large-scale combustion such as in power plants. Hence, CO_2 measures alone may temporarily enhance near-term warming as sulphates are reduced (Figure 3;

Table 2. Policy packages used in the Assessment

Scenario	Description[1]
Reference	Based on energy and fuel projections of the International Energy Agency (IEA) *World Energy Outlook 2009* and incorporating all presently agreed policies affecting emissions
CH_4 measures	Reference scenario plus the CH_4 measures
BC measures	Reference scenario plus the BC measures (the BC measures affect many pollutants, especially BC, OC, and CO)
CH_4 + BC measures	Reference scenario plus the CH_4 and BC measures
CO_2 measures	Emissions modelled using the assumptions of the IEA *World Energy Outlook 2009* 450 Scenario[2] and the IIASA GAINS database. Includes CO_2 measures only. The CO_2 measures affect other emissions, especially SO_2[3]
CO_2 + CH_4 + BC measures	CO_2 measures plus CH_4 and BC measures

1 In all scenarios, trends in all pollutant emissions are included through 2030, after which only trends in CO_2 are included.
2 The 450 Scenario is designed to keep total forcing due to long-lived greenhouse gases (including CH_4 in this case) at a level equivalent to 450 ppm CO_2 by the end of the century.
3 Emissions of SO_2 are reduced by 35–40 per cent by implementing CO_2 measures. A further reduction in sulphur emissions would be beneficial to health but would increase global warming. This is because sulphate particles cool the Earth by reflecting sunlight back to space.

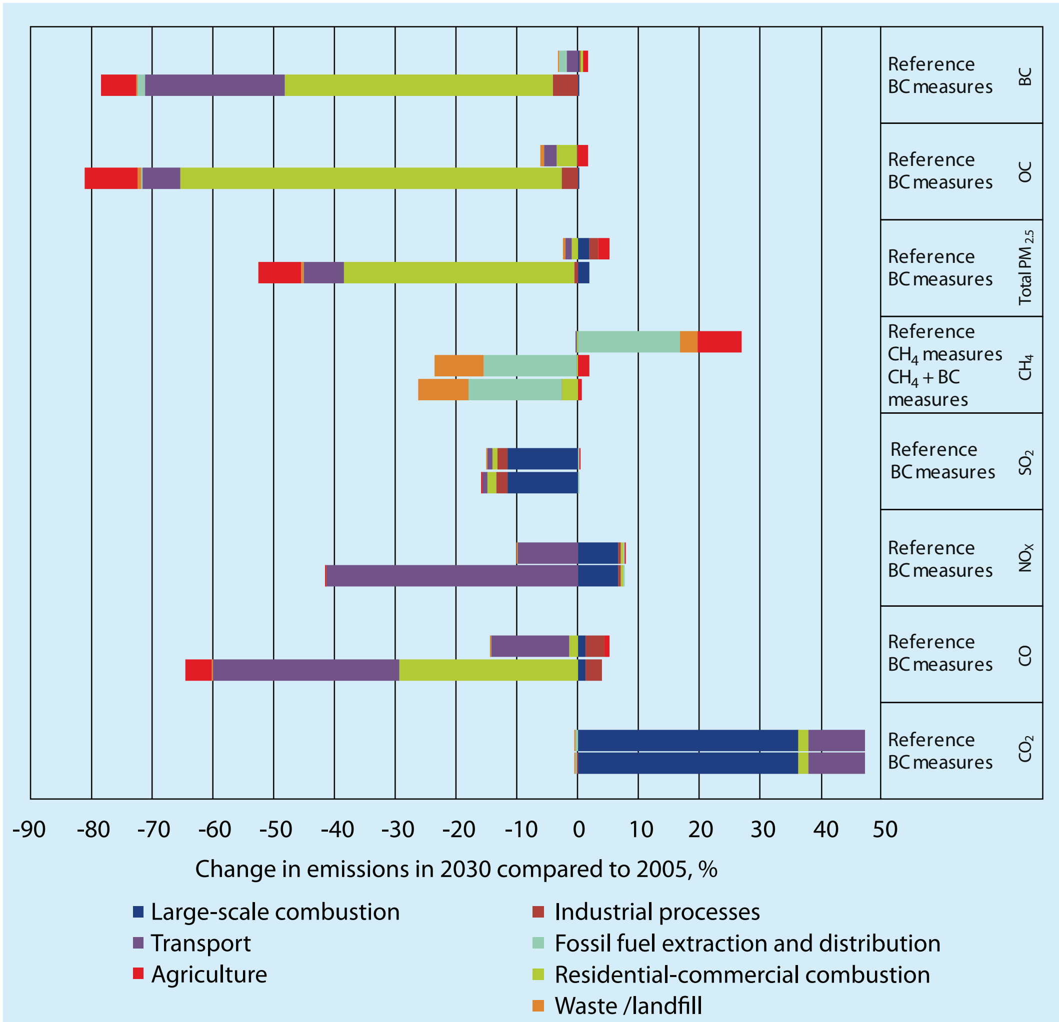


Figure 2. Percentage change in anthropogenic emissions of the indicated pollutants in 2030 relative to 2005 for the reference, CH_4, BC and CH_4 + BC measures scenarios. The CH_4 measures have minimal effect on emissions of anything other than CH_4. The identified BC measures reduce a large proportion of total BC, OC and CO emissions. SO_2 and CO_2 emissions are hardly affected by the identified CH_4 and BC measures, while NO_X and other $PM_{2.5}$ emissions are affected by the BC measures.

temperatures in the CO_2 measures scenario are slightly higher than those in the reference scenario during the period 2020–2040).

The CO_2 measures clearly lead to long-term benefits, with a dramatically lower warming rate in 2070 than under the scenario with only near-term CH_4 + BC measures. Owing to the long residence time of CO_2 in the atmosphere, these long-term benefits will only be achieved if CO_2 emission reductions are brought in quickly. In essence, the near-term CH_4 and BC measures examined in this Assessment are effectively decoupled from the CO_2 measures both in that they target different source sectors and in that their impacts on climate change take place over different timescales.

Near-term warming may occur in sensitive regions and could cause essentially irreversible changes, such as loss of Arctic land-ice, release of CH_4 or CO_2 from Arctic permafrost and species loss. Indeed, the projected warming in the reference scenario is greater in the Arctic than globally. Reducing the near-term rate of warming hence decreases the risk of irreversible transitions that could influence the global climate system for centuries.

Staying within critical temperature thresholds

Adoption of the near-term emission control measures described in this Assessment, together with measures to reduce CO_2 emissions, would greatly improve the chances of keeping Earth's temperature increase to less than 2˚C relative to pre-industrial levels (Figure 3). With the CO_2 measures alone, warming exceeds 2˚C before 2050. Even with both the CO_2 measures and CH_4 measures envisioned under the same IEA 450 Scenario, warming exceeds 2˚C in the 2060s (see Chapter 5). However, the combination of CO_2, CH_4, and BC measures holds the temperature increase below 2˚C until around 2070. While CO_2 emission reductions even larger than those in the CO_2 measures scenario would of course mitigate more warming, actual CO_2 emissions over the past decade have consistently exceeded the most pessimistic emission scenarios of the IPCC. Thus, it seems unlikely that reductions more stringent than those in the CO_2 measures scenario will take place during the next 20 years.

Examining the more stringent UNFCCC 1.5˚C threshold, the CO_2 measures scenario exceeds this by 2030, whereas the near-term measures proposed in the Assessment delay that exceedance until after 2040. Again, while substantially deeper early reductions in CO_2 emissions than those in the CO_2 measures scenario could also delay the crossing of the 1.5˚C temperature threshold, such reductions would undoubtedly be even more difficult to achieve. However, adoption of the Assessment's near-term measures (CH_4 + BC) along with the CO_2 reductions would provide

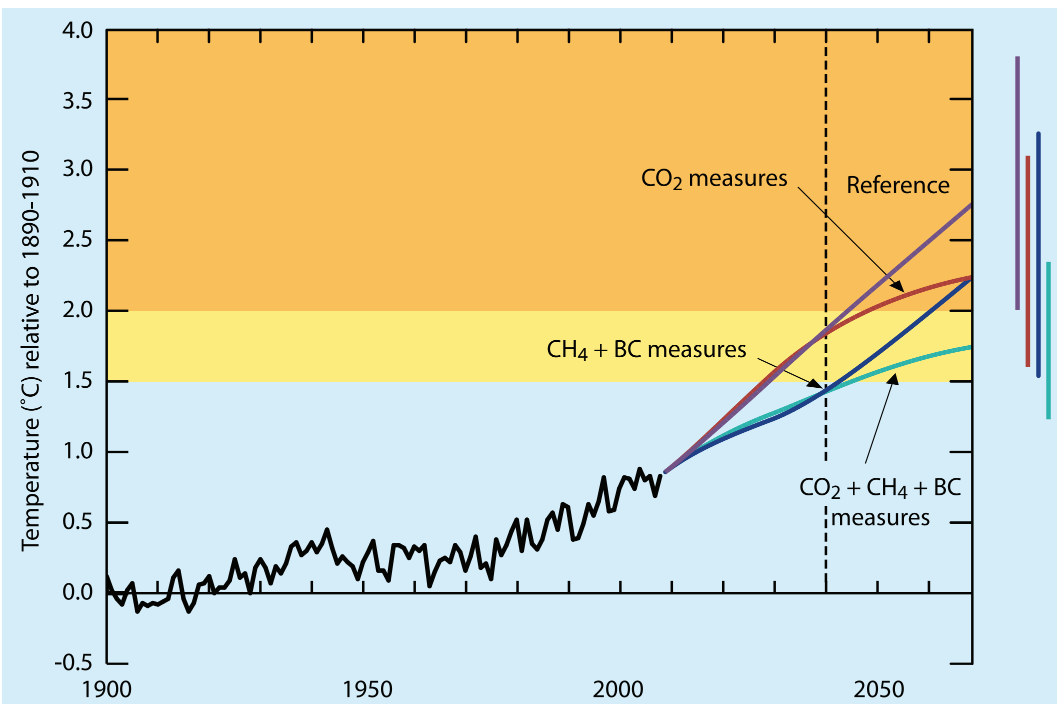


Figure 3. Observed deviation of temperature to 2009 and projections under various scenarios. Immediate implementation of the identified BC and CH_4 measures, together with measures to reduce CO_2 emissions, would greatly improve the chances of keeping Earth's temperature increase to less than 2˚C relative to pre-industrial levels. The bulk of the benefits of CH_4 and BC measure are realized by 2040 (dashed line).

Explanatory notes: Actual mean temperature observations through 2009, and projected under various scenarios thereafter, are shown relative to the 1890–1910 mean temperature. Estimated ranges for 2070 are shown in the bars on the right. A portion of the uncertainty is common to all scenarios, so that overlapping ranges do not mean there is no difference, for example, if climate sensitivity is large, it is large regardless of the scenario, so temperatures in all scenarios would be towards the high-end of their ranges.

a substantial chance of keeping the Earth's temperature increase below 1.5˚C for the next 30 years.

Benefits of early implementation

There would clearly be much less warming during 2020–2060 were the measures implemented earlier rather than later (Figure 4). Hence there is a substantial near-term climate benefit in accelerating implementation of the identified measures even if some of these might eventually be adopted owing to general air-quality and development concerns. Clearly the earlier implementation will also have significant additional human health and crop-yield benefits.

Accelerated adoption of the identified measures has only a modest effect on long-term climate change in comparison with waiting 20 years, however (Figure 4). This reinforces the conclusion that reducing emissions of O_3 precursors and BC can have substantial benefits in the near term, but that mitigating long-term climate change depends on reducing emissions of long-lived greenhouse gases such as CO_2.

Regional climate benefits

While global mean temperatures provide some indication of climate impacts, temperature changes can vary dramatically from place to place even in response to relatively uniform forcing from long-lived greenhouse gases. Figure 5 shows that warming is projected to increase for all regions with some variation under the reference scenario, while the Assessment's measures provide the benefit of reduced warming in all regions.

Climate change also encompasses more than just temperature changes. Precipitation, melting rates of snow and ice, wind patterns, and clouds are all affected, and these in turn have an impact on human well-being by influencing factors such as water availability, agriculture and land use.

Both O_3 and BC, as well as other particles, can influence many of the processes that lead to the formation of clouds and precipitation. They alter surface temperatures, affecting evaporation. By absorbing sunlight in the atmosphere, O_3 and especially BC can affect cloud formation, rainfall and weather patterns. They can change wind patterns by affecting the regional temperature contrasts that drive the winds, influencing where rain and snow fall. While some aspects of these effects are local, they can also affect temperature, cloudiness, and precipitation far away from the emission sources. The regional changes in all these aspects of climate will be significant, but are currently not well quantified.

Tropical rainfall patterns and the Asian monsoon

Several detailed studies of the Asian monsoon suggest that regional forcing by absorbing particles substantially alters precipitation patterns (as explained in the previous section). The fact that both O_3 and particle changes are predominantly in the northern hemisphere means that they cause temperature gradients between the two hemispheres that influence rainfall patterns throughout the tropics. Implementation of the measures analysed in this Assessment would substantially decrease the regional atmospheric heating by particles (Figure 6), and are hence very likely to reduce regional shifts in precipitation. As the reductions of atmospheric forcing are greatest over the Indian sub-continent and other parts of Asia, the emission reductions may have a substantial effect on the Asian monsoon, mitigating disruption of traditional rainfall patterns. However, results from global climate models are not yet robust for the magnitude or timing of monsoon shifts resulting from either greenhouse gas increases or changes in absorbing particles. Nonetheless, results from climate models provide examples of the type of change that might be expected. Shifts in the timing and strength of precipitation can have significant impacts on human well-being because of changes in water

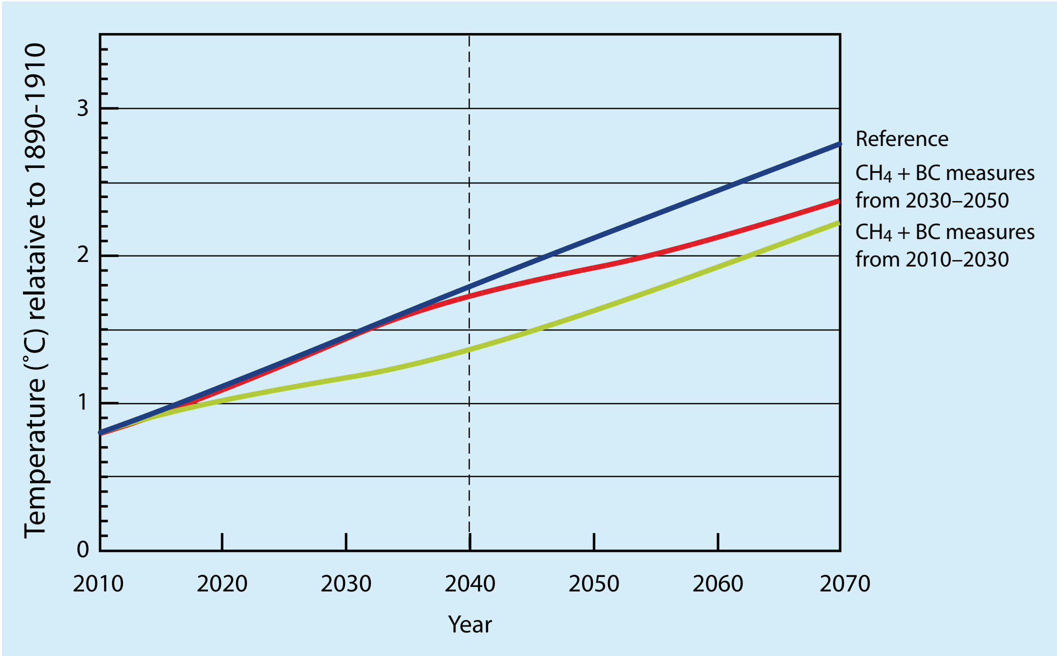


Figure 4. Projected global mean temperature changes for the reference scenario and for the CH_4 and BC measures scenario with emission reductions starting immediately or delayed by 20 years.

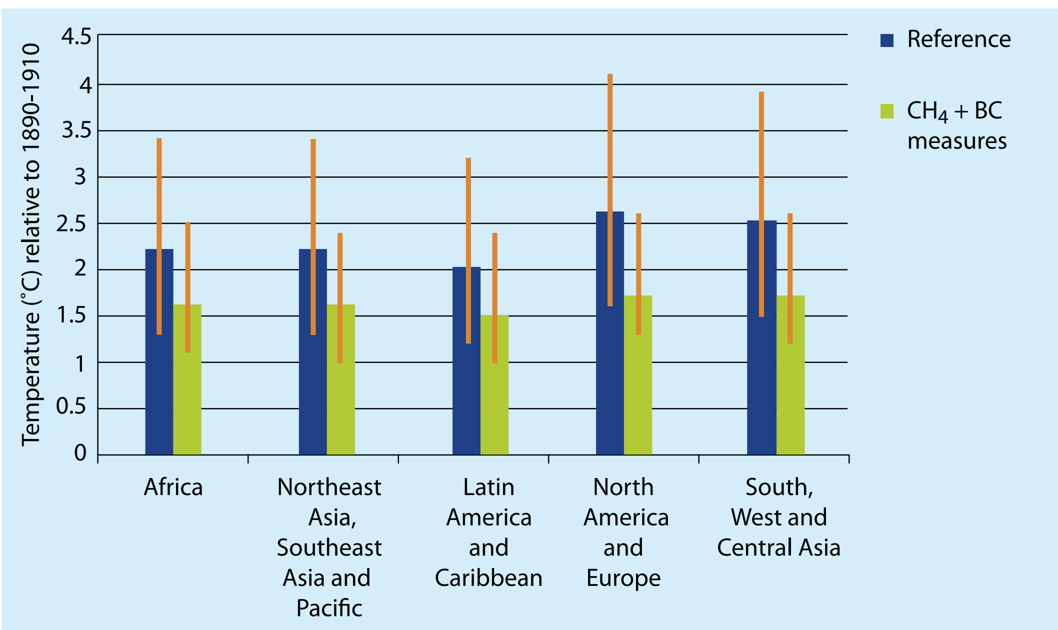


Figure 5. Comparison of regional mean warming over land (°C) showing the change in 2070 compared with 2005 for the reference scenario (Table 2) and the CH_4 + BC measures scenario. The lines on each bar show the range of estimates.

supply and agricultural productivity, drought and flooding. The results shown in Figure 6 suggest that implementation of the BC measures could also lead to a considerable reduction in the disruption of traditional rainfall patterns in Africa.

Decreased warming in polar and other glaciated regions

Implementation of the measures would substantially slow, but not halt, the current rapid pace of temperature rise and other changes already occurring at the poles and high-altitude glaciated regions, and the reduced warming in these regions would likely be greater than that seen globally. The large benefits occur in part because the snow/ice darkening effect of BC is substantially greater than the cooling effect of reflective particles co-emitted with BC, leading to greater warming impacts in these areas than in areas without snow and ice cover.

Studies in the Arctic indicate that it is highly sensitive both to local pollutant emissions and those transported from sources close to the Arctic, as well as to the climate impact of pollutants in the mid-latitudes of the northern hemisphere. Much of the need for implementation lies within Europe and North America. The identified measures could reduce warming in the Arctic by about 0.7°C (with a range of 0.2–1.3°C) in 2040. This is nearly two-thirds of the estimated 1.1°C (with a range of 0.7–1.7°C) warming projected for the Arctic under the reference scenario, and should substantially decrease the risk of global impacts from changes in this sensitive region, such as sea ice loss, which affects global albedo, and permafrost melt. Although not identified as a measure for use in this Assessment, the control of boreal forest fires may also be important in reducing impacts in the Arctic.

The Antarctic is a far less studied region in terms of SLCF impacts. However, there are studies demonstrating BC deposition even in central portions of the continent, and reductions in O_3 and CH_4 should slow warming in places like the Antarctic Peninsula, currently the spot on the globe showing the most rapid temperature rise of all.

The Himalayas and the Tibetan Plateau are regions where BC is likely to have serious impacts. In the high valleys of the Himalayas, for example, BC levels can be as high as in

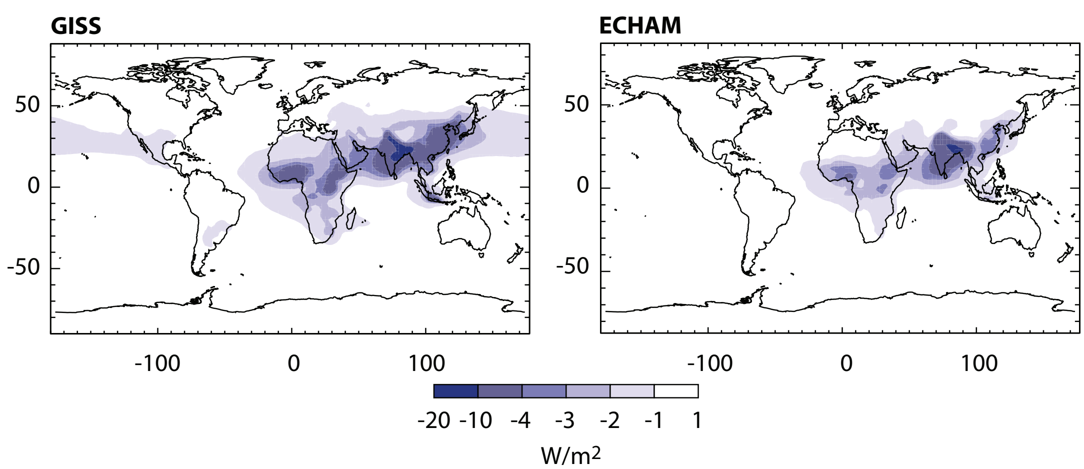


Figure 6. Change in atmospheric energy absorption (Watts per square metre, W/m² as annual mean), an important factor driving tropical rainfall and the monsoons resulting from implementation of BC measures. The changes in absorption of energy by the atmosphere are linked with changes in regional circulation and precipitation patterns, leading to increased precipitation in some regions and decreases in others. BC solar absorption increases the energy input to the atmosphere by as much as 5–15 per cent, with the BC measures removing the bulk of that heating. Results are shown for two independent models to highlight the similarity in the projections of where large regional decreases would occur.

a mid-sized city. Reducing emissions from local sources and those carried by long-range transport should lower glacial melt in these regions, decreasing the risk of impacts such as catastrophic glacial lake outbursts.

Benefits of the measures for human health

Fine particulate matter (measured as $PM_{2.5}$, which includes BC) and ground-level O_3 damage human health. $PM_{2.5}$ causes premature deaths primarily from heart disease and lung cancer, and O_3 exposure causes deaths primarily from respiratory illness. The health benefit estimates in the Assessment are limited to changes in these specific causes of death and include uncertainty in the estimation methods. However, these pollutants also contribute significantly to other health impacts including acute and chronic bronchitis and other respiratory illness, non-fatal heart attacks, low birth weight and results in increased emergency room visits and hospital admissions, as well as loss of work and school days.

Under the reference scenario, that is, without implementation of the identified measures, changes in concentrations of $PM_{2.5}$ and O_3 in 2030, relative to 2005, would have substantial effects globally on premature deaths related to air pollution. By region, premature deaths from outdoor pollution are projected to change in line with emissions. The latter are expected to decrease significantly over North America and Europe due to implementation of the existing and expected legislation. Over Africa and Latin America and the Caribbean, the number of premature deaths from these pollutants is expected to show modest changes under the reference scenario (Figure 7). Over Northeast Asia, Southeast Asia and Pacific, premature deaths are projected to decrease substantially due to reductions in $PM_{2.5}$ in some areas. However, in South, West and Central Asia, premature deaths are projected to rise significantly due to growth in emissions.

In contrast to the reference scenario, full implementation of the measures identified in the Assessment would substantially improve air quality and reduce premature deaths globally due to significant reductions in indoor and outdoor air pollution. The reductions in $PM_{2.5}$ concentrations resulting from the BC measures would, by 2030, avoid an estimated 0.7–4.6 million annual premature deaths due to outdoor air pollution (Figure 1).

Regionally, implementation of the identified measures would lead to greatly improved air quality and fewer premature deaths, especially in Asia (Figure 7). In fact, more than 80 per cent of the health benefits of implementing all measures occur in Asia. The benefits are large enough for all the worsening trends in human health due to outdoor air pollution to be reversed and turned into improvements, relative to 2005. In Africa, the benefit is substantial, although not as great as in Asia.

Benefits of the measures for crop yields

Ozone is toxic to plants. A vast body of literature describes experiments and observations showing the substantial effects of O_3 on visible leaf health, growth and productivity for a large number of crops, trees and other plants. Ozone also affects vegetation composition and diversity. Globally, the full implementation of CH_4 measures results in significant reductions in O_3 concentrations leading to avoided yield losses of about 25 million tonnes of four staple crops each year. The implementation of the BC measures would account for about a further 25 million tonnes of avoided yield losses in comparison with the reference scenario (Figure 1). This is due to significant reductions in emissions of the precursors CO, VOCs and NO_X that reduce O_3 concentrations.

The regional picture shows considerable differences. Under the reference scenario, O_3 concentrations over Northeast, Southeast

Asia and Pacific are projected to increase, resulting in additional crop yield losses (Figures 7 and 8). In South, West and Central Asia, both health and agricultural damage are projected to rise (Figure 8). Damage to agriculture is projected to decrease strongly over North America and Europe while changing minimally over Africa and Latin America and the Caribbean. For the whole Asian region maize yields show a decrease of 1–15 per cent, while yields decrease by less than 5 per cent for wheat and rice. These yield losses translate into nearly 40 million tonnes for all crops for the whole Asian region, reflecting the substantial cultivated area exposed to elevated O_3 concentrations in India – in particular the Indo-Gangetic Plain region. Rice production is also affected, particularly in Asia where elevated O_3 concentrations are likely to continue to increase to 2030. Yield loss values for rice are uncertain, however, due to a lack of experimental evidence on concentration-response functions. In contrast, the European and North American regional analyses suggest that all crops will see an improvement in yields under the reference scenario between 2005 and 2030. Even greater improvements would be seen upon implementation of the measures.

The identified measures lead to greatly reduced O_3 concentrations, with substantial benefits to crop yields, especially in Asia (Figure 8). The benefits of the measures are large enough to reverse all the worsening trends seen in agricultural yields and turn them into improvements, relative to 2005, with the exception of crop yields in Northeast and Southeast Asia and Pacific. Even in that case, the benefits of full implementation are quite large, with the measures reducing by 60 per cent the crop losses envisaged in the reference scenario.

It should be stressed that the Assessment's analyses include only the direct effect of changes in atmospheric composition on health and agriculture through changes in exposure to pollutants. As such, they do not include the benefits that avoided climate change would have on human health and agriculture due to factors such as reduced disruption of precipitation patterns, dimming, and reduced frequency of heat waves. Furthermore, even the direct influence on yields are based on estimates for only four staple crops, and impacts on leafy crops, productive grasslands and food quality were not included, so that the calculated values are likely to be an

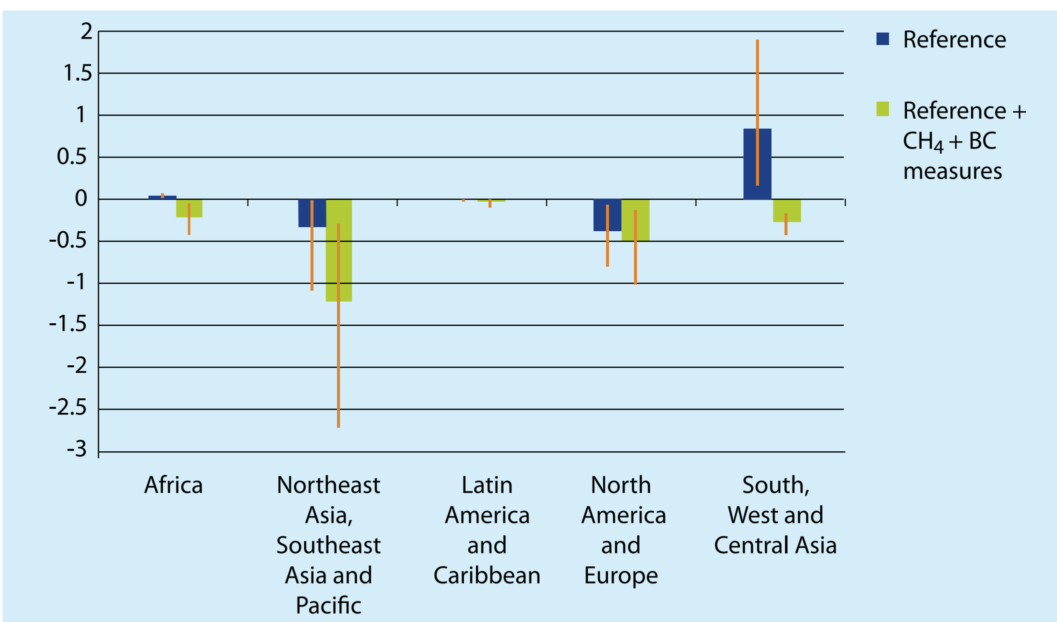


Figure 7. Comparison of premature mortality (millions of premature deaths annually) by region, showing the change in 2030 in comparison with 2005 for the reference scenario emission trends and the reference plus CH_4 + BC measures. The lines on each bar show the range of estimates.

The measures identified in the Assessment include replacement of traditional cookstoves, such as that shown here, with clean burning stoves which would substantially improve air quality and reduce premature deaths due to indoor and outdoor air pollution.

underestimate of the total impact. In addition, extrapolation of results from a number of experimental studies to assess O_3 impacts on ecosystems strongly suggests that reductions in O_3 could lead to substantial increases in the net primary productivity. This could have a substantial impact on carbon sequestration, providing additional climate benefits.

Relative importance and scientific confidence in the measures

Methane measures have a large impact on global and regional warming, which is achieved by reducing the greenhouse gases CH_4 and O_3. The climate mitigation impacts of the CH_4 measures are also the most certain because there is a high degree of confidence in the warming effects of this greenhouse gas. The reduced methane and hence O_3 concentrations also lead to significant benefits for crop yields.

The BC measures identified here reduce concentrations of BC, OC and O_3 (largely through reductions in emissions of CO). The warming effect of BC and O_3 and the compensating cooling effect of OC, introduces large uncertainty in the net effect of some BC measures on global warming (Figure 1). Uncertainty in the impact of BC measures is also larger than that for CH_4 because BC and OC can influence clouds that have multiple effects on climate that are not fully understood. This uncertainly in global impacts is particularly large for the

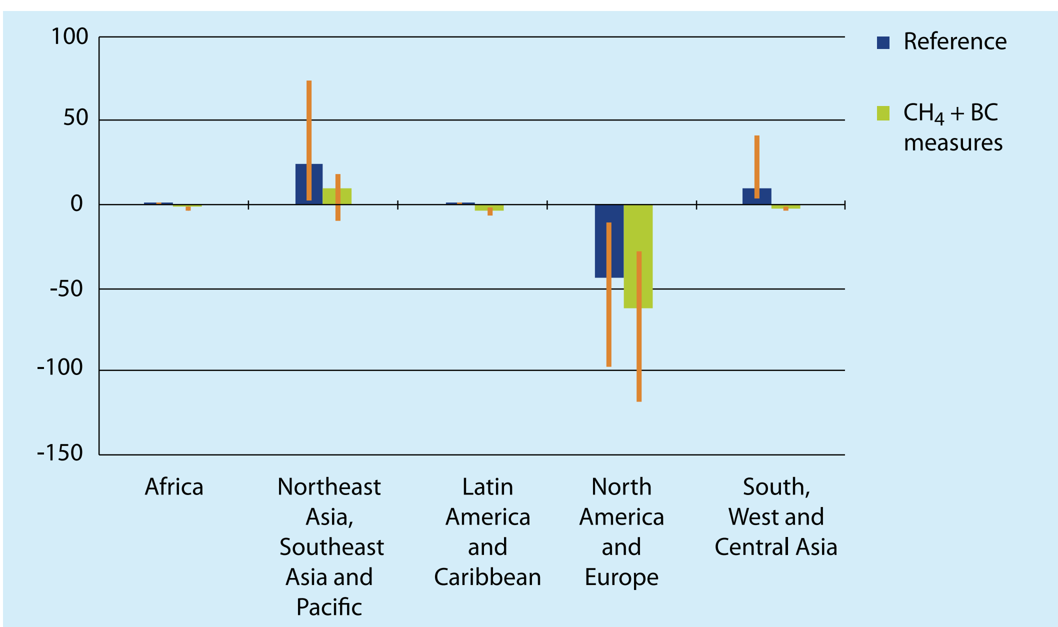
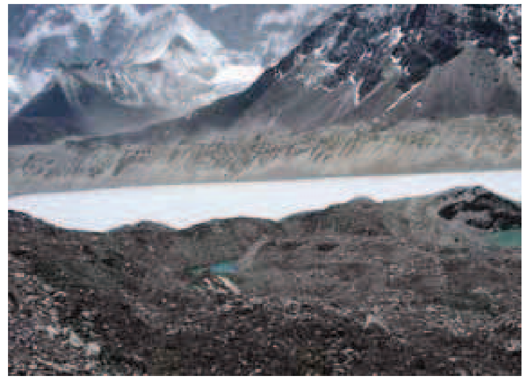


Figure 8. Comparison of crop yield losses (million tonnes annually of four key crops – wheat, rice, maize and soy combined) by region, showing the change in 2030 compared with 2005 for the reference emission trends and the reference with CH_4 + BC measures. The lines on each bar show the range of estimates.

Credit: Veerabhadran Ramanathan

Widespread haze over the Himalayas where BC concentrations can be as high as in mid-sized cities.



Credit: Govind Joshi

Reducing emissions should lower glacial melt and decrease the risk of outbursts from glacial lakes.

measures concerning biomass cookstoves and open burning of biomass. Hence with respect to global warming, there is much higher confidence for measures that mitigate diesel emissions than biomass burning because the proportion of co-emitted cooling OC particles is much lower for diesel.

On the other hand, there is higher confidence that BC measures have large impacts on human health through reducing concentrations of inhalable particles, on crop yields through reduced O_3, and on climate phenomena such as tropical rainfall, monsoons and snow-ice melt. These regional impacts are largely independent of the measures' impact on global warming. In fact, regionally, biomass cookstoves and open biomass burning can have much larger effects than fossil fuels. This is because BC directly increases atmospheric heating by absorbing sunlight, which, according to numerous published studies, affects the monsoon and tropical rainfall, and this is largely separate from the effect of co-emitted OC. The same conclusion applies with respect to the impact of BC measures on snow and ice. BC, because it is dark, significantly increases absorption of sunlight by snow and ice when it is deposited on these bright surfaces. OC that is deposited along with BC has very little effect on sunlight reflected by snow and ice since these surfaces are already very white. Hence knowledge of these regional impacts is, in some cases, more robust than the global impacts, and with respect to reducing regional impacts, all of the BC measures are likely to be significant. Confidence is also high that a large proportion of the health and crop benefits would be realized in Asia.

Mechanisms for rapid implementation

In December 2010 the Parties to the UNFCCC agreed that warming should not exceed 2˚C above pre-industrial levels during this century. This Assessment shows that measures to reduce SLCFs, implemented in combination with CO_2 control measures, would increase the chances of staying below the 2˚C target. The measures would also slow the rate of near-term temperature rise and also lead to significant improvements in health, decreased disruption of regional precipitation patterns and water supply, and in improved food security. The impacts of the measures on temperature change are felt over large geographical areas, while the air quality impacts are more localized near the regions where changes in emissions take place. Therefore, areas that control their emissions will receive the greatest human health and food supply benefits; additionally many of the climate benefits will be felt close to the region taking action.

The benefits would be realized in the near term, thereby providing additional incentives to overcome financial and institutional hurdles to the adoption of these measures. Countries in all regions have successfully implemented the identified measures to some degree for multiple environment and development objectives. These experiences

Credit: Brian Yap

Field burning of agricultural waste is a common way to dispose of crop residue in many regions.

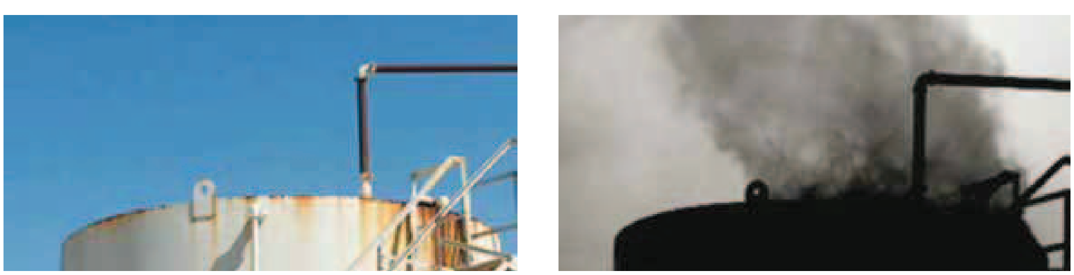
provide a considerable body of knowledge and potential models for others that wish to take action.

In most countries, mechanisms are already in place, albeit at different levels of maturity, to address public concern regarding air pollution problems. Mechanisms to tackle anthropogenic greenhouse gases are less well deployed, and systems to maximize the co-benefits from reducing air pollution and measures to address climate change are virtually non-existent. Coordination across institutions to address climate, air pollution, energy and development policy is particularly important to enhance achievement of all these goals simultaneously.

Many BC control measures require implementation by multiple actors on diffuse emission sources including diesel vehicles, field burning, cookstoves and residential heating. Although air quality and emission standards exist for particulate matter in some regions, they may or may not reduce BC, and implementation remains a challenge. Relevance, benefits and costs of different measures vary from region to region. Many of the measures entail cost savings but require substantial upfront investments. Accounting for air quality, climate and development co-benefits will be key to scaling up implementation.

Methane is one of the six greenhouse gases governed by the Kyoto Protocol, but there are no explicit targets for it. Many CH_4 measures are cost-effective and its recovery is, in many cases, economically profitable. There have been many Clean Development Mechanism (CDM) projects in key CH_4 emitting sectors in the past, though few such projects have been launched in recent years because of lack of financing.

Case studies from both developed and developing countries (Box 3) show that there are technical solutions available to deliver all of the measures (see Chapter 5). Given appropriate policy mechanisms the measures can be implemented, but to achieve the benefits at the scale described much wider implementation is required.



Credit: US EPA

To the naked eye, no emissions from an oil storage tank are visible (left), but with the aid of an infrared camera, escaping CH_4 is evident (right).

Box 3: Case studies of implementation of measures

CH_4 measures

Landfill biogas energy

Landfill CH_4 emissions contribute 10 per cent of the total greenhouse gas emissions in Mexico. Bioenergia de Nuevo Léon S.A. de C.V. (BENLESA) is using landfill biogas as fuel. Currently, the plant has an installed capacity of 12.7 megawatts. Since its opening in September 2003, it has avoided the release of more than 81 000 tonnes of CH_4, equivalent to the reduction in emissions of 1.7 million tonnes of CO_2, generating 409 megawatt hours of electricity. A partnership between government and a private company turned a liability into an asset by converting landfill gas (LFG) into electricity to help drive the public transit system by day and light city streets by night. LFG projects can also be found in Armenia, Brazil, China, India, South Africa, and other countries.

Recovery and flaring from oil and natural gas production

Oil drilling often brings natural gas, mostly CH_4, to the surface along with the oil, which is often vented to the atmosphere to maintain safe pressure in the well. To reduce these emissions, associated gas may be flared and converted to CO_2, or recovered, thus eliminating most of its warming potential and removing its ability to form ozone (O_3). In India, Oil India Limited (OIL), a national oil company, is undertaking a project to recover the gas, which is presently flared, from the Kumchai oil field, and send it to a gas processing plant for eventual transport and use in the natural gas grid. Initiatives in Angola, Indonesia and other countries are flaring and recovering associated gas yielding large reductions in CH_4 emissions and new sources of fuel for local markets.

Livestock manure management

In Brazil, a large CDM project in the state of Mina Gerais seeks to improve waste management systems to reduce the amount of CH_4 and other greenhouse gas emissions associated with animal effluent. The core of the project is to replace open-air lagoons with ambient temperature anaerobic digesters to capture and combust the resulting biogas. Over the course of a 10-year period (2004–2014) the project plans to reduce CH_4 and other greenhouse gas emissions by a total of 50 580 tonnes of CO_2 equivalent. A CDM project in Hyderabad, India, will use the poultry litter CH_4 to generate electricity which will power the plant and supply surplus electricity to the Andhra Pradesh state grid.

Credit: Raphaël V/flickr

Farm scale anaerobic digestion of manure from cattle is one of the key CH_4 measures

Box 3: Case studies of implementation of measures *(continued)*

BC measures

Diesel particle filters

In Santiago, municipal authorities, responding to public concern on air pollution, adopted a new emissions standard for urban buses, requiring installation of diesel particle filters (DPFs). Currently about one-third of the fleet is equipped with filters; it is expected that the entire fleet will be retrofitted by 2018. New York City adopted regulations in 2000 and 2003 requiring use of DPFs in city buses and off-road construction equipment working on city projects. London fitted DPFs to the city's bus fleet over several years beginning in 2003. Low emission zones in London and other cities create incentives for diesel vehicle owners to retrofit with particle filters, allowing them to drive within the city limits. Implementation in developing regions will require greater availability of low sulphur diesel, which is an essential prerequisite for using DPFs.

Improved brick kilns

Small-scale traditional brick kilns are a significant source of air pollution in many developing countries; there are an estimated 20 000 in Mexico alone, emitting large quantities of particulates. An improved kiln design piloted in Ciudad Juárez, near the border with the United States of America, improved efficiency by 50 per cent and decreased particulate pollution by 80 per cent. In the Bac Ninh province of Viet Nam, a project initiated with the aim of reducing ambient air pollution levels and deposition on surrounding rice fields piloted the use of a simple limestone scrubbing emissions control device and demonstrated how a combination of regulation, economic tools, monitoring and technology transfer can significantly improve air quality.


Credit: Alba Corral Avitia


Credit: Robert Marquez

A traditional brick kiln (left) and an improved (right) operating in Mexico.

Potential international regulatory responses

International responses would facilitate rapid and widespread implementation of the measures. Since a large portion of the impacts of SLCFs on climate, health, food security and ecosystems is regional or local in nature, regional approaches incorporating national actions could prove promising for their cost-effective reduction. This approach is still in its very early stage in most regions of the world. For example, the Convention on Long-Range Transboundary Air Pollution (CLRTAP) recently agreed to address BC in the revision of the Gothenburg Protocol in 2011 and to consider the impacts of CH_4 as an O_3 precursor in the longer term.

Other regional agreements (Box 4) are fairly new, and predominantly concentrate on scientific cooperation and capacity building. These arrangements might serve as a platform from which to address the emerging challenges related to air pollution from BC and tropospheric O_3 and provide potential vehicles for finance, technology transfer and capacity development. Sharing good practices

Box 4: Examples of regional atmospheric pollution agreements

The Convention on Long-Range Transboundary Air Pollution (CLRTAP) is a mature policy framework covering Europe, Central Asia and North America. Similar regional agreements have emerged in the last decades in other parts of the world. The Malé Declaration on Control and Prevention of Air Pollution and its Likely Transboundary Effects for South Asia was agreed in 1998 and addresses air quality including tropospheric O_3 and particulate matter. The Association of Southeast Asian Nations (ASEAN) Haze Protocol is a legally binding agreement addresses particulate pollution from forest fires in Southeast Asia. In Africa there are a number of framework agreements between countries in southern Africa (Lusaka Agreement), in East Africa (Nairobi Agreement); and West and Central Africa (Abidjan Agreement). In Latin America and the Caribbean a ministerial level intergovernmental network on air pollution has been formed and there is a draft framework agreement and ongoing collaboration on atmospheric issues under UNEP's leadership.

on an international scale, as is occurring within the Arctic Council, in a coordinated way could provide a helpful way forward.

This Assessment did not assess the cost-effectiveness of different identified measures or policy options under different national circumstances. Doing so would help to inform national air quality and climate policy makers, and support implementation on a wider scale. Further study and analyses of the local application of BC and tropospheric O_3 reduction technologies, costs and regulatory approaches could contribute to advancing adoption of effective action at multiple levels. This work would be best done based on local knowledge. Likewise further evaluation of the regional and global benefits of implementing specific measures by region would help to better target policy efforts. In support of these efforts, additional modelling and monitoring and measurement activities are needed to fill remaining knowledge gaps.

Opportunities for international financing and cooperation

The largest benefits would be delivered in regions where it is unlikely that significant national funds would be allocated to these issues due to other pressing development needs. International financing and technology support would catalyse and accelerate the adoption of the identified measures at sub-national, national and regional levels, especially in developing countries. Financing would be most effective if specifically targeted towards pollution abatement actions that maximize air quality and climate benefits.

Funds and activities to address CH_4 (such as the Global Methane Initiative; and the Global Methane Fund or Prototype Methane Financing Facility) and cookstoves (the Global Alliance for Clean Cookstoves) exist or are under consideration and may serve as models for other sectors. Expanded action will depend on donor recognition of the opportunity represented by SLCF reductions as a highly effective means to address near-term climate change both globally and especially in sensitive regions of the world.

Black carbon and tropospheric O_3 may also be considered as part of other environment, development and energy initiatives such as bilateral assistance, the UN Development Assistance Framework, the World Bank Energy Strategy, the Poverty and Environment Initiative of UNEP and the United Nations Development Programme (UNDP), interagency cooperation initiatives in the UN system such as the Environment Management Group and UN Energy, the UN Foundation, and the consideration by the UN Conference on Sustainable Development (Rio+20) of the institutional framework for sustainable development. These, and others, could take advantage of the opportunities identified in the Assessment to achieve their objectives.

Aerosol measurement instruments

Concluding Remarks

The Assessment establishes the climate co-benefits of air-quality measures that address black carbon and tropospheric ozone and its precursors, especially CH_4 and CO. The measures identified to address these short-lived climate forcers have been successfully tried around the world and have been shown to deliver significant and immediate development and environmental benefits in the local areas and regions where they are implemented.

Costs and benefits of the identified measures are region specific, and implementation often faces financial, regulatory and institutional barriers. However, widespread implementation of the identified measures can be effectively leveraged by recognizing that near-term strategies can slow the rate of global and regional warming, improving our chances of keeping global temperature increase below bounds that significantly lower the probability of major disruptive climate events. Such leverage should spur multilateral initiatives that focus on local priorities and contribute to the global common good.

It is nevertheless stressed that this Assessment does not in any way suggest postponing immediate and aggressive global action on anthropogenic greenhouse gases; in fact it requires such action on CO_2. This Assessment concludes that the chance of success with such longer-term measures can be greatly enhanced by simultaneously addressing short-lived climate forcers.

The benefits identified in this Assessment can be realised with a concerted effort globally to reduce the concentrations of black carbon and tropospheric ozone. A strategy to achieve this, when developed and implemented, will lead to considerable benefits for human well-being.

Glossary

Aerosol	A collection of airborne solid or liquid particles (excluding pure water), with a typical size between 0.01 and 10 micrometers (μm) and residing in the atmosphere for at least several hours. Aerosols may be of either natural or anthropogenic origin. Aerosols may influence climate in two ways: directly through scattering or absorbing radiation, and indirectly through acting as condensation nuclei for cloud formation or modifying the optical properties and lifetime of clouds.
Biofuels	Biofuels are non-fossil fuels. They are energy carriers that store the energy derived from organic materials (biomass), including plant materials and animal waste.
Biomass	In the context of energy, the term biomass is often used to refer to organic materials, such as wood and agricultural wastes, which can be burned to produce energy or converted into a gas and used for fuel.
Black carbon	Operationally defined aerosol species based on measurement of light absorption and chemical reactivity and/or thermal stability. Black carbon is formed through the incomplete combustion of fossil fuels, biofuel, and biomass, and is emitted in both anthropogenic and naturally occurring soot. It consists of pure carbon in several linked forms. Black carbon warms the Earth by absorbing heat in the atmosphere and by reducing albedo, the ability to reflect sunlight, when deposited on snow and ice.
Carbon sequestration	The uptake and storage of carbon. Trees and plants, for example, absorb carbon dioxide, release the oxygen and store the carbon.
Fugitive emissions	Substances (gas, liquid, solid) that escape to the air from a process or a product without going through a smokestack; for example, emissions of methane escaping from coal, oil, and gas extraction not caught by a capture system.
Global warming potential (GWP)	The global warming potential of a gas or particle refers to an estimate of the total contribution to global warming over a particular time that results from the emission of one unit of that gas or particle relative to one unit of the reference gas, carbon dioxide, which is assigned a value of one.
High-emitting vehicles	Poorly tuned or defective vehicles (including malfunctioning emission control system), with emissions of air pollutants (including particulate matter) many times greater than the average.
Hoffman kiln	Hoffmann kilns are the most common kiln used in production of bricks. A Hoffmann kiln consists of a main fire passage surrounded on each side by several small rooms which contain pallets of bricks. Each room is connected to the next room by a passageway carrying hot gases from the fire. This design makes for a very efficient use of heat and fuel.
Incomplete combustion	A reaction or process which entails only partial burning of a fuel. Combustion is almost always incomplete and this may be due to a lack of oxygen or low temperature, preventing the complete chemical reaction.
Oxidation	The chemical reaction of a substance with oxygen or a reaction in which the atoms in an element lose electrons and its valence is correspondingly increased.

Ozone	Ozone, the triatomic form of oxygen (O_3), is a gaseous atmospheric constituent. In the troposphere, it is created both naturally and by photochemical reactions involving gases resulting from human activities (it is a primary component of photochemical smog). In high concentrations, tropospheric ozone can be harmful to a wide range of living organisms. Tropospheric ozone acts as a greenhouse gas. In the stratosphere, ozone is created by the interaction between solar ultraviolet radiation and molecular oxygen. Stratospheric ozone provides a shield from ultraviolet B (UVB) radiation.
Ozone precursor	Chemical compounds, such as carbon monoxide (CO), methane (CH_4), non-methane volatile organic compounds (NMVOC), and nitrogen oxides (NO_X), which in the presence of solar radiation react with other chemical compounds to form ozone in the troposphere.
Particulate matter	Very small pieces of solid or liquid matter such as particles of soot, dust, or other aerosols.
Pre-industrial	Prior to widespread industrialisation and the resultant changes in the environment. Typically taken as the period before 1750.
Radiation	Energy transfer in the form of electromagnetic waves or particles that release energy when absorbed by an object.
Radiative forcing	Radiative forcing is a measure of the change in the energy balance of the Earth-atmosphere system with space. It is defined as the change in the net, downward minus upward, irradiance (expressed in Watts per square metre) at the tropopause due to a change in an external driver of climate change, such as, for example, a change in the concentration of carbon dioxide or the output of the Sun.
Smog	Classically a combination of smoke and fog in which products of combustion, such as hydrocarbons, particulate matter and oxides of sulphur and nitrogen, occur in concentrations that are harmful to human beings and other organisms. More commonly, it occurs as photochemical smog, produced when sunlight acts on nitrogen oxides and hydrocarbons to produce tropospheric ozone.
Stratosphere	Region of the atmosphere between the troposphere and mesosphere, having a lower boundary of approximately 8 km at the poles to 15 km at the equator and an upper boundary of approximately 50 km. Depending upon latitude and season, the temperature in the lower stratosphere can increase, be isothermal, or even decrease with altitude, but the temperature in the upper stratosphere generally increases with height due to absorption of solar radiation by ozone.
Trans-boundary movement	Movement from an area under the national jurisdiction of one State to or through an area under the national jurisdiction of another State or to or through an area not under the national jurisdiction of any State.
Transport (atmospheric)	The movement of chemical species through the atmosphere as a result of large-scale atmospheric motions.
Troposphere	The lowest part of the atmosphere from the surface to about 10 km in altitude in mid-latitudes (ranging from 9 km in high latitudes to 16 km in the tropics on average) where clouds and "weather" phenomena occur. In the troposphere temperatures generally decrease with height.

Acronyms and Abbreviations

ASEAN	Association of Southeast Asian Nations
BC	black carbon
BENLESA	Latin America Bioenergia de Nuevo Léon S.A. de C.V.
CDM	Clean Development Mechanism
CH_4	methane
CLRTAP	Convention on Long-Range Transboundary Air Pollution
CO	carbon monoxide
CO_2	carbon dioxide
DPF	diesel particle filter
ECHAM	Climate-chemistry-aerosol model developed by the Max Planck Institute in Hamburg, Germany
G8	Group of Eight: Canada, France, Germany, Italy, Japan, Russian Federation, United Kingdom, United States
GAINS	Greenhouse Gas and Air Pollution Interactions and Synergies
GISS	Goddard Institute for Space Studies
GWP	global warming potential
IEA	International Energy Agency
IIASA	International Institute for Applied System Analysis
IPCC	Intergovernmental Panel on Climate Change
LFG	landfill gas
NASA	National Aeronautics and Space Administration
NO_x	nitrogen oxides
O_3	ozone
OC	organic carbon
OIL	Oil India Limited
PM	particulate matter ($PM_{2.5}$ has a diameter of 2.5μm or less)
ppm	parts per million
SLCF	short-lived climate forcer
SO_2	sulphur dioxide
UN	United Nations
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
UV	ultraviolet
VOC	volatile organic compound
WMO	World Meteorological Organization

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About the Assessment:

Growing scientific evidence of significant impacts of black carbon and tropospheric ozone on human well-being and the climatic system has catalysed a demand for information and action from governments, civil society and other main stakeholders. The United Nations, in consultation with partner expert institutions and stakeholder representatives, organized an integrated assessment of black carbon and tropospheric ozone, and its precursors, to provide decision makers with a comprehensive assessment of the problem and policy options needed to address it.

An assessment team of more than 50 experts was established, supported by the United Nations Environment Programme, World Meteorological Organization and Stockholm Environment Institute. The Assessment was governed by the Chair and four Vice-Chairs, representing Asia and the Pacific, Europe, Latin America and the Caribbean and North America regions. A High-level Consultative Group, comprising high-profile government advisors, respected scientists, representatives of international organizations and civil society, provided strategic advice on the assessment process and preparation of the *Summary for Decision Makers*.

The draft of the underlying Assessment and its *Summary for Decision Makers* were extensively reviewed and revised based on comments from internal and external review experts. Reputable experts served as review editors to ensure that all substantive expert review comments were afforded appropriate consideration by the authors. The text of the *Summary for Decision Makers* was accepted by the Assessment Chair, Vice-Chairs and the High-level Consultative Group members.

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This document summarizes findings and conclusions of the assessment report: Integrated Assessment of Black Carbon and Tropospheric Ozone. The assessment looks into all aspects of anthropogenic emissions of black carbon and tropospheric ozone precursors, such as methane. It analyses the trends in emissions of these substances and the drivers of these emissions; summarizes the science of atmospheric processes where these substances are involved; discusses related impacts on the climatic system, human health, crops in vulnerable regions and ecosystems; and societal responses to the environmental changes caused by those impacts. The Assessment examines a large number of potential measures to reduce harmful emissions, identifying a small set of specific measures that would likely produce the greatest benefits, and which could be implemented with currently available technology. An outlook up to 2070 is developed illustrating the benefits of those emission mitigation policies and measures for human well-being and climate. The Assessment concludes that rapid mitigation of anthropogenic black carbon and tropospheric ozone emissions would complement carbon dioxide reduction measures and would have immediate benefits for human well-being.

The Summary for Decision Makers was prepared by a writing team with inputs from the members of the High-level Consultative Group and with support from UNEP and WMO. It is intended to serve decision makers at all levels as a guide for assessment, planning and management for the future.

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United States Environmental Protection Agency

Carbon Monoxide
Health

CO can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain) and tissues. At extremely high levels, CO can cause death.

Exposure to CO can reduce the oxygen-carrying capacity of the blood. People with several types of heart disease already have a reduced capacity for pumping oxygenated blood to the heart, which can cause them to experience myocardial ischemia (reduced oxygen to the heart), often accompanied by chest pain (angina), when exercising or under increased stress. For these people, short-term CO exposure further affects their body's already compromised ability to respond to the increased oxygen demands of exercise or exertion.

Last updated on Thursday, August 09, 2012

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2010–0505; FRL–9448–6]

RIN 2060–AP76

Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action announces how the EPA proposes to address the reviews of the new source performance standards for volatile organic compound and sulfur dioxide emissions from natural gas processing plants. We are proposing to add to the source category list any oil and gas operation not covered by the current listing. This action also includes proposed amendments to the existing new source performance standards for volatile organic compounds from natural gas processing plants and proposed standards for operations that are not covered by the existing new source performance standards. In addition, this action proposes how the EPA will address the residual risk and technology review conducted for the oil and natural gas production and natural gas transmission and storage national emission standards for hazardous air pollutants. This action further proposes standards for emission sources within these two source categories that are not currently addressed, as well as amendments to improve aspects of these national emission standards for hazardous air pollutants related to applicability and implementation. Finally, this action addresses provisions in these new source performance standards and national emission standards for hazardous air pollutants related to emissions during periods of startup, shutdown and malfunction.

DATES: Comments must be received on or before October 24, 2011.

Public Hearing. Three public hearings will be held to provide the public an opportunity to provide comments on this proposed rulemaking. One will be held in the Dallas, Texas area, one in Pittsburgh, Pennsylvania, and one in Denver, Colorado, on dates to be announced in a separate document. Each hearing will convene at 10 a.m. local time. For additional information on the public hearings and requesting to speak, see the **SUPPLEMENTARY INFORMATION** section of this preamble.

ADDRESSES: Submit your comments, identified by Docket ID Number EPA–HQ–OAR–2010–0505, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov:* Follow the instructions for submitting comments.
- *Agency Web site: http://www.epa.gov/oar/docket.html.* Follow the instructions for submitting comments on the Air and Radiation Docket Web site.
- *E-mail: a-and-r-docket@epa.gov.* Include Docket ID Number EPA–HQ–OAR–2010–0505 in the subject line of the message.
- *Facsimile:* (202) 566–9744.
- *Mail:* Attention Docket ID Number EPA–HQ–OAR–2010–0505, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attn: Desk Officer for the EPA, 725 17th Street, NW., Washington, DC 20503.
- *Hand Delivery:* United States Environmental Protection Agency, EPA West (Air Docket), Room 3334, 1301 Constitution Ave., NW., Washington, DC 20004, Attention Docket ID Number EPA–HQ–OAR–2010–0505. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID Number EPA–HQ–OAR–2010–0505. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to the EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.* For additional instructions on submitting comments, go to section II.C of the **SUPPLEMENTARY INFORMATION** section of this preamble.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the U.S. Environmental Protection Agency, EPA West (Air Docket), Room 3334, 1301 Constitution Ave., NW., Washington, DC 20004. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT:
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SUPPLEMENTARY INFORMATION:

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. Preamble Acronyms and Abbreviations

Several acronyms and terms used to describe industrial processes, data inventories and risk modeling are included in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined here:

ACGIH American Conference of Governmental Industrial Hygienists
ADAF Age-Dependent Adjustment Factors
AEGL Acute Exposure Guideline Levels
AERMOD The air dispersion model used by the HEM–3 model
API American Petroleum Institute
BACT Best Available Control Technology
BID Background Information Document
BPD Barrels Per Day
BSER Best System of Emission Reduction
BTEX Benzene, Ethylbenzene, Toluene and Xylene
CAA Clean Air Act
CalEPA California Environmental Protection Agency
CBI Confidential Business Information
CEM Continuous Emissions Monitoring
CEMS Continuous Emissions Monitoring System
CFR Code of Federal Regulations
CIIT Chemical Industry Institute of Toxicology
CO Carbon Monoxide
CO_2 Carbon Dioxide
CO_2e Carbon Dioxide Equivalent
DOE Department of Energy
ECHO Enforcement and Compliance History Online
e-GGRT Electronic Greenhouse Gas Reporting Tool
EJ Environmental Justice
EPA Environmental Protection Agency
ERPG Emergency Response Planning Guidelines
ERT Electronic Reporting Tool
GCG Gas Condensate Glycol
GHG Greenhouse Gas
GOR Gas to Oil Ratio
GWP Global Warming Potential
HAP Hazardous Air Pollutants
HEM–3 Human Exposure Model, version 3
HI Hazard Index
HP Horsepower
HQ Hazard Quotient
H_2S Hydrogen Sulfide
ICR Information Collection Request
IPCC Intergovernmental Panel on Climate Change
IRIS Integrated Risk Information System
km Kilometer
kW Kilowatts
LAER Lowest Achievable Emission Rate
lb Pounds
LDAR Leak Detection and Repair
MACT Maximum Achievable Control Technology
MACT Code Code within the NEI used to identify processes included in a source category
Mcf Thousand Cubic Feet
Mg/yr Megagrams per year
MIR Maximum Individual Risk
MIRR Monitoring, Inspection, Recordkeeping and Reporting
$MMtCO_2e$ Million Metric Tons of Carbon Dioxide Equivalents
NAAQS National Ambient Air Quality Standards
NAC/AEGL National Advisory Committee for Acute Exposure Guideline Levels for Hazardous Substances
NAICS North American Industry Classification System
NAS National Academy of Sciences
NATA National Air Toxics Assessment
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NGL Natural Gas Liquids
NIOSH National Institutes for Occupational Safety and Health
NO_X Oxides of Nitrogen
NRC National Research Council
NSPS New Source Performance Standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
PB–HAP Hazardous air pollutants known to be persistent and bio-accumulative in the environment
PFE Potential for Flash Emissions
PM Particulate Matter
$PM_{2.5}$ Particulate Matter (2.5 microns and less)
POM Polycyclic Organic Matter
PPM Parts Per Million
PPMV Parts Per Million by Volume
PSIG Pounds per square inch gauge
PTE Potential to Emit
QA Quality Assurance
RACT Reasonably Available Control Technology
RBLC RACT/BACT/LAER Clearinghouse
REC Reduced Emissions Completions
REL CalEPA Reference Exposure Level
RFA Regulatory Flexibility Act
RfC Reference Concentration
RfD Reference Dose
RIA Regulatory Impact Analysis
RICE Reciprocating Internal Combustion Engines
RTR Residual Risk and Technology Review
SAB Science Advisory Board
SBREFA Small Business Regulatory Enforcement Fairness Act
SCC Source Classification Codes
SCFH Standard Cubic Feet Per Hour
SCFM Standard Cubic Feet Per Minute
SCM Standard Cubic Meters
SCMD Standard Cubic Meters Per Day
SCOT Shell Claus Offgas Treatment
SIP State Implementation Plan
SISNOSE Significant Economic Impact on a Substantial Number of Small Entities
S/L/T State and Local and Tribal Agencies
SO_2 Sulfur Dioxide
SSM Startup, Shutdown and Malfunction
STEL Short-term Exposure Limit
TLV Threshold Limit Value
TOSHI Target Organ-Specific Hazard Index
TPY Tons per Year
TRIM Total Risk Integrated Modeling System
TRIM.FaTE A spatially explicit, compartmental mass balance model that

describes the movement and transformation of pollutants over time, through a user-defined, bounded system that includes both biotic and abiotic compartments
TSD Technical Support Document
UF Uncertainty Factor
UMRA Unfunded Mandates Reform Act
URE Unit Risk Estimate
VCS Voluntary Consensus Standards
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. General Information

A. Does this action apply to me?

The regulated industrial source categories that are the subject of this proposal are listed in Table 1 of this preamble. These standards and any changes considered in this rulemaking would be directly applicable to sources as a Federal program. Thus, Federal, state, local and tribal government entities are not affected by this proposed action.

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS PROPOSED ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211111	Crude Petroleum and Natural Gas Extraction.
	211112	Natural Gas Liquid Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal government	....	Not affected.
State/local/tribal government	....	Not affected.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. To determine whether your facility would be regulated by this action, you should examine the applicability criteria in the regulations. If you have any questions regarding the applicability of this action to a particular entity, contact the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this proposal will also be available on the EPA's Web site. Following signature by the EPA Administrator, a copy of this proposed action will be posted on the EPA's Web site at the following address: *http://www.epa.gov/airquality/oilandgas.*

Additional information is available on the EPA's Residual Risk and Technology Review (RTR) Web site at *http://www.epa.gov/ttn/atw/rrisk/oarpg.html.* This information includes the most recent version of the rule, source category descriptions, detailed emissions and other data that were used as inputs to the risk assessments.

C. What should I consider as I prepare my comments for the EPA?

Submitting CBI. Do not submit information containing CBI to the EPA through *http://www.regulations.gov* or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on a disk or CD ROM that you mail to the EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. If you submit a CD ROM or disk that does not contain CBI, mark the outside of the disk or CD ROM clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711, Attention Docket ID Number EPA–HQ–OAR–2010–0505.

D. When will a public hearing occur?

We will hold three public hearings, one in the Dallas, Texas area, one in Pittsburgh, Pennsylvania, and one in Denver, Colorado. If you are interested in attending or speaking at one of the public hearings, contact Ms. Joan Rogers at (919) 541–4487 by September 6, 2011. Details on the public hearings will be provided in a separate notice and we will specify the time and date of the public hearings on *http://www.epa.gov/airquality/oilandgas.* If no one requests to speak at one of the public hearings by September 6, 2011, then that public hearing will be cancelled without further notice.

III. Background Information

A. What are standards of performance and NSPS?

1. What is the statutory authority for standards of performance and NSPS?

Section 111 of the Clean Air Act (CAA) requires the EPA Administrator to list categories of stationary sources, if such sources cause or contribute significantly to air pollution, which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for such source categories. A performance standard reflects the degree of emission limitation achievable through the application of the ''best system of emission reduction'' (BSER) which the EPA determines has been adequately demonstrated. The EPA may consider certain costs and nonair quality health and environmental impact and energy requirements when establishing performance standards. Whereas CAA section 112 standards are issued for existing and new stationary sources, standards of performance are issued for new and modified stationary sources. These standards are referred to as new source performance standards (NSPS). The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' performance standards unless the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to ''reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' In this notice, we refer to this level of control as the BSER. In determining BSER, we typically conduct a technology review that identifies what emission reduction systems exist and how much they reduce air pollution in practice. Next, for each control system identified, we evaluate its costs, secondary air benefits (or disbenefits) resulting from energy requirements and nonair quality impacts such as solid waste generation. Based on our evaluation, we would determine BSER. The resultant standard is usually a numerical emissions limit, expressed as a performance level (*i.e.,* a rate-based standard or percent control), that reflects the BSER. Although such standards are based on the BSER, the EPA may not prescribe a particular technology that must be used to comply with a performance standard, except in instances where the Administrator determines it is not feasible to prescribe or enforce a standard of performance. Typically, sources remain free to elect whatever control measures that they choose to meet the emission limits. Upon promulgation, an NSPS becomes a national standard to which all new, modified or reconstructed sources must comply.

2. What is the regulatory history regarding performance standards for the oil and natural gas sector?

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). On June 24, 1985 (50 FR 26122), the EPA promulgated an NSPS for the source category that addressed volatile organic compound (VOC) emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates sulfur dioxide (SO_2) emissions from natural gas processing plants (40 CFR part 60, subpart LLL). Other than natural gas processing plants, EPA has not previously set NSPS for a variety of oil and natural gas operations.

B. What are NESHAP?

1. What is the statutory authority for NESHAP?

Section 112 of the CAA establishes a two-stage regulatory process to address emissions of hazardous air pollutants (HAP) from stationary sources. In the first stage, after the EPA has identified categories of sources emitting one or more of the HAP listed in section 112(b) of the CAA, section 112(d) of the CAA calls for us to promulgate national emission standards for hazardous air pollutants (NESHAP) for those sources. ''Major sources'' are those that emit or have the potential to emit (PTE) 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of any combination of HAP. For major sources, these technology-based standards must reflect the maximum degree of emission reductions of HAP achievable (after considering cost, energy requirements and nonair quality health and environmental impacts) and are commonly referred to as maximum achievable control technology (MACT) standards.

MACT standards are to reflect application of measures, processes, methods, systems or techniques, including, but not limited to, measures which, (1) reduce the volume of or eliminate pollutants through process changes, substitution of materials or other modifications, (2) enclose systems or processes to eliminate emissions, (3) capture or treat pollutants when released from a process, stack, storage or fugitive emissions point, (4) are design, equipment, work practice or operational standards (including requirements for operator training or certification) or (5) are a combination of the above. CAA section 112(d)(2)(A)–(E). The MACT standard may take the form of a design, equipment, work practice or operational standard where the EPA first determines either that, (1) a pollutant cannot be emitted through a conveyance designed and constructed to emit or capture the pollutant or that any requirement for or use of such a conveyance would be inconsistent with law or (2) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations. CAA sections 112(h)(1)–(2).

The MACT ''floor'' is the minimum control level allowed for MACT standards promulgated under CAA section 112(d)(3), and may not be based on cost considerations. For new sources, the MACT floor cannot be less stringent than the emission control that is achieved in practice by the best-controlled similar source. The MACT floors for existing sources can be less stringent than floors for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources). In developing MACT standards, we must also consider control options that are more stringent than the floor. We may establish standards more stringent than the floor based on the consideration of the cost of achieving the emissions reductions, any nonair quality health and environmental impacts and energy requirements.

The EPA is then required to review these technology-based standards and to revise them ''as necessary (taking into account developments in practices, processes, and control technologies)'' no less frequently than every 8 years, under CAA section 112(d)(6). In conducting this review, the EPA is not obliged to completely recalculate the prior MACT determination. *NRDC* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008).

The second stage in standard-setting focuses on reducing any remaining ''residual'' risk according to CAA section 112(f). This provision requires, first, that the EPA prepare a *Report to Congress* discussing (among other things) methods of calculating risk posed (or potentially posed) by sources after implementation of the MACT standards, the public health significance of those risks, and the EPA's recommendations as to legislation regarding such remaining risk. The EPA prepared and submitted this report (*Residual Risk Report to Congress,* EPA–453/R–99–001) in March 1999. Congress did not act in response to the report, thereby triggering the EPA's obligation under CAA section 112(f)(2) to analyze and address residual risk.

CAA section 112(f)(2) requires us to determine for source categories subject to MACT standards, whether the emissions standards provide an ample margin of safety to protect public health. If the MACT standards for HAP ''classified as a known, probable, or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to emissions from a source in the category or subcategory to less than 1-in-1 million,'' the EPA must promulgate residual risk standards for the source category (or subcategory), as necessary, to provide an ample margin of safety to protect public health. In doing so, the EPA may adopt standards equal to existing MACT standards if the EPA determines that the existing standards are sufficiently protective. *NRDC* v. *EPA,* 529 F.3d 1077, 1083 (D.C. Cir. 2008). (''If EPA determines that the existing technology-based standards provide an ''ample margin of safety,'' then the Agency is free to readopt those standards during the residual risk rulemaking.'') The EPA must also adopt more stringent standards, if necessary, to prevent an adverse environmental effect,[1] but must consider cost, energy, safety and other relevant factors in doing so.

Section 112(f)(2) of the CAA expressly preserves our use of a two-step process for developing standards to address any residual risk and our interpretation of ''ample margin of safety'' developed in the *National Emission Standards for Hazardous Air Pollutants: Benzene Emissions from Maleic Anhydride Plants, Ethylbenzene/Styrene Plants, Benzene Storage Vessels, Benzene Equipment Leaks, and Coke By-Product Recovery Plants (Benzene NESHAP)* (54 FR 38044, September 14, 1989). The first step in this process is the determination of acceptable risk. The second step provides for an ample margin of safety to protect public health, which is the level at which the standards are set (unless a more stringent standard is required to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect).

The terms ''individual most exposed,'' ''acceptable level,'' and ''ample margin of safety'' are not specifically defined in the CAA. However, CAA section 112(f)(2)(B) preserves the interpretation set out in the Benzene NESHAP, and the United States Court of Appeals for the District of Columbia Circuit in *NRDC* v. *EPA,* 529 F.3d 1077, concluded that the EPA's interpretation of subsection 112(f)(2) is a reasonable one. See *NRDC* v. *EPA,* 529 F.3d at 1083 (D.C. Cir., ''[S]ubsection 112(f)(2)(B) expressly incorporates EPA's interpretation of the Clean Air Act from the Benzene standard, complete with a citation to the **Federal Register**''). (D.C. Cir. 2008). See also, *A Legislative History of the Clean Air Act Amendments of 1990,* volume 1, p. 877 (Senate debate on Conference Report). We notified Congress in the *Residual Risk Report to Congress* that we intended to use the Benzene NESHAP approach in making CAA section 112(f) residual risk determinations (EPA–453/R–99–001, p. ES–11).

In the Benzene NESHAP, we stated as an overall objective:

> * * * in protecting public health with an ample margin of safety, we strive to provide maximum feasible protection against risks to health from hazardous air pollutants by, (1) protecting the greatest number of persons possible to an individual lifetime risk level no higher than approximately 1-in-1 million; and (2) limiting to no higher than approximately 1-in-10 thousand [*i.e.,* 100-in-1 million] the estimated risk that a person living near a facility would have if he or she were exposed to the maximum pollutant concentrations for 70 years.

The Agency also stated that, ''The EPA also considers incidence (the number of persons estimated to suffer cancer or other serious health effects as a result of exposure to a pollutant) to be an important measure of the health risk to the exposed population. Incidence measures the extent of health risk to the exposed population as a whole, by providing an estimate of the occurrence of cancer or other serious health effects in the exposed population.'' The Agency went on to conclude that ''estimated incidence would be weighed along with other health risk information in judging acceptability.'' As explained more fully in our *Residual Risk Report to Congress,* the EPA does not define ''rigid line[s] of acceptability,'' but considers rather broad objectives to be weighed with a series of other health measures and factors (EPA–453/R–99–001, p. ES–11). The determination of what represents an ''acceptable'' risk is based on a judgment of ''what risks are acceptable in the world in which we live'' (*Residual Risk Report to Congress,* p. 178, quoting the Vinyl Chloride decision at 824 F.2d 1165) recognizing that our world is not risk-free.

In the Benzene NESHAP, we stated that ''EPA will generally presume that if the risk to [the maximum exposed] individual is no higher than approximately 1-in-10 thousand, that risk level is considered acceptable.'' 54 FR 38045. We discussed the maximum individual lifetime cancer risk (or maximum individual risk (MIR)) as being ''the estimated risk that a person living near a plant would have if he or she were exposed to the maximum pollutant concentrations for 70 years.'' *Id.* We explained that this measure of risk ''is an estimate of the upper bound of risk based on conservative assumptions, such as continuous exposure for 24 hours per day for 70 years.'' *Id.* We acknowledge that maximum individual lifetime cancer risk ''does not necessarily reflect the true risk, but displays a conservative risk level which is an upper-bound that is unlikely to be exceeded.'' *Id.*

Understanding that there are both benefits and limitations to using maximum individual lifetime cancer risk as a metric for determining acceptability, we acknowledged in the 1989 Benzene NESHAP that ''consideration of maximum individual risk * * * must take into account the strengths and weaknesses of this measure of risk.'' *Id.* Consequently, the presumptive risk level of 100-in-1 million (1-in-10 thousand) provides a benchmark for judging the acceptability of maximum individual lifetime cancer risk, but does not constitute a rigid line for making that determination.

The Agency also explained in the 1989 Benzene NESHAP the following: ''In establishing a presumption for MIR, rather than a rigid line for acceptability, the Agency intends to weigh it with a series of other health measures and factors. These include the overall incidence of cancer or other serious health effects within the exposed population, the numbers of persons exposed within each individual lifetime risk range and associated incidence within, typically, a 50-kilometer (km) exposure radius around facilities, the science policy assumptions and estimation uncertainties associated with the risk measures, weight of the scientific evidence for human health effects, other quantified or unquantified health effects, effects due to co-location of facilities and co-emission of pollutants.'' *Id.*

In some cases, these health measures and factors taken together may provide a more realistic description of the magnitude of risk in the exposed population than that provided by maximum individual lifetime cancer risk alone. As explained in the Benzene NESHAP, ''[e]ven though the risks judged ''acceptable'' by the EPA in the first step of the Vinyl Chloride inquiry are already low, the second step of the inquiry, determining an ''ample margin of safety,'' again includes consideration of all of the health factors, and whether to reduce the risks even further.'' In the ample margin of safety decision process, the Agency again considers all of the health risks and other health information considered in the first step. Beyond that information, additional factors relating to the appropriate level

[1] ''Adverse environmental effect'' is defined in CAA section 112(a)(7) as any significant and widespread adverse effect, which may be reasonably anticipated to wildlife, aquatic life or natural resources, including adverse impacts on populations of endangered or threatened species or significant degradation of environmental qualities over broad areas.

of control will also be considered, including costs and economic impacts of controls, technological feasibility, uncertainties and any other relevant factors. Considering all of these factors, the Agency will establish the standard at a level that provides an ample margin of safety to protect the public health, as required by CAA section 112(f). 54 FR 38046.

2. How do we consider the risk results in making decisions?

As discussed in the previous section of this preamble, we apply a two-step process for developing standards to address residual risk. In the first step, the EPA determines if risks are acceptable. This determination ''considers all health information, including risk estimation uncertainty, and includes a presumptive limit on maximum individual lifetime [cancer] risk (MIR)[2] of approximately 1-in-10 thousand [*i.e.,* 100-in-1 million].'' 54 FR 38045. In the second step of the process, the EPA sets the standard at a level that provides an ample margin of safety ''in consideration of all health information, including the number of persons at risk levels higher than approximately 1-in-1 million, as well as other relevant factors, including costs and economic impacts, technological feasibility, and other factors relevant to each particular decision.'' *Id.*

In past residual risk determinations, the EPA presented a number of human health risk metrics associated with emissions from the category under review, including: The MIR; the numbers of persons in various risk ranges; cancer incidence; the maximum noncancer hazard index (HI); and the maximum acute noncancer hazard. In estimating risks, the EPA considered source categories under review that are located near each other and that affect the same population. The EPA provided estimates of the expected difference in actual emissions from the source category under review and emissions allowed pursuant to the source category MACT standard. The EPA also discussed and considered risk estimation uncertainties. The EPA is providing this same type of information in support of these actions.

The Agency acknowledges that the Benzene NESHAP provides flexibility regarding what factors the EPA might consider in making our determinations and how they might be weighed for each source category. In responding to comment on our policy under the Benzene NESHAP, the EPA explained that: ''The policy chosen by the Administrator permits consideration of multiple measures of health risk. Not only can the MIR figure be considered, but also incidence, the presence of noncancer health effects, and the uncertainties of the risk estimates. In this way, the effect on the most exposed individuals can be reviewed as well as the impact on the general public. These factors can then be weighed in each individual case. This approach complies with the Vinyl Chloride mandate that the Administrator ascertain an acceptable level of risk to the public by employing [her] expertise to assess available data. It also complies with the Congressional intent behind the CAA, which did not exclude the use of any particular measure of public health risk from the EPA's consideration with respect to CAA section 112 regulations, and, thereby, implicitly permits consideration of any and all measures of health risk which the Administrator, in [her] judgment, believes are appropriate to determining what will 'protect the public health.' ''

For example, the level of the MIR is only one factor to be weighed in determining acceptability of risks. The Benzene NESHAP explains ''an MIR of approximately 1-in-10 thousand should ordinarily be the upper end of the range of acceptability. As risks increase above this benchmark, they become presumptively less acceptable under CAA section 112, and would be weighed with the other health risk measures and information in making an overall judgment on acceptability. Or, the Agency may find, in a particular case, that a risk that includes MIR less than the presumptively acceptable level is unacceptable in the light of other health risk factors.'' Similarly, with regard to the ample margin of safety analysis, the Benzene NESHAP states that: ''EPA believes the relative weight of the many factors that can be considered in selecting an ample margin of safety can only be determined for each specific source category. This occurs mainly because technological and economic factors (along with the health-related factors) vary from source category to source category.''

3. What is the regulatory history regarding NESHAP for the oil and natural gas sector?

On July 16, 1992 (57 FR 31576), the EPA published a list of major and area sources for which NESHAP are to be published (*i.e.,* the source category list). Oil and natural gas production facilities were listed as a category of major sources. On February 12, 1998 (63 FR 7155), the EPA amended the source category list to add Natural Gas Transmission and Storage as a major source category.

On June 17, 1999 (64 FR 32610), the EPA promulgated MACT standards for the Oil and Natural Gas Production and Natural Gas Transmission and Storage major source categories. The Oil and Natural Gas Production NESHAP (40 CFR part 63, subpart HH) contains standards for HAP emissions from glycol dehydration process vents, storage vessels and natural gas processing plant equipment leaks. The Natural Gas Transmission and Storage NESHAP (40 CFR part 63, subpart HHH) contains standards for glycol dehydration process vents.

In addition to these NESHAP for major sources, the EPA also promulgated NESHAP for the Oil and Natural Gas Production area source category on January 3, 2007 (72 FR 26). These area source standards, which are based on generally available control technology, are also contained in 40 CFR part 63, subpart HH. This proposed action does not impact these area source standards.

C. What litigation is related to this proposed action?

On January 14, 2009, pursuant to section 304(a)(2) of the CAA, WildEarth Guardians and the San Juan Citizens Alliance filed a Complaint alleging that the EPA failed to meet its obligations under CAA sections 111(b)(1)(B), 112(d)(6) and 112(f)(2) to take actions relative to the review/revision of the NSPS and the NESHAP with respect to the Oil and Natural Gas Production source category. On February 4, 2010, the Court entered a consent decree requiring the EPA to sign by July 28, 2011,[3] proposed standards and/or determinations not to issue standards pursuant to CAA sections 111(b)(1)(B), 112(d)(6) and 112(f)(2) and to take final action by February 28, 2012.

D. What is a sector-based approach?

Sector-based approaches are based on integrated assessments that consider multiple pollutants in a comprehensive and coordinated manner to manage emissions and CAA requirements. One of the many ways we can address sector-based approaches is by reviewing multiple regulatory programs together whenever possible, consistent with all

[2] Although defined as ''maximum individual risk,'' MIR refers only to cancer risk. MIR, one metric for assessing cancer risk, is the estimated risk were an individual exposed to the maximum level of a pollutant for a lifetime.

[3] On April 27, 2011, pursuant to paragraph 10(a) of the Consent Decree, the parties filed with the Court a written stipulation that changes the proposal date from January 31, 2011, to July 28, 2011, and the final action date from November 30, 2011, to February 28, 2012.

applicable legal requirements. This approach essentially expands the technical analyses on costs and benefits of particular technologies, to consider the interactions of rules that regulate sources. The benefit of multi-pollutant and sector-based analyses and approaches includes the ability to identify optimum strategies, considering feasibility, cost impacts and benefits across the different pollutant types while streamlining administrative and compliance complexities and reducing conflicting and redundant requirements, resulting in added certainty and easier implementation of control strategies for the sector under consideration. In order to benefit from a sector-based approach for the oil and gas industry, the EPA analyzed how the NSPS and NESHAP under consideration relate to each other and other regulatory requirements currently under review for oil and gas facilities. In this analysis, we looked at how the different control requirements that result from these requirements interact, including the different regulatory deadlines and control equipment requirements that result, the different reporting and recordkeeping requirements and opportunities for states to account for reductions resulting from this rulemaking in their State Implementation Plans (SIP). The requirements analyzed affect criteria pollutant, HAP and methane emissions from oil and natural gas processes and cover the NSPS and NESHAP reviews. As a result of the sector-based approach, this rulemaking will reduce conflicting and redundant requirements. Also, the sector-based approach facilitated the streamlining of monitoring, recordkeeping and reporting requirements, thus, reducing administrative and compliance complexities associated with complying with multiple regulations. In addition, the sector-based approach promotes a comprehensive control strategy that maximizes the co-control of multiple regulated pollutants while obtaining emission reductions as co-benefits.

IV. Oil and Natural Gas Sector

The oil and natural gas sector includes operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas. Specifically for oil, the sector includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the sector includes all operations from the well to the customer. The oil and natural gas operations can generally be separated into four segments: (1) Oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and (4) natural gas distribution. Each of these segments is briefly discussed below.

Oil and natural gas production includes both onshore and offshore operations. Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and ''Christmas tree'' piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include the well drilling, completion and workover processes and includes all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the ''pads'' where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production sector also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants. None of the operations upstream of the natural gas processing plant are covered by the existing NSPS. Offshore oil and natural gas production occurs on platform structures that house equipment to extract oil and gas from the ocean or lake floor and that process and/or transfer the oil and gas to storage, transport vessels or onshore. Offshore production can also include secondary platform structures connected to the platform structure, storage tanks associated with the platform structure and floating production and offloading equipment.

There are three basic types of wells: Oil wells, gas wells and associated gas wells. Oil wells can have ''associated'' natural gas that is separated and processed or the crude oil can be the only product processed. Once the crude oil is separated from the water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar or pipeline. We consider the oil refinery sector separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced ''pipeline quality'' dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover NGL or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of NGL, sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility. Natural gas processing plants are the only operations covered by the existing NSPS.

The pipeline quality natural gas leaves the processing segment and enters the transmission segment. Pipelines in the natural gas transmission segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission segment includes underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration and flow measurement.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. The delivery point where the natural gas leaves the transmission segment and enters the distribution segment is often called the ''citygate.'' Typically, utilities take ownership of the gas at the citygate. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas sector. Primarily, these emissions are organic compounds such as methane, ethane, VOC and organic HAP. The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide (H_2S) and sulfur dioxide (SO_2) are emitted from production and processing operations that handle and treat ''sour gas.'' Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2.

In addition, there are significant emissions associated with the reciprocating internal combustion engines and combustion turbines that power compressors throughout the oil and natural gas sector. However, emissions from internal combustion engines and combustion turbines are covered by regulations specific to engines and turbines and, thus, are not addressed in this action.

V. Summary of Proposed Decisions and Actions

Pursuant to CAA sections 111(b), 112(d)(2), 112(d)(6) and 112(f), we are proposing to revise the NSPS and NESHAP relative to oil and gas to include the standards and requirements summarized in this section. More details of the rationale for these proposed standards and requirements are provided in sections VI and VII of this preamble. In addition, as part of these rationale discussions, we solicit public comment and data relevant to several issues. The comments we receive during the public comment period will help inform the rule development process as we work toward promulgating a final action.

A. What are the proposed revisions to the NSPS?

We reviewed the two NSPS that apply to the oil and natural gas industry. Based on our review, we believe that the requirements at 40 CFR part 60, subpart KKK, should be updated to reflect requirements in 40 CFR part 60, subpart VVa for controlling VOC equipment leaks at processing plants. We also believe that the requirements at 40 CFR part 60, subpart LLL, for controlling SO_2 emissions from natural gas processing plants should be strengthened for facilities with the highest sulfur feed rates and the highest H_2S concentrations. For a more detailed discussion, please see section VI.B.1 of this preamble.

In addition, there are significant VOC emissions from oil and natural gas operations that are not covered by the two existing NSPS, including other emissions at processing plants and emissions from upstream production, as well as transmission and storage facilities. In the 1984 notice that listed source categories (including Oil and Natural Gas) for promulgation of NSPS, we noted that there were discrepancies between the source category names on the list and those in the background document, and we clarified our intent to address all sources under an industry heading at the same time. See 44 FR 49222, 49224–49225.[4] We, therefore, believe that the currently listed Oil and Natural Gas source category covers all operations in this industry (*i.e.,* production, processing, transmission, storage and distribution). To the extent there are oil and gas operations not covered by the currently listed Oil and Natural Gas source category, pursuant to CAA section 111(b), we hereby modify the category list to include all operations in the oil and natural gas sector. Section 111(b) of the CAA gives the EPA broad authority and discretion to list and establish NSPS for a category that, in the Administrator's judgment, causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Pursuant to CAA section 111(b), we are modifying the source category list to include any oil and gas operation not covered by the current listing and evaluating emissions from all oil and gas operations at the same time.

We are also proposing standards for several new oil and natural gas affected facilities. The proposed standards would apply to affected facilities that commence construction, reconstruction or modification after August 23, 2011. These standards, which include requirements for VOC, would be contained in a new subpart, 40 CFR part 60, subpart OOOO. Subpart OOOO would incorporate 40 CFR part 60, subpart KKK and 40 CFR part 60, subpart LLL, thereby having in this one subpart, all standards that are applicable to the new and modified affected facilities described above. We also propose to amend the title of subparts KKK and LLL, accordingly, to apply only to affected facilities already subject to those subparts. Those operations would not become subject to subpart OOOO unless they triggered applicability based on new or modified affected facilities under subpart OOOO.

We are proposing operational standards for completions of hydraulically fractured gas wells. Based on our review, we identified two subcategories of fractured gas wells for which well completions are conducted. For non-exploratory and non-delineation wells, the proposed operational standards would require reduced emission completion (REC), commonly referred to as ''green completion,'' in combination with pit-flaring of gas not suitable for entering the gathering line. For exploratory and delineation wells (these wells generally are not in close proximity to a gathering line), we proposed an operational standard that would require pit flaring. Well completions subject to the standards would be limited to gas well completions following hydraulic fracturing operations. These completions include those conducted at newly drilled and fractured wells, as well as completions conducted following refracturing operations at various times over the life of the well. We have determined that a completion associated with refracturing performed at an existing well (*i.e.,* a well existing prior to August 23, 2011) is considered a modification under CAA section 111(a), because physical change occurs to the existing well resulting in emissions increase during the refracturing and completion operation. A detailed discussion of this determination is presented in the Technical Support Document (TSD) in the docket. Therefore, the proposed standards would apply to completions at new gas wells that are fractured or

[4] The Notice further states that ''The Administrator may also concurrently develop standards for sources which are not on the priority list.'' 44 FR at 49225.

refractured along with completions associated with fracturing or refracturing of existing gas wells. The modification determination and resultant applicability of NSPS to the completion operation following fracturing or refracturing of existing gas wells (*i.e.,* wells existing before August 23, 2011 would be limited strictly to the wellhead, well bore, casing and tubing, and any conveyance through which gas is vented to the atmosphere and not be extended beyond the wellhead to other ancillary components that may be at the well site such as existing storage vessels, process vessels, separators, dehydrators or any other components or apparatus.

We are also proposing VOC standards to reduce emissions from gas-driven pneumatic devices. We are proposing that each pneumatic device is an affected facility. Accordingly, the proposed standards would apply to each newly installed pneumatic device (including replacement of an existing device). At gas processing plants, we are proposing a zero emission limit for each individual pneumatic controller. The proposed emission standards would reflect the emission level achievable from the use of non-gas-driven pneumatic controllers. At other locations, we are proposing a bleed limit of 6 standard cubic feet of gas per hour for an individual pneumatic controller, which would reflect the emission level achievable from the use of low bleed gas-driven pneumatic controllers. In both cases, the standards provide exemptions for certain applications based on functional considerations.

In addition, the proposed rule would require measures to reduce VOC emissions from centrifugal and reciprocating compressors. As explained in more detail below in section VI.B.4, we are proposing equipment standards for centrifugal compressors. The proposed standards would require the use of dry seal systems. However, we are aware that some owners and operators may need to use centrifugal compressors with wet seals, and we are soliciting comment on the suitability of a compliance option allowing the use of wet seals combined with routing of emissions from the seal liquid through a closed vent system to a control device as an acceptable alternative to installing dry seals.

Our review of reciprocating compressors found that piston rod packing wear produces fugitive emissions that cannot be captured and conveyed to a control device. As a result, we are proposing operational standards for reciprocating compressors, such that the proposed rule would require replacement of the rod packing based on hours of usage. The owner or operator of a reciprocating compressor affected facility would be required to monitor the duration (in hours) that the compressor is operated. When the hours of operation reaches 26,000 hours, the owner or operator would be required to change the rod packing immediately. However, to avoid unscheduled shutdowns when 26,000 hours is reached, owners and operators could track hours of operation such that packing replacement could be coordinated with planned maintenance shutdowns before hours of operation reached 26,000. Some operators may prefer to replace the rod packing on a fixed schedule to ensure that the hours of operation would not reach 26,000 hours. We solicit comment on the appropriateness of a fixed replacement frequency and other considerations that would be associated with regular replacement.

We are also proposing VOC standards for new or modified storage vessels. The proposed rule, which would apply to individual vessels, would require that vessels meeting certain specifications achieve at least 95-percent reduction in VOC emissions. Requirements would apply to vessels with a throughput of 1 barrel of condensate per day or 20 barrels of crude oil per day. These thresholds are equivalent to VOC emissions of about 6 tpy.

For gas processing plants, we are updating the requirements for leak detection and repair (LDAR) to reflect procedures and leak thresholds established by 40 CFR 60, subpart VVa. The existing NSPS requires 40 CFR part 60, subpart VV procedures and thresholds.

For 40 CFR part 60, subpart LLL, which regulates SO_2 emissions from natural gas processing plants, we determined that affected facilities with sulfur feed rate of at least 5 long tons per day or H_2S concentration in the acid gas stream of at least 50 percent can achieve up to 99.9-percent SO_2 control, which is greater than the existing standard. Therefore, we are proposing revision to the performance standards in subpart LLL as a result of this review. For a more detailed discussion of this proposed determination, please see section VI.B.1 of this preamble.

We are proposing to address compliance requirements for periods of startup, shutdown and malfunction (SSM) for 40 CFR part 60, subpart OOOO. The SSM changes are discussed in detail in section VI.B.5 below. In addition, we are proposing to incorporate the requirements in 40 CFR part 60, subpart KKK and 40 CFR part 60, subpart LLL into the new subpart OOOO so that all requirements applicable to the new and modified facilities would be in one subpart. This would simplify and streamline compliance efforts on the part of the oil and natural gas industry and could minimize duplication of notification, recordkeeping and reporting.

B. What are the proposed decisions and actions related to the NESHAP?

This section summarizes the results of our RTR for the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories and our proposed decisions concerning these two 1999 NESHAP.

1. Addressing Unregulated Emissions Sources

Pursuant to CAA sections 112(d)(2) and (3), we are proposing MACT standards for subcategories of glycol dehydrators for which standards were not previously developed (hereinafter referred to as the ''small dehydrators''). In the Oil and Natural Gas Production source category, the subcategory consists of glycol dehydrators with an actual annual average natural gas flowrate less than 85,000 standard cubic meters per day (scmd) or actual average benzene emissions less than 0.9 megagrams per year (Mg/yr). In the Natural Gas Transmission and Storage source category, the subcategory consists of glycol dehydrators with an actual annual average natural gas flowrate less than 283,000 scmd or actual average benzene emissions less than 0.9 Mg/yr.

The proposed MACT standards for the subcategory of small dehydrators at oil and gas production facilities would require that existing affected sources meet a unit-specific BTEX limit of 1.10×10^{-4} grams BTEX/standard cubic meters (scm)-parts per million by volume (ppmv) and that new affected sources meet a BTEX limit of 4.66×10^{-6} grams BTEX/scm-ppmv. At natural gas transmission and storage affected sources, the proposed MACT standard for the subcategory of small dehydrators would require that existing affected sources meet a unit-specific BTEX emission limit of 6.42×10^{-5} grams BTEX/scm-ppmv and that new affected sources meet a BTEX limit of 1.10×10^{-5} grams BTEX/scm-ppmv.

We are also proposing MACT standards for storage vessels that are currently not regulated under the Oil and Natural Gas Production NESHAP. The current MACT standards apply only to storage vessels with the potential for flash emissions (PFE). As explained in section VII, the original MACT analysis accounted for all storage vessels. We are, therefore, proposing to apply the current MACT standards of 95-percent emission reduction to every storage vessel at major source oil and natural gas production facilities. In conjunction with this change, we are proposing to amend the definition of associated equipment to exclude all storage vessels, and not just those with the PFE, from being considered ''associated equipment.'' This means that emissions from all storage vessels, and not just those from storage vessels with the PFE, are to be included in the major source determination.

2. What are the proposed decisions and actions related to the risk review?

For both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories, we find that the current levels of emissions allowed by the MACT reflect acceptable levels of risk; however, the level of emissions allowed by the alternative compliance option for glycol dehydrator MACT (*i.e.*, the option of reducing benzene emissions to less than 0.9 Mg/yr in lieu of the MACT standard of 95-percent control) reflects an unacceptable level of risk. We are, therefore, proposing to eliminate the 0.9 Mg/yr alternative compliance option.

In addition, we are proposing that the MACT for these two oil and gas source categories, as revised per above, provide an ample margin of safety to protect public health and prevent adverse environmental effects.

3. What are the proposed decisions and actions related to the technology reviews of the existing NESHAP?

For both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories, we are proposing no revisions to the existing NESHAP pursuant to section 112(d)(6) of the CAA.

4. What other actions are we proposing?

We are proposing an alternative performance test for non-flare, combustion control devices. This test is to be conducted by the combustion control device manufacturer to demonstrate the destruction efficiency achieved by a specific model of combustion control device. This would allow a source to purchase a performance tested device for installation at their site without being required to conduct a site-specific performance test. A definition for ''flare'' is being proposed in the NESHAP to clarify which combustion control devices fall under the manufacturers' performance testing alternative, and to clarify which devices must be performance tested.

We are also proposing to: Revise the parametric monitoring calibration provisions; require periodic performance testing where applicable; remove the allowance of a design analysis for all control devices other than condensers; remove the requirement for a minimum residence time for an enclosed combustion device; and add recordkeeping and reporting requirements to document carbon replacement intervals. These changes are being proposed to bring the NESHAP up-to-date based on what we have learned regarding control devices and compliance since the original promulgation date.

In addition, we are proposing the elimination of the SSM exemption in the Oil and Natural Gas Production and the Natural Gas Transmission and Storage NESHAP. As discussed in more detail below in section VII, consistent with *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2010), the EPA is proposing that the established standards in these two NESHAP apply at all times. We are proposing to revise Table 2 to both 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH to indicate that certain 40 CFR part 63 general provisions relative to SSM do not apply, including: 40 CFR 63.6 (e)(1)(i) [5] and (ii), 40 CFR 63.6(e)(3) (SSM plan requirement), 40 CFR 63.6(f)(1); 40 CFR 63.7(e)(1), 40 CFR 63.8(c)(1)(i) and (iii), and the last sentence of 40 CFR 63.8(d)(3); 40 CFR 63.10(b)(2)(i),(ii), (iv) and (v); 40 CFR 63.10(c)(10), (11) and (15); and 40 CFR 63.10(d)(5). We are also proposing to: (1) Revise 40 CFR 63.771(d)(4)(i) and 40 CFR 63.1281(d)(4)(i) regarding operation of the control device to be consistent with the SSM compliance requirements; and (2) revise the SSM-associated reporting and recordkeeping requirements in 40 CFR 63.774, 40 CFR 63.775, 40 CFR 63.1284 and 40 CFR 63.1285 to require reporting and recordkeeping for periods of malfunction. In addition, as explained below, we are proposing to add an affirmative defense to civil penalties for exceedances of emission limits caused by malfunctions, as well as criteria for establishing the affirmative defense.

The EPA has attempted to ensure that we have neither overlooked nor failed to propose to remove from the existing text any provisions that are inappropriate, unnecessary or redundant in the absence of the SSM exemption, nor included any such provisions in the proposed new regulatory language. We are specifically seeking comment on whether there are any such provisions that we have inadvertently overlooked or incorporated.

We are also revising the applicability provisions of 40 CFR part 63, subpart HH to clarify requirements regarding PTE determination and the scope of a facility subject to subpart HH. Lastly, we are proposing several editorial corrections and plain language revisions to improve these rules.

C. What are the proposed notification, recordkeeping and reporting requirements for this proposed action?

1. What are the proposed notification, recordkeeping and reporting requirements for the proposed NSPS?

The proposed 40 CFR part 60, subpart OOOO includes new requirements for several operations for which there are no existing Federal standards. Most notably, as discussed in sections V.A and VI.B of this preamble, the proposed NSPS will cover completions and recompletions of hydraulically fractured gas wells. We estimate that over 20,000 completions and recompletions annually will be subject to the proposed requirements. Given the number of these operations, we believe that notification and reporting must be streamlined to the extent possible to minimize undue burden on owners and operators, as well as state, local and tribal agencies. In section V.D of this preamble, we discuss some innovative implementation approaches being considered and seek comment on these and other potential methods of streamlining notification and reporting for well completions covered by the proposed rule.

Owners or operators are required to submit initial notifications and annual reports, and to retain records to assist in documenting that they are complying with the provisions of the NSPS. These notification, recordkeeping and reporting activities include both requirements of the 40 CFR part 60 General Provisions, as well as requirements specific to 40 CFR part 60, subpart OOOO.

Owners or operators of affected facilities (except for pneumatic controller and gas wellhead affected

[5] 40 CFR 63.6(e)(1)(i) requires owners or operators to act according to the general duty to ''operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.'' This general duty to minimize is included in our proposed standard at 40 CFR 63.783(b)(1).

sources) must submit an initial notification within 1 year after becoming subject to 40 CFR part 60, subpart OOOO or by 1 year after the publication of the final rule in the **Federal Register**, whichever is later. For pneumatic controllers, owners and operators are not required to submit an initial notification, but instead are required to report the installation of these affected facilities in their facility's annual report. Owners or operators of wellhead affected facilities (well completions) would also be required to submit a 30-day advance notification of each well completion subject to the NSPS. In addition, annual reports are due 1 year after initial startup date for your affected facility or 1 year after the date of publication of the final rule in the **Federal Register**, whichever is later. The notification and annual reports must include information on all affected facilities owned or operated that were new, modified or reconstructed sources during the reporting period. A single report may be submitted covering multiple affected facilities, provided that the report contains all the information required by 40 CFR 60.5420(b). This information includes general information on the facility (*i.e.*, company name and address, etc.), as well as information specific to individual affected facilities.

For wellhead affected facilities, this information includes details of each well completion during the period, including duration of periods of gas recovery, flaring and venting. For centrifugal compressor affected facilities, information includes documentation that the compressor is fitted with dry seals. For reciprocating compressors, information includes the cumulative hours of operation of each compressor and records of rod packing replacement.

Information for pneumatic device affected facilities includes location and manufacturer specifications of each pneumatic controller installed during the period and documentation that supports any exemption claimed allowing use of high bleed controllers. For controllers installed at gas processing plants, the owner or operator would document the use of non-gas driven devices. For controllers installed in locations other than at gas processing plants, owners or operators would provide manufacturer's specifications that document bleed rate not exceeding 6 cubic feet per hour.

For storage vessel affected facilities, required report information includes information that documents control device compliance, if applicable. For vessels with throughputs below 1 barrel of condensate per day and 21 barrels of crude oil per day, required information also includes calculations or other documentation of the throughput. For onshore gas processing plants, semi-annual reports are required, and include information on number of pressure relief devices, number of pressure relief devices for which leaks were detected and pressure relief devices for which leaks were not repaired, as required in 40 CFR 60.5396 of subpart OOOO.

Records must be retained for 5 years and generally consist of the same information required in the initial notification and annual and semiannual reports.

2. What are the proposed amendments to notification, recordkeeping and reporting requirements for the NESHAP?

We are proposing to revise certain recordkeeping requirements of 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH. Specifically, we are proposing that facilities using carbon adsorbers as a control device keep records of their carbon replacement schedule and records for each carbon replacement. In addition, owners and operators are required to keep records of the occurrence and duration of each malfunction or operation of the air pollution control equipment and monitoring equipment.

In addition, in conjunction with the proposed MACT standards for small glycol dehydration units and storage vessels that do not have the PFE in the proposed amendment to 40 CFR part 63, subpart HH, we are proposing that owners and operators of affected small glycol dehydration units and storage vessels submit an initial notification within 1 year after becoming subject to subpart HH or by 1 year after the publication of the final rule in the **Federal Register**, whichever is later.

Similarly, in conjunction with the proposed MACT standards for small glycol dehydration units in the proposed 40 CFR part 63, subpart HHH amendments, we are proposing that owners and operators of small glycol dehydration units submit an initial notification within 1 year after becoming subject to subpart HHH or by 1 year after the publication of the final rule in the **Federal Register**, whichever is later. Affected sources under either 40 CFR part 63, subpart HH or subpart HHH that plan to be area sources by the compliance dates will be required to submit a notification describing their schedule for the actions planned to achieve area source status.

The proposed amendments to the NESHAP also include additional requirements for the contents of the periodic reports. For both 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH, we are proposing that the periodic reports also include periodic test results and information regarding any carbon replacement events that occurred during the reporting period.

3. *How is information submitted using the Electronic Reporting Tool (ERT)?*

Performance test data are an important source of information that the EPA uses in compliance determinations, developing and reviewing standards, emission factor development, annual emission rate determinations and other purposes. In these activities, the EPA has found it ineffective and time consuming, not only for owners and operators, but also for regulatory agencies, to locate, collect and submit performance test data because of varied locations for data storage and varied data storage methods. In recent years, though, stack testing firms have typically collected performance test data in electronic format, making it possible to move to an electronic data submittal system that would increase the ease and efficiency of data submittal and improve data accessibility.

Through this proposal, the EPA is taking a step to increase the ease and efficiency of data submittal and improve data accessibility. Specifically, the EPA is proposing that owners and operators of oil and natural gas sector facilities submit electronic copies of required performance test reports to the EPA's WebFIRE database. The WebFIRE database was constructed to store performance test data for use in developing emission factors. A description of the WebFIRE database is available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.*

As proposed above, data entry would be through an electronic emissions test report structure called the *Electronic Reporting Tool* (ERT). The ERT will be able to transmit the electronic report through the EPA's Central Data Exchange network for storage in the WebFIRE database making submittal of data very straightforward and easy. A description of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/ert_tool.html.*

The proposal to submit performance test data electronically to the EPA would apply only to those performance tests conducted using test methods that will be supported by the ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at *http://*

www.epa.gov/ttn/chief/ert/ert_tool.html. We believe that industry would benefit from this proposed approach to electronic data submittal. Having these data, the EPA would be able to develop improved emission factors, make fewer information requests, and promulgate better regulations.

One major advantage of the proposed submittal of performance test data through the ERT is a standardized method to compile and store much of the documentation required to be reported by this rule. Another advantage is that the ERT clearly states testing information that would be required. Another important benefit of submitting these data to the EPA at the time the source test is conducted is that it should substantially reduce the effort involved in data collection activities in the future. When the EPA has performance test data in hand, there will likely be fewer or less substantial data collection requests in conjunction with prospective required residual risk assessments or technology reviews. This would result in a reduced burden on both affected facilities (in terms of reduced manpower to respond to data collection requests) and the EPA (in terms of preparing and distributing data collection requests and assessing the results).

State, local and tribal agencies could also benefit from more streamlined and accurate review of electronic data submitted to them. The ERT would allow for an electronic review process rather than a manual data assessment making review and evaluation of the source provided data and calculations easier and more efficient. Finally, another benefit of the proposed data submittal to WebFIRE electronically is that these data would greatly improve the overall quality of existing and new emissions factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, the EPA would be able to ensure that emission factors, when updated, represent the most current range of operational practices. In summary, in addition to supporting regulation development, control strategy development and other air pollution control activities having an electronic database populated with performance test data would save industry, state, local, tribal agencies and the EPA significant time, money and effort while also improving the quality of emission inventories and, as a result, air quality regulations.

D. What are the innovative compliance approaches being considered?

Given the potential number and diversity of sources affected by this action, we are exploring optional approaches to provide the regulated community, the regulators and the public a more effective mechanism that maximizes compliance and transparency while minimizing burden.

Under a traditional approach, owners or operators would provide notifications and keep records of information required by the NSPS. In addition, they would certify compliance with the NSPS as part of a required annual report that would include compliance-related information, such as details of each well completion event and information documenting compliance with other requirements of the NSPS. The EPA, state or local agency would then physically inspect the affected facilities and/or audit the records retained by the owner or operator. As an alternative to the traditional approach, we are seeking an innovative way to provide for more transparency to the public and less burden on the regulatory agencies and owners and operators, especially as it relates to modification of existing sources through recompletions of hydraulically fractured gas wells. These innovative approaches would provide compliance assurance in light of the absence of requirements for CAA title V permitting of non-major sources.

Section V.E of this preamble discusses permitting implications associated with the NSPS and presents a proposed rationale for exempting non-major sources subject to the NSPS from title V permitting requirements. As discussed in sections V.A, V.C and VI.B of this preamble, the proposed NSPS will cover completions and recompletions of hydraulically fractured gas wells. We estimate that over 20,000 completions and recompletions annually will be subject to the proposed requirements. As a result, we believe that notification and reporting associated with well completions must be streamlined to the extent possible to minimize undue burden on owners and operators, as well as state, local and tribal agencies. Though the requirements being proposed here are based on the traditional approach to compliance and do not include specific regulatory provisions for innovative compliance tools, we have included discussions below that describe how some of these optional tools could work, and we will consider providing for such options in the final action. Further, we request comments and suggestions on all aspects of the innovative compliance approaches discussed below and how they may be implemented appropriately. We are seeking comment regarding the scope of application of one or more of these approaches, *i.e.,* which provisions of the standards being proposed here would be suitable for specific compliance approaches, and whether the approaches should be alternatives to the requirements in the regulations.

The guiding principles we are following in considering these approaches to compliance are: (1) Simplicity and ease of understanding and implementation; (2) transparency and public accessibility; (3) electronic implementation where appropriate; and (4) encouragement of compliance by making compliance easier than noncompliance. Below are some tools that, when used in tandem with emissions limits and operational standards, the Agency believes could both assure compliance and transparency, while minimizing burden on affected sources and regulatory agencies.

1. Registration of Wells and Advance Notification of Planned Completions

Although the proposed NSPS will not require approval to drill or complete wells, it is important that regulatory agencies know when completions of hydraulically fractured wells are to be performed. Notification should occur sufficiently in advance to allow for inspections or audits to certify or verify that the operator will have in place and use the appropriate controls during the completion. To that end, the proposed NSPS requires a 30-day advance notification of each completion or recompletion of a hydraulically fractured gas well. The advance notification would require that owners or operators provide the anticipated date of the completion, the geographic coordinates of the well and identifying information concerning the owner or operator and responsible company official. We believe this notification requirement serves as the registration requirement and could be streamlined through optional electronic reporting with web-based public access or other methods. We seek comment on potential methodologies that would minimize burden on operators, while providing timely and useful information for regulators and the public. We also solicit comment on provisions for a follow-up notification one or two days before an impending completion via telephone or by electronic means, since it is difficult to predict exactly when a well will be ready for completion a month in advance. However, we would expect an owner or operator to provide the follow-up notification only in cases where the completion date was expected to deviate from the original date provided. We ask for suggestions regarding how much advance notification is needed and the most effective method of providing sufficient and accurate advance notification of well completions.

2. Third Party Verification

To complement the annual compliance certification required under the proposed NSPS, we are considering and seeking comment on the potential use of third party verification to assure compliance. Since the emission sources in the oil and natural gas sector, especially well completions, are widely geographically dispersed (often in very remote locations), compliance assurance can be very difficult and burdensome for state, local and tribal agencies and EPA permitting staff, inspectors and compliance officers. Additionally, we believe that verification of the data collection, compilation and calculations by an independent and impartial third party could facilitate the demonstration of compliance for the public. Verification of emissions data can also be beneficial to owners and operators by providing certainty of compliance status.

As mentioned above, notification and reporting requirements associated with well completions are likely applications for third party verification used in tandem with the required annual compliance certification. The third party verification program could be used in a variety of ways to ease regulatory burden on the owners and operators and to leverage compliance assurance efforts of the EPA and state, local and tribal agencies. The third party agent could serve as a clearinghouse for notifications, records and annual compliance certifications submitted by owners and operators. This would provide online access to completion information by regulatory agencies and the public. Having notifications submitted to the clearinghouse would relieve state, local and tribal agencies of the burden of receiving thousands of paper or e-mail well completion notifications each year, yet still provide them quick access to the information. Using a third party agent, it is possible that notifications of well completions could be submitted with an advance period much less than 30 days that could make a 2 day follow-up notification unnecessary. The clearinghouse could also house information on past completions and copies of compliance certifications. We seek comment on whether annual reports for well completions would be needed if a suitable third party verification program was in place and already housed that same information. We also solicit comment on the range of potential activities the third party verification program could handle with regard to well completions.

In this proposed action, there are also provisions for applying third party verification to the required electronic reporting using the ERT (see section V.C.3 above for a discussion of the ERT). As stated above, all sources must use the ERT to submit all performance test reports (required in 40 CFR parts 60, 61 and 63) to the EPA. There is an option in the ERT for state, local and tribal agencies to review and verify that the information submitted to the EPA is truthful, accurate and complete. Third party verifiers could be contractors or other personnel familiar with oil and natural gas exploration and production. We are seeking comment on appropriate third party reviewers and qualifications and registration requirements under such a program. We want to state clearly here that third party verification would not supersede or substitute for inspections or audit of data and information by state, local and tribal agencies and the EPA.

Potential issues with third party verification include costs incurred by industry and approval of third party verifiers. The cost of third party verification would be borne by the affected industries. We are seeking comment on whether third party verification paid for by industry would result in impartial, accurate and complete data information. The EPA, working with state, local and tribal agencies and industry, would expect to develop guidance for third party verifiers. We are seeking comment on whether or not the EPA should approve third party verifiers.

3. Electronic Reporting Using Existing Mechanisms

The proposed 40 CFR part 60, subpart OOOO and final Greenhouse Gas (GHG) Mandatory Reporting Rule, 40 CFR part 98, subpart W, provide details on flare and vented emission sources and how to estimate their emissions. We solicit comment on requiring sources to electronically submit their emissions data for the oil and gas rules proposed here. The EPA's *Electronic Greenhouse Gas Reporting Tool* (e-GGRT) for 40 CFR part 98, subpart W, while used to report emissions at the emissions source level (*e.g.,* well completions, well unloading, compressors, gas plant leaks, etc.), will aggregate emissions at the basin level for e-reporting purposes. As a result, it may be difficult to merge reporting under NSPS subpart OOOO with GHG Reporting Rule subpart W methane reporting, especially if manual reporting is used. However, since the operator would have these emissions details at the individual well level (because that will be how they would develop their basin-wide estimates), we do not believe it would be a significant burden to require owners or operators to report the data they already have for subpart W in an ERT for NSPS and NESHAP compliance purposes. However, if the e-GGRT is not structured to provide for reporting of other pollutants besides GHG (*e.g.,* VOC and HAP), then there may be some modification of the database required to accommodate the other pollutants.

4. Provisions for Encouraging Innovative Technology

The oil and natural gas industry has a long history of innovation in developing new exploration and production methods, along with techniques to minimize product losses and reduce adverse environmental impacts. These efforts are often undertaken with tremendous amounts of research, including pilot applications at operating facilities in the field. Absent regulation, these developmental activities, some of which ultimately are not successful, can proceed without risk of violation of any standards. However, as more emission sources in this source category are covered by regulation, as in the case of the action being proposed here, there likely will be situations where innovation and development of new control techniques potentially could be stifled by risk of violation.

We believe it is important to facilitate, not hinder, innovation and continued development of new technology that can result in enhanced environmental performance of facilities and sources affected by the EPA's regulations. However, any approaches to accommodate technology development must be designed and implemented in accordance with the CAA and other statutes. We seek comment on approaches that may be suitable for allowing temporary field testing of technology in development. These approaches could include not only established procedures under the CAA and its implementing regulations, but new ways to apply or interpret these provisions to avoid impeding innovation while remaining environmentally responsible and legal.

E. How does the NSPS relate to permitting of sources?

1. How does this action affect permitting requirements?

The proposed rules do not change the Federal requirements for determining whether oil and gas sources are major sources for purposes of nonattainment major New Source Review (NSR), prevention of significant deterioration, CAA title V, or HAP major sources pursuant to CAA section 112. Specifically, if an owner or operator is not currently required to get a major NSR or title V permit for oil and gas sources, including well completions, it would not be required to get a major NSR or title V permit as a result of these proposed standards. EPA-approved state and local major source permitting programs would not be affected. That is, state and local agencies with EPA-approved programs will still make case-by-case major source determinations for purposes of major NSR and title V, relying on the regulatory criteria, as explained in the McCarthy Memo.[6] Consistent with the McCarthy Memo, whether or not a permitting authority should aggregate two or more pollutant-emitting activities into a single major stationary source for purposes of NSR and title V remains a case-by-case decision in which permitting authorities retain the discretion to consider the factors relevant to the specific circumstances of the permitted activities.

In addition, the proposed standards would not change the requirements for determining whether oil and gas sources are subject to minor NSR. Nor would the proposed standards affect existing EPA-approved state and local minor NSR rules, as well as policies and practices implementing those rules. Many state and local agencies have already adopted minor NSR permitting programs that provide for control of emissions from relatively small emission sources, including various pieces of equipment used in oil and gas fields. State and local agencies would be able to continue to use any EPA-approved General Permits, Permits by Rule, and other similar streamlining mechanisms to permit oil and gas sources such as wells. We recently promulgated the final Tribal Minor NSR rules for use in issuing minor issue permits on tribal lands, where many oil and gas sources are located.

The proposed standards will lead to better control of and reduced emissions from oil and gas production, gas processing and transmission and storage, including wells. In some instances, we anticipate that complying with the NSPS would reduce emissions from these smaller sources to below the minor source applicability thresholds. In those cases, sources that would otherwise have been subject to minor NSR would not need to get minor NSR permits as a result of being subject to the NSPS. Accordingly, the number of minor NSR permits, as well as the Agency resources needed to issue them, would be reduced.

We expect the emission reductions achieved from the proposed standards to significantly improve ozone nonattainment problems in areas where oil and gas production occurs. Strategies for attaining and maintaining the national ambient air quality standards (NAAQS) are a function of SIP (or, in some instances, Federal Implementation Plans and Tribal Implementation Plans) pursuant to CAA section 110. In developing plans to attain and maintain the NAAQS, EPA works with state, local or Tribal agencies to account for growth and develop overall control strategies that address existing and expected emissions. The reductions achieved by the standards will make it easier for state and local agencies to plan for and to attain and maintain the ozone NAAQS.

2. How does this action affect applicability of CAA title V?

Under section 502(a) of the CAA, the EPA may exempt one or more non-major sources [7] subject to CAA section 111 (NSPS) standards from the requirements of title V if the EPA finds that compliance with such requirements is ''impracticable, infeasible, or unnecessarily burdensome'' on such sources. The EPA determine whether to exempt a non-major source from title V at the time we issue the relevant CAA section 111 standards (40 CFR 70.3(b)(2)). We are proposing in this action to exempt from the requirements of title V non-major sources that would be subject to the proposed NSPS for well completions, pneumatic devices, compressors, and/or storage vessels. These non-major sources (hereinafter referred to as the ''oil and gas NSPS non-major sources'') would not be required to obtain title V permits solely as a result of being subject to one or more of the proposed NSPS identified above (hereinafter referred to as the ''proposed NSPS''); however, if they were otherwise required to obtain title V permits, such requirement(s) would not be affected by the proposed exemption.

Consistent with the statute, the EPA believes that compliance with title V permitting is ''unnecessarily burdensome'' for the oil and gas NSPS non-major sources. The EPA's inquiry into whether this criterion was satisfied is based primarily upon consideration of the following four factors: (1) Whether title V would result in significant improvements to the compliance requirements that we are proposing for the oil and gas NSPS affected non-major sources; (2) whether title V permitting would impose a significant burden on these non-major sources and whether that burden would be aggravated by any difficulty these sources may have in obtaining assistance from permitting agencies; (3) whether the costs of title V permitting for these non-major sources would be justified, taking into consideration any potential gains in compliance likely to occur for such sources; and (4) whether there are implementation and enforcement programs in place that are sufficient to assure compliance with the proposed Oil and Natural Gas NSPS without relying on title V permits. Not all of the four factors must weigh in favor of an exemption. See 70 FR 75320, 75323 (Title V Exemption Rule). Instead, the factors are to be considered in combination and the EPA determines whether the factors, taken together, support an exemption from title V for the oil and gas non-major sources. Additionally, consistent with the guidance provided by the legislative history of CAA section 502(a),[8] we considered whether exempting the Oil and Natural Gas NSPS non-major sources would adversely affect public health, welfare or the environment. The first factor is whether title V would result in significant improvements to the compliance requirements in the proposed NSPS. A finding that title V would not result in significant improvements to the compliance requirements in the proposed NSPS would support a conclusion that title V permitting is ''unnecessary'' for non-

[6] *Withdrawal of Source Determinations for Oil and Gas Industries,* September 22, 2009. This memo continues to articulate the Agency's interpretation for major NSR and title V permitting of oil and gas sources.

[7] CAA section 502(a) prohibits title V exemption for any major source, which is defined in CAA section 501(2) and 40 CFR 70.2.

[8] The legislative history of section 502(a) suggests that EPA should not grant title V exemptions where doing so would adversely affect public health, welfare or the environment. (See Chafee-Baucus Statement of Senate Managers, Environment and Natural Resources Policy Division 1990 CAA Leg. Hist. 905, Compiled November 1993.)

major sources subject to the Oil and Natural Gas Production NSPS.

One way that title V may improve compliance is by requiring monitoring (including recordkeeping designed to serve as monitoring) to assure compliance with permit terms and conditions reflecting the emission limitations and control technology requirements imposed in the standard. See 40 CFR 70.6(c)(1) and 40 CFR 71.6(c)(1). The ''periodic monitoring'' provisions of 40 CFR 70.6(a)(3)(i)(B) and 40 CFR 71.6(a)(3)(i)(B) require new monitoring to be added to the permit when the underlying standard does not already require ''periodic testing or instrumental or noninstrumental monitoring (which may consist of recordkeeping designed to serve as monitoring).'' In addition, title V imposes a number of recordkeeping and reporting requirements that may be important for assuring compliance. These include requirements for a monitoring report at least every 6 months, prompt reports of deviations, and an annual compliance certification. See 40 CFR 70.6(a)(3) and 40 CFR 71.6(a)(3), 40 CFR 70.6(c)(1) and 40 CFR 71.6(c)(1), and 40 CFR 70.6(c)(5) and 40 CFR 71.6(c)(5). To determine whether title V permits would add significant compliance requirements to the proposed NSPS, we compared the title V monitoring, recordkeeping and reporting requirements mentioned above to those requirements proposed for the Oil and Natural Gas NSPS affected facilities.

For wellhead affected facilities (well completions), the proposed NSPS would require (1) 30-day advance notification of each well completion to be performed; (2) noninstrumental monitoring, which is achieved through documentation and recordkeeping of procedures followed during each completion, including total duration of the completion event, amount of time gas is recovered using reduced emission completion techniques, amount of time gas is combusted, amount of time gas is vented to the atmosphere and justification for periods when gas is combusted or vented rather than being recovered; (3) reports of cases where well completions were not performed in compliance with the NSPS; (4) annual reports that document all completions performed during the reporting period (a single report may be used to document multiple completions conducted by a single owner or operator during the reporting period); and (5) annual compliance certifications submitted with the annual report.

These monitoring, recordkeeping and reporting requirements in the proposed NSPS for well completions are sufficient to ensure that the Administrator, the state, local and tribal agencies and the public are aware of completion events before they are performed to provide opportunity for inspection. Sufficient documentation would also be required to be retained and reported to the Administrator to assure compliance with the NSPS for well completions. In light of the above, we have determined that additional monitoring through title V is not needed and that the monitoring, recordkeeping and reporting requirements described above are sufficient to assure compliance with the proposed requirements for well completions.

With respect to storage vessels, the proposed NSPS would require 95-percent control of VOC emissions. The proposed standard could be met by a vapor recovery unit, a flare control device or other control device. The proposed NSPS would require an initial performance test followed by continuous monitoring of the control device used to meet the 95-percent control. We believe that the monitoring requirements described above are sufficient to assure compliance with the proposed NSPS for storage vessels and, therefore, additional monitoring through title V is not needed. In addition to monitoring, as part of the first factor, we have considered the extent to which title V could potentially enhance compliance through recordkeeping or reporting requirements. The proposed NSPS would require (1) construction, startup and modification notifications, as required by 40 CFR 60.7(a); and (2) annual reports that identify all storage vessel affected facilities of the owner or operator and documentation of periods of non-compliance. The proposed NSPS would also require records documenting liquid throughput of condensate or crude oil (to determine applicability), as provided for in the proposed rule. Recordkeeping would also include records of the initial performance test and other information that document compliance with applicable emission limit. These requirements are similar to those under title V. In light of the above, we believe that the monitoring, recordkeeping and reporting requirements described above are sufficient to assure compliance with the proposed NSPS for storage vessels.

For pneumatic controllers, centrifugal compressors and reciprocating compressors, the proposed NSPS are in the form of operational, work practice or equipment standards.[9] For each of these affected facilities, the proposed NSPS would require: (1) Construction, startup and modification notifications, as required by 40 CFR 60.7(a); (2) annual reports; (3) for each pneumatic controller installed or modified (including replacement of an existing controller), records of location and date of installation and documentation that each controller emits no more than the applicable emission limit or is exempt (with rationale for the exemption); (4) for each centrifugal compressor, records that document that each new or modified compressor is equipped with dry seals; and (5) for each new or modified reciprocating compressor, records of rod packing replacement, including elapsed operating hours since the previous rod packing installation.

For these other affected sources described above, the proposed NSPS provide monitoring in the form of recordkeeping (as described above) that would assure compliance with the proposed operational, work practice or equipment standards. Monitoring by means other than recordkeeping would not be practical or appropriate for these standards. Records are required to ensure that these standards and practices are followed. We believe that the monitoring, recordkeeping and reporting requirements described above are sufficient to assure compliance with the proposed NSPS for pneumatic controllers and compressors.

We acknowledge that title V might provide for additional compliance requirements for these non-major sources, but we have determined, as explained above, that the monitoring, recordkeeping and reporting requirements in this proposed NSPS are sufficient to assure compliance with the proposed standards for well completions, storage vessels, pneumatic controllers and compressors. Further, given the nature of some of the operations and the types of the requirements at issue, the additional compliance requirements under title V would not significantly improve the compliance requirements in this proposed NSPS. For instance, well completions occur over a very short period (generally 3 to 10 days), and the proposed NSPS for pneumatic controllers and centrifugal compressors can be met by simply installing the equipment that meet the proposed emission limit; therefore, the semi-annual reporting requirement under title V would not improve compliance with

[9] The proposed numeric standards for pneumatic controllers reflect the use of specific equipment (either non-gas driven device or low-bleed device).

these proposed NSPS and, in fact, may seem inappropriate for such short term operations.

For the reasons stated above, we believe that title V would not result in significant improvements to the compliance requirements that are provided in this proposed NSPS. Therefore, the first factor supports a conclusion that title V permitting is ''unnecessary'' for non-major sources subject to the Oil and Natural Gas NSPS.

The second factor we considered is whether title V permitting would impose significant burdens on the oil and natural gas NSPS non-major sources and whether that burden would be aggravated by any difficulty these sources may have in obtaining assistance from permitting agencies. Subjecting any source to title V permitting imposes certain burdens and costs that do not exist outside of the title V program. EPA estimated that the average cost of obtaining and complying with a title V permit was $65,700 per source for a 5-year permit period, including fees. See Information Collection Request (ICR) for Part 70 Operating Permit Regulations, January 2007, EPA ICR Number 1587.07. EPA does not have specific estimates for the burdens and costs of permitting the oil and gas NSPS non-major sources; however, there are certain activities associated with the 40 CFR part 70 and 40 CFR part 71 rules. These activities are mandatory and impose burdens on any facility subject to title V. They include reading and understanding permit program regulations; obtaining and understanding permit application forms; answering follow-up questions from permitting authorities after the application is submitted; reviewing and understanding the permit; collecting records; preparing and submitting monitoring reports; preparing and submitting prompt deviation reports, as defined by the state, which may include a combination of written, verbal and other communication methods; collecting information, preparing and submitting the annual compliance certification; preparing applications for permit revisions every 5 years; and, as needed, preparing and submitting applications for permit revisions. In addition, although not required by the permit rules, many sources obtain the contractual services of consultants to help them understand and meet the permitting program's requirements. The ICR for 40 CFR part 70 provides additional information on the overall burdens and costs, as well as the relative burdens of each activity described here. Also, for a more comprehensive list of requirements imposed on 40 CFR part 70 sources (hence, burden on sources), see the requirements of 40 CFR 70.3, 40 CFR 70.5, 40 CFR 70.6, and 40 CFR 70.7. The activities described above, which are quite extensive and time consuming, would be a significant burden on the non-major sources that would be subject to the proposed NSPS, in particular for well completion and/or pneumatic devices, considering the short duration of a well completion and the one time equipment installation of a pneumatic controller for meeting the proposed NSPS. Furthermore, some of the non-major sources that would be subject to the proposed NSPS may be small entities that may lack the technical resources and, therefore, need assistance from the permitting authorities to comply with the title V permitting requirements. Based on our projections, over 20,000 well completions (for both new hydraulically fractured gas wells and for existing gas wells that are subsequently fractured or re-fractured) will be performed each year. For pneumatic controller affected facilities, we estimate that approximately 14,000 new controllers would be subject to the NSPS each year. Our estimated numbers of affected facilities that would be subject to the proposed NSPS for storage vessels and compressors are smaller (around 500 compressors and 300 storage vessels). Although we do not know the total number of non-major sources that would be subject to the proposed NSPS, based on the estimated numbers of affected facilities, we anticipate a significant increase in the number of permit applications that permitting authorities would have to process each year. This significant burden on the permitting authorities raises a concern with the potential difficulty or delay that the small entities may face in obtaining sufficient assistance from the permitting authorities.

The third factor we considered is whether the costs of title V permitting for these area sources would be justified, taking into consideration any potential gains in compliance likely to occur for such sources. We concluded, in considering the first factor, that the monitoring, recordkeeping and reporting requirements in this proposed NSPS assure compliance with the proposed standards, that title V would not result in significant improvement to these compliance requirements and, that, in some instances, certain title V compliance requirements may not be appropriate. In addition, as discussed above in our consideration of the second factor, we have concerns with the potential burdens that title V may impose on these sources. In addition, below in our consideration of the fourth factor, we find that there are adequate implementation and enforcement programs in place to assure compliance with the proposed NSPS. In light of the above, we find that the costs of title V permitting are not justified for the sources we propose to exempt. Accordingly, the third factor supports title V exemption for the oil and gas NSPS non-major sources.

The fourth factor we considered is whether there are implementation and enforcement programs in place that are sufficient to assure compliance with the proposed NSPS for oil and gas sources without relying on title V permits. The CAA provides States the opportunity to take delegation of NSPS. Before the EPA will delegate the program, the EPA will evaluate the state programs to ensure that states have adequate capability to enforce the CAA section 111 regulations and provide assurances that they will enforce the NSPS. In addition, EPA retains authority to enforce this NSPS anytime under CAA sections 111, 113 and 114. Accordingly, we can enforce the monitoring, recordkeeping and reporting requirements, which, as discussed under the first factor, are adequate to assure compliance with this NSPS. Also, states and the EPA often conduct voluntary compliance assistance, outreach and education programs (compliance assistance programs), which are not required by statute. We determined that these additional programs will supplement and enhance the success of compliance with these proposed standards. We believe that the statutory requirements for implementation and enforcement of this NSPS by the delegated states, the EPA and the additional assistance programs described above together are sufficient to assure compliance with these proposed standards without relying on title V permitting.

Our balance of the four factors strongly supports a finding that title V is unnecessarily burdensome for the oil and gas non-major sources. While title V might add additional compliance requirements if imposed, we believe that there would not be significant improvements to the compliance requirements in this proposed rule because the proposed rule requirements are specifically designed to assure compliance with the proposed NSPS and, as explained above, some of the title V requirements may not be appropriate for certain operations and/or proposed standards. We are also concerned with the potential burden that title V may impose on some of these sources. In light of little or no potential gain in compliance if title V were required, we do not believe that the costs of title V permitting is justified in this case. Finally, there are adequate implementation and enforcement programs in place to assure compliance with these proposed standards. Thus, we propose that title V permitting is ''unnecessarily burdensome'' for the oil and gas non-major sources.

In addition to evaluating whether compliance with title V requirements is ''unnecessarily burdensome,'' EPA also considered, consistent with guidance provided by the legislative history of section 502(a), whether exempting oil and gas NSPS non-major sources from title V requirements would adversely affect public health, welfare or the environment. The title V permit program does not impose new substantive air quality control requirements on sources, but instead requires that certain procedural measures be followed, particularly with respect to determining compliance with applicable requirements. As stated in our consideration of factor one, title V would not lead to significant improvements in the compliance requirements for the proposed NSPS. For the reason stated above, we believe that exempting these non-major sources from title V permitting requirements would not adversely affect public health, welfare or the environment.

On the contrary, we are concerned that requiring title V in this case could potentially adversely affect public health, welfare or the environment. As mentioned above, we anticipate a significant increase in the number of permit applications that permitting authorities would have to process each year. Depending on the number of non-major sources that would be subject to this rule, requiring permits for those sources, at least in the first few years of implementation, could potentially adversely affect public health, welfare or the environment by shifting state agencies resources away from assuring compliance for major sources (which cannot be exempt from title V) to issuing new permits for these non-major sources, potentially reducing overall air program effectiveness.

Based on the above analysis, we conclude that title V permitting would be ''unnecessarily burdensome'' for oil and gas NSPS non-major sources. We are, therefore, proposing that these non-major sources be exempt from title V permitting requirements.

VI. Rationale for Proposed Action for NSPS

A. What did we evaluate relative to NSPS?

As noted above, there are two existing NSPS that address emissions from the Oil and Natural Gas source category. These NSPS are relatively narrow in scope, as they address emissions only at natural gas processing plants. Specifically, 40 CFR part 60, subpart KKK addresses VOC emissions from leaking equipment at onshore natural gas processing plants and 40 CFR part 60, subpart LLL addresses SO_2 emissions from natural gas processing plants.

CAA section 111(b)(1)(B) requires the EPA to review and revise, if appropriate, NSPS standards. Accordingly, we evaluated whether the existing NSPS reflect the BSER for the emission sources that they address. This review was conducted by examining currently used, new and emerging control systems and assessing whether they represent advances in emission reduction techniques from those upon which the existing NSPS are based, including advances in LDAR approaches and SO_2 control at natural gas processing plants. For each new or emerging control option identified, we then evaluated emission reductions, costs, energy requirements and non-air quality impacts, such as solid waste generation.

In this package, we have also evaluated whether there were additional pollutants emitted by facilities in the Oil and Natural Gas source category that warrant regulation and for which we have adequate information to promulgate standards of performance. Finally, we have identified additional processes in the Oil and Natural Gas source category for which it may be appropriate to develop performance standards. This would include processes that emit the currently regulated pollutants, VOC and SO_2, as well as any additional pollutants for which we determined regulation to be appropriate.

B. What are the results of our evaluations and proposed actions relative to NSPS?

1. Do the existing NSPS reflect the BSER for sources covered?

Consistent with our obligations under CAA section 111(b), we evaluated whether the control options reflected in the current NSPS for the Oil and Natural Gas source category still represent BSER. To evaluate the BSER options for equipment leaks, we reviewed EPA's current LDAR programs, the Reasonably Available Control Technology (RACT)/ Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database, and emerging technologies that have been identified by partners in the Natural Gas STAR program.

The current NSPS for equipment leaks of VOC at natural gas processing plants (40 CFR part 60, subpart KKK) requires compliance with specific provisions of 40 CFR part 60, subpart VV, which is a LDAR program, based on the use of EPA Method 21 to identify equipment leaks. In addition to the subpart VV requirements, we reviewed the LDAR requirements in 40 CFR part 60, subpart VVa. This LDAR program is considered to be more stringent than the subpart VV requirements, because it has lower component leak threshold definitions and more frequent monitoring, in comparison to the subpart VV program. Furthermore, subpart VVa requires monitoring of connectors, while subpart VV does not. We also reviewed options based on optical gas imaging.

As mentioned above, the currently required LDAR program for natural gas processing plants (40 CFR part 60, subpart KKK) is based on EPA Method 21, which requires the use of an organic vapor analyzer to monitor components and to measure the concentration of the emissions in identifying leaks. We recognize that there have been advancements in the use of optical gas imaging to detect leaks from these same types of components. These instruments do not yet provide a direct measure of leak concentrations. The instruments instead provide a measure of a leak relative to an instrument specific calibration point. Since the promulgation of 40 CFR part 60, subpart KKK (which requires Method 21 leak measurement monthly), the EPA has updated the 40 CFR part 60 General Provisions to allow the use of advanced leak detection tools, such as optical gas imaging and ultrasound equipment as an alternative to the LDAR protocol based on Method 21 leak measurements (see 40 CFR 60.18(g)). The alternative work practice allowing use of these advanced technologies includes a provision for conducting a Method 21-based LDAR check of the regulated equipment annually to verify good performance.

In our review, we evaluated 4 options in considering BSER for VOC equipment leaks at natural gas processing plants. One option we evaluated consists of changing from a 40 CFR part 60, subpart VV-level program, which is what 40 CFR part 60, subpart KKK currently requires, to a 40 CFR part 60, subpart VVa program, which applies to new synthetic organic chemical plants after 2006. Subpart VVa lowers the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm, and requires the monitoring of connectors. In our analysis of these impacts, we estimated that, for a typical natural gas processing plant, the incremental cost effectiveness of changing from the current subpart VV-level program to a subpart VVa-level program using Method 21 is $3,352 per ton of VOC reduction.

In evaluating 40 CFR part 60, subpart VVa-level LDAR at processing plants, we also analyzed separately the individual types of components (valves, connectors, pressure relief devices and open-ended lines) to determine cost effectiveness for individual components. Detailed discussions of these component-by-component analyses are included in the TSD in the docket. Cost effectiveness ranged from $144 per ton of VOC (for valves) to $4,360 per ton of VOC (for connectors), with no change in requirements for pressure relief devices and open-ended lines.

Another option we evaluated for gas processing plants was the use of optical gas imaging combined with an annual EPA Method 21 check (*i.e.,* the alternative work practice for monitoring equipment for leaks at 40 CFR 60.18(g)). We had previously determined that the VOC reduction achieved by this combination of optical gas imaging and Method 21 would be equivalent to reductions achieved by the 40 CFR part 60, subpart VVa-level program. Based on that emission reduction level, we determined the cost effectiveness of this option to be $6,462 per ton of VOC reduction. This analysis is based on the facility purchasing an optical gas imaging system costing $85,000. However, we identified at least one manufacturer who rents the optical gas imaging systems. That manufacturer rents the optical gas imaging system for $3,950 per week. Using this rental cost in place of the purchase cost, the VOC cost effectiveness of the monthly optical gas imaging combined with annual Method 21 checks is $4,638 per ton of VOC reduction.[10] A third option we evaluated consisted of monthly optical gas imaging without an annual Method 21 check. We estimated the annual cost of the monthly optical gas imaging LDAR program to be $76,581, based on camera purchase, or $51,999, based on camera rental. However, because we were unable to estimate the VOC emissions achieved by an optical imaging program alone, we were unable to estimate the cost effectiveness of this option.

Finally, we evaluated a fourth option similar to the third option, except that the optical gas imaging would be performed annually rather than monthly. For this option, we estimated the annual cost to be $43,851, based on camera purchase, or $18,479, based on camera rental.

We request comment on the applicability of an LDAR program based solely on the use of optical gas imaging. Of most use to us would be information on the effectiveness of this and, potentially, other advanced measurement technologies, to detect and repair small leaks on the same order or smaller than specified in the 40 CFR part 60, subpart VVa equipment leak requirements and the effects of increased frequency of and associated leak detection, recording and repair practices.

Because we could not estimate the cost effectiveness of options 3 and 4, we could not identify either of these two options as BSER for reducing VOC leaks at gas processing plants. Because options 1 and 2 have achieved equivalent VOC reduction and are both cost effective, we believe that both options 1 and 2 reflect BSER for LDAR for natural gas processing plants. As mentioned above, option 1 is the LDAR in 40 CFR part 60, subpart VVa and option 2 is the alternative work practice at 40 CFR 60.18(g) and is already available to use as an alternative to subpart VVa LDAR. Therefore, we propose that the NSPS for equipment leaks of VOC at gas processing plants be revised to require compliance with the subpart VVa equipment leak requirements.

For 40 CFR part 60, subpart LLL, we reviewed control systems for SO_2 emissions from sweetening units located at natural gas processing plants, including those followed by a sulfur recovery unit. Subpart LLL provides specific standards for SO_2 emission reduction efficiency, on the basis of sulfur feed rate and the sulfur content of the natural gas.

According to available literature, the most widely used process for converting H_2S in acid gases (*i.e.,* H_2S and CO_2) separated from natural gas by a sweetening process (such as amine treating) into elemental sulfur is the Claus process. Sulfur recovery efficiencies are higher with higher concentrations of H_2S in the feed stream due to the thermodynamic equilibrium limitation of the Claus process. The Claus sulfur recovery unit produces elemental sulfur from H_2S in a series of catalytic stages, recovering up to 97-percent recovery of the sulfur from the acid gas from the sweetening process. Further, sulfur recovery is accomplished by making process modifications or by employing a tail gas treatment process to convert the unconverted sulfur compounds from the Claus unit.

We evaluated process modifications and tail gas treatment options when we proposed 40 CFR part 60, subpart LLL. 49 FR 2656, 2659–2660 (1984). As we explained in the preamble to the proposed subpart LLL, control through sulfur recovery with tail gas treatment may not always be cost effective, depending on sulfur feed rate and inlet H_2S concentrations. Therefore, other methods of increasing sulfur recovery via process modifications were evaluated. As shown in the original evaluation, the performance capabilities and costs of each of these technologies are highly dependent on the ratio of H_2S and CO_2 in the gas stream and the total quantity of sulfur in the gas stream being treated. The most effective means of control was selected as BSER for the different stream characteristics. As a result, separate emissions limitations were developed in the form of equations that calculate the required initial and continuous emission reduction efficiency for each plant. The equations were based on the design performance capabilities of the technologies selected as BSER relative to the gas stream characteristics. 49 FR 2656, 2663–2664 (1984). The emission limit for sulfur feed rates at or below 5 long tons per day, regardless of H_2S content, was 79 percent. For facilities with sulfur feed rates above 5 long tons per day, the emission limits ranged from 79 percent at an H_2S content below 10 percent to 99.8 percent for H_2S contents at or above 50 percent.

To review these emission limitations, we performed a search of the RBLC database and state regulations. No state regulations identified had emission limitations more stringent than 40 CFR part 60, subpart LLL. However, the RBLC database search identified two entries with SO_2 emission reductions of 99.9 percent. One entry is for a facility in Bakersfield, California, with a 90 long ton per day sulfur recovery unit followed by an amine-based tail-gas treating unit. The second entry is for a facility in Coden, Alabama, with a sulfur recovery unit with a sulfur feed rate of 280 long tons per day, followed by selective catalytic reduction and a tail gas incinerator. However, neither of these entries contained information regarding the H_2S contents of the feed

[10] Because optical gas imaging is used to view several pieces of equipment at a facility at once to survey for leaks, options involving imaging are not amenable to a component by component analysis.

stream. Because the sulfur recovery efficiency of these large sized plants was greater than 99.8 percent, we reevaluated the original data. Based on the available cost information, it appears that a 99.9-percent efficiency is cost effective for facilities with a sulfur feed rate greater than 5 long tons per day and H_2S content equal to or greater than 50 percent. Based on our review, we are proposing that the maximum initial and continuous efficiency for facilities with a sulfur feed rate greater than 5 long tons per day and an H_2S content equal to or greater than 50 percent be raised to 99.9 percent. We are not proposing to make changes to the equations.

Our search of the RBLC database did not uncover information regarding costs and achievable emission reductions to suggest that the emission limitations for facilities with a sulfur feed rate less than 5 long tons per day or H_2S content less than 50 percent should be modified. Therefore, we are not proposing any changes to the emissions limitations for facilities with sulfur feed rate and H_2S content less than 5 long tons per day and 50 percent, respectively.

2. What pollutants are being evaluated in this Oil and Natural Gas NSPS package?

The two current NSPS for the Oil and Natural Gas source category address emissions of VOC and SO_2. In addition to these pollutants, sources in this source category also emit a variety of other pollutants, most notably, air toxics. As discussed elsewhere in this notice, there are NESHAP that address air toxics from the oil and natural gas sector.

In addition, processes in the Oil and Natural Gas source category emit significant amounts of methane. The 1990–2009 U.S. GHG Inventory estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries) to be 251.55 $MMtCO_2e$ (million metric tons of CO_2-equivalents (CO_2e)).[11] The emissions estimated from well completions and recompletions exclude a significant number of wells completed in tight sand plays, such as the Marcellus, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays (being considered as a planned improvement in development of the 2010 Inventory). This adjustment would increase the 2009 Inventory estimate by 76.74 $MMtCO_2e$. The total methane emissions from Petroleum and Natural Gas Systems, based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus, is 328.29 $MMtCO_2e$. Although this proposed rule does not include standards for regulating the GHG emissions discussed above, we continue to assess these significant emissions and evaluate appropriate actions for addressing these concerns. Because many of the proposed requirements for control of VOC emissions also control methane emissions as a co-benefit, the proposed VOC standards would also achieve significant reduction of methane emissions.

Significant emissions of oxides of nitrogen (NO_X) also occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors that move natural gas through the system, and from combustion of natural gas in heaters and boilers. While these engines, turbines, heaters and boilers are co-located with processes in the oil and natural gas sector, they are not in the Oil and Natural Gas source category and are not being addressed in this action. The NO_X emissions from engines and turbines are covered by the Standards of Performance for Stationary Spark Internal Combustion Engines (40 CFR part 60, subpart JJJJ) and Standards of Performance for Stationary Combustion Turbines (40 CFR part 60, subpart KKKK), respectively.

An additional source of NO_X emissions would be pit flaring of VOC emissions from well completions during periods where REC is not feasible, as would be required under our proposed operational standards for wellhead affected facilities. As discussed below in section VI.B.4 (well completion), pit flaring is the only way we identified of controlling VOC emissions during these periods. Because there is no way of directly measuring the NO_X produced, nor is there any way of applying controls other than minimizing flaring, we propose to allow flaring only when REC is not feasible. We have included our estimates of NO_X formation from pit flaring in our discussion of secondary impacts in section VI.B.4.

3. What emission sources are being evaluated in this Oil and Natural Gas NSPS package?

The current NSPS only cover emissions of VOC and SO_2 from one type of facility in the oil and natural gas sector, which is the natural gas processing plant. This is the only type of facility in the Oil and Natural Gas source category where we would expect SO_2 to be emitted directly, although H_2S contained in sour gas, when oxidized in the atmosphere or combusted in boilers and heaters in the field, forms SO_2 as a product of oxidation. These field boilers and heaters are not part of the Oil and Natural Gas source category and are generally too small to be regulated by the NSPS covering boilers (*i.e.,* they have a heat input of less than 10 million British Thermal Units per hour). However, we may consider addressing them as part of a future sector-based strategy for the oil and natural gas sector.

In addition to VOC emissions from gas processing plants, there are numerous sources of VOC throughout the oil and natural gas sector that are not addressed by the current NSPS. As explained above in section V.A, pursuant to CAA section 111(b), to the extent necessary, we are modifying the listed category to include all segments of the oil and natural gas industry for regulation. We are also proposing VOC standards to cover additional processes at oil and natural gas operations. These include NSPS for VOC from gas well completions, pneumatic controllers, compressors and storage vessels.

We believe that produced water ponds are also a potentially significant source of emissions, but we have only limited information. We, therefore, solicit comments on produced water ponds, particularly in the following subject areas:

(a) We are requesting comments pertaining to methods for calculating emissions. The State of Colorado currently uses a mass balance that assumes 100 percent of the VOC content is emitted to the atmosphere. Water9, an air emissions model, is another option that has some limitations, including poor methanol estimation.

(b) We are requesting additional information on typical VOC content in produced water and any available chemical analyses, including data that could help clarify seasonal variations or differences among gas fields. Additionally, we request data that increase our understanding of how changing process variables or age of wells affect produced water output and VOC content.

(c) We solicit information on the size and throughput capacity of typical evaporation pond facilities and request suggestions on parameters that could be used to define affected facilities or affected sources. We also seek information on impacts of smaller evaporation pits that are co-located with drilling operations, whether those

[11] U.S. EPA. *Inventory of U.S. Greenhouse Gas Inventory and Sinks.* 1990–2009. *http://www.epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_ExecutiveSummary.pdf.*

warrant control and, if so, how controls should be developed.

(d) An important factor is cost of emission reduction technologies, including recovery credits or cost savings realized from recovered salable product. We are seeking information on these considerations as well.

(e) We are also seeking information on any limitations for emission reduction technologies such as availability of electricity, waste generation and disposal and throughput and concentration constraints.

(f) Finally, we solicit information on separator technologies that are able to improve the oil-water separation efficiency.

4. What are the rationales for the proposed NSPS?

We have provided below our rationales for the proposed BSER determinations and performance standards for a number of VOC emission sources in the Oil and Natural Gas source category that are not covered by the existing NSPS. Our general process for evaluating systems of emission reduction for the emission sources discussed below included: (1) Identification of available control measures; (2) evaluation of these measures to determine emission reductions achieved, associated costs, nonair environmental impacts, energy impacts and any limitations to their application; and (3) selection of the control techniques that represent BSER based on the information we considered.

We identified the control options discussed in this package through our review of relevant state and local requirements and mitigation measures developed and reported by the EPA's Natural Gas STAR program. The EPA's Natural Gas STAR program has worked with industry partners since 1993 to identify cost effective measures to reduce emissions of methane and other pollutants from natural gas operations. We relied heavily on this wealth of information in conducting this review. We also identified state regulations, primarily in Colorado and Wyoming, which require mitigation measures for some emission sources in the Oil and Natural Gas source category.

a. NSPS for Well Completions

Well completion activities are a significant source of VOC emissions, which occur when natural gas and non-methane hydrocarbons are vented to the atmosphere during flowback of a hydraulically fractured gas well. Flowback emissions are short-term in nature and occur over a period of several days following fracturing of a new well or refracturing of an existing well. Well completions include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Well recompletions may also include hydraulic fracturing. Hydraulic fracturing is one technique for improving gas production where the reservoir rock is fractured with very high pressure fluid, typically water emulsion with a proppant (generally sand) that ''props open'' the fractures after fluid pressure is reduced. Emissions are a result of the backflow of the fracture fluids and reservoir gas at high volume and velocity necessary to lift excess proppant and fluids to the surface. This multi-phase mixture is often directed to a surface impoundment where natural gas and VOC vapors escape to the atmosphere during the collection of water, sand and hydrocarbon liquids. As the fracture fluids are depleted, the backflow eventually contains more volume of natural gas from the formation. Wells that are fractured generally have great amounts of emissions because of the extended length of the flowback period required to purge the well of the fluids and sand that are associated with the fracturing operation. Along with the fluids and sand from the fracturing operation, the 3- to 10-day flowback period also results in emissions of natural gas and VOC that would not occur in large quantities at oil wells or at natural gas wells that are not fractured. Thus, we estimate that gas well completions involving hydraulic fracturing vent substantially more VOC, approximately 200 times more, than completions not involving hydraulic fracturing. Specifically, we estimate that uncontrolled well completion emissions for a hydraulically fractured gas well are approximately 23 tons of VOC, where emissions for a conventional gas well completion are around 0.12 tons VOC. These estimates are explained in detail in the TSD available in the docket. Based on our review, we believe that emissions from recompletions of previously completed wells that are fractured or refractured to stimulate production or to begin production from a new production horizon are of similar magnitude and composition as emissions from completions of new wells that have been hydraulically fractured.

EPA has based the NSPS impacts analysis on best available emission data. However, we recognize that there is uncertainty associated with our estimates. For both new completions and recompletions, there are a variety of factors that will determine the length of the flowback period and actual volume of emissions such as the number of zones, depth, pressure of the reservoir, gas composition, etc. This variability means there will be some wells which emit more than the estimated emission factor and some wells that emit less.

During our review, we examined information from the Natural Gas STAR program and the Colorado and Wyoming state rules covering well completions. We identified two subcategories of fractured gas wells: (1) Non-exploratory and non-delineation wells; and (2) exploratory and delineation wells. An exploratory well is the first well drilled to determine the presence of a producing reservoir and the well's commercial viability. A delineation well is a well drilled to determine the boundary of a field or producing reservoir. Because exploratory and delineation wells are generally isolated from existing producing wells, there are no gathering lines available for collection of gas recovered during completion operations. In contrast, non-exploratory and non-delineation wells are located where existing, producing wells are connected to gathering lines and are, therefore, able to be connected to a gathering line to collect recovered salable natural gas product that would otherwise be vented to the atmosphere or combusted.

For subcategory 1, we identified ''green'' completion, which we refer to as REC, as an option for reducing VOC emissions during well completions. REC are performed by separating the flowback water, sand, hydrocarbon condensate and natural gas to reduce the portion of natural gas and VOC vented to the atmosphere, while maximizing recovery of salable natural gas and VOC condensate. In some cases, for a portion of the completion operation, such as when CO_2 or nitrogen is injected with the fracture water, initial gas produced is not of suitable quality to introduce into the gathering line due to CO_2 or nitrogen content or other undesirable characteristic. In such cases, for a portion of the flowback period, gas cannot be recovered, but must be either vented or combusted. In practice, REC are often combined with combustion to minimize the amount of gas and condensate being vented. This combustion process is rather crude, consisting of a horizontal pipe downstream of the REC equipment, fitted with a continuous ignition source and discharging over a pit near the wellhead. Because of the nature of the flowback (*i.e.,* with periods of water, condensate, and gas in slug flow), conveying the entire portion of this stream to a traditional flare control device or other control device, such as a vapor recovery unit, is not feasible. These control devices are not designed to accommodate the multiphase flow consisting of water, sand and hydrocarbon liquids, along with the gas and vapor being controlled. Although ''pit flaring'' does not employ a traditional flare control device, and is not capable of being tested or monitored for efficiency due to the multiphase slug flow and intermittent nature of the discharge of gas, water and sand over the pit, it does provide a means of minimizing vented gas and is preferable to venting. Because of the rather large exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (*e.g.,* dry, windy conditions, proximity to residences, etc.). As a result, we are aware that owners and operators may not be able to pit flare unrecoverable gas safely in every case. In some cases, pit flaring may be prohibited by local ordinance.

Equipment required to conduct REC may include tankage, special gas-liquid-sand separator traps and gas dehydration. Equipment costs associated with REC will vary from well to well. Typical well completions last between 3 and 10 days and costs of performing REC are projected to be between $700 and $6,500 per day, including a cost of approximately $3,523 per completion event for the pit flaring equipment. However, there are savings associated with the use of REC because the gas recovered can be incorporated into the production stream and sold. In fact, we estimate that REC will result in an overall net cost savings in many cases.

The emission reductions for a hydraulically fractured well are estimated to be around 22 tons of VOC. Based on an average incremental cost of $33,237 per completion, the cost effectiveness of REC, without considering any cost savings, is around $1,516 per ton of VOC (which we have previously found to be cost effective on average). When the value of the gas recovered (approximately 150 tons of methane per completion) is considered, the cost effectiveness is estimated as an average net savings of $99 per ton VOC reduced, using standard discount rates. We believe that these costs are very reasonable, given the emission reduction that would be achieved. Aside from the potential hazards associated with pit flaring, in some cases, we did not identify any nonair environmental impacts, health or energy impacts associated with REC combined with combustion. However, pit flaring would produce NO_X emissions. Because we believe that these emissions cannot be controlled or measured directly due to the open combustion process characteristic of pit flaring, we used published emission factors (EPA Emission Guidelines AP–42) to estimate the NO_X emissions for purposes of assessing secondary impacts. For category 1 well completions, we estimated that 0.02 tons of NO_X are produced per event. This is based on the assumption that 5 percent of the flowback gas is combusted by the combustion device. The 1.2 tons of VOC controlled during the pit flaring portion of category 1 well completions is approximately 57 times greater than the NO_X produced by pit flaring. Thus, we believe that the benefit of the VOC reduction far outweighs the secondary impact of NO_X formation during pit flaring.

We believe that, based on the analysis above, REC in combination with combustion is BSER for subcategory 1 wells. We considered setting a numerical performance standard for subcategory 1 wells. However, it is not practicable to measure the emissions during pit flaring or venting because the gas is discharged over the pit along with water and sand in multiphase slug flow. Therefore, we believe it is not feasible to set a numerical performance standard. Pursuant to section 111(h)(2) of the CAA, we are proposing an operational standard for subcategory 1 wells that would require a combination of REC and pit flaring to minimize venting of gas and condensate vapors to the atmosphere, with provisions for venting in lieu of pit flaring for situations in which pit flaring would present safety hazards or for periods when the flowback gas is noncombustible due to high concentrations of nitrogen or CO_2. The proposed operational standard would be accompanied by requirements for documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion.

We recognize that there is heterogeneity in well operations and costs, and that while RECs may be cost-effective on average, they may not be for all operators. Nonetheless, EPA is proposing to require an operational standard rather than a performance-based standard (*e.g.,* requiring that some percentage of emissions be flared or captured), because we believe there are no feasible ways for operators to measure emissions with enough certainty to demonstrate compliance with a performance-based standard for REC in combination with pit flaring. The EPA requests comment on this and seeks input on whether alternative approaches to requiring REC for all operators with access to pipelines may exist that would allow operators to meet a performance-based standard if they can demonstrate that an REC is not cost effective.

We have discussed above certain situations where unrecoverable gas would be vented because pit flaring would present a fire hazard or is infeasible because gas is noncombustible due to high concentrations of nitrogen or CO_2. We solicit comment on whether there are other such situations where flaring would be unsafe or infeasible, and potential criteria that would support venting in lieu of pit flaring. In addition, we learned that coalbed methane reservoirs may have low pressure, which would present a technical barrier for performing a REC because the well pressure may not be substantial enough to overcome gathering line pressure. In addition, we identified that coalbed methane wells often have low to almost no VOC emissions, even following the hydraulic fracturing process. We solicit comment on criteria and thresholds that could be used to exempt some well completion operations occurring in coalbed methane reservoirs from the requirements for subcategory 1 wells.

Of the 25,000 new and modified fractured gas wells completed each year, we estimate that approximately 3,000 to 4,000 currently employ reduced emission completion. We expect this number to increase to over 21,000 REC annually as operators comply with the proposed NSPS. We estimate that approximately 9,300 new wells and 12,000 existing wells will be fractured or refractured annually that would be subject to subcategory 1 requirements under the NSPS. We believe that there will be a sufficient supply of REC equipment available by the time the NSPS becomes effective. However, energy availability could be affected if a shortage of REC equipment was allowed to cause delays in well completions. We request comment on whether sufficient supply of this equipment and personnel to operate it will be available to accommodate the increased number of REC by the effective date of the NSPS. We also request specific estimates of how much time would be required to get enough equipment in operation to accommodate the full number of REC performed annually.

In the event that public comments indicate that available equipment would likely be insufficient to accommodate the increase in number of REC performed, we are considering phasing in requirements for well completions that would achieve an overall comparable level of environmental benefit. For example, operators performing completions of fractured or refractured existing wells (*i.e.,* modified wells) could be allowed to control emissions through pit flaring instead of REC for some period of time. After some date certain, all modified wells would be subject to REC. We solicit comment on the phasing of requirements for REC along with suggestions for other ways to address a potential short-term REC equipment shortage that may hinder operators' compliance with the proposed NSPS, while also achieving a comparable level of reduced emissions to the air.

Although we have determined that, on average, reduced emission completions are cost effective, well and reservoir characteristics could vary, such that some REC are more cost effective than others. Unlike most stationary source controls, REC equipment is used only for a 3 to 10 day period. Our review found that most operators contract with service companies to perform REC rather than purchase the equipment themselves, which was reflected in our economic analysis. It is also possible that the contracting costs of supplying and operating REC equipment may rise in the short term with the increased demand for those services. We request comment and any available technical information to judge whether our assumption of $33,237 per well completion for this service given the projected number of wells in 2015 subject to this requirement is accurate.

We believe that the proposed rule regulates only significant emission sources for which controls are cost-effective. Nevertheless, we solicit comment and supporting data on appropriate thresholds (*e.g.,* pressure, flowrate) that we should consider in specifying which well completions are subject to the REC requirements for subcategory 1 wells. Comments specifying thresholds should include an analysis of why sources below these thresholds are not cost effective to control.

In addition, there may be economic, technical or other opportunities or barriers associated with performing cost effective REC that we have not identified in our review. For example, some small regulated entities may have an increased source of revenue due to the captured product. On the other hand, some small regulated entities may have less access to REC than larger regulated entities might have. We request information on such opportunities and barriers that we should consider and suggestions for how we may take them into account in structuring the NSPS.

The second subcategory of fractured gas wells includes exploratory wells or delineation wells. Because these types of wells generally are not in proximity to existing gathering lines, REC is not an option, since there is no infrastructure in place to get the recovered gas to market or further processing. For these wells, the only potential control option we were able to identify is pit flaring, described above. As explained above, because of the slug flow nature of the flowback gas, water and sand, control by a traditional flare control device or other control devices, such as vapor recovery units, is infeasible, which leaves pit flaring as the only practicable control system for subcategory 2 wells. As also discussed above, open pit flaring can present a fire hazard or other undesirable impacts in some situations. Aside from the potential hazards associated with pit flaring, in some cases, we did not identify any nonair environmental impacts, health or energy impacts associated with pit flaring. However, pit flaring would produce NO_X emissions. As in the case of category 1 wells, we believe that these emissions cannot be controlled or measured directly due to the open combustion process characteristic of pit flaring. We again used published emission factors to estimate the NO_X emissions for purposes of assessing secondary impacts. For category 2 well completions, we estimated that 0.32 tons of NO_X are produced as secondary emissions per completion event. This is based on the assumption that 95 percent of flowback gas is combusted by the combustion device. The 22 tons of VOC reduced during the pit flaring used to control category 2 well completions is approximately 69 times greater than the NO_X produced. Thus, we believe that the benefit of the VOC reduction far outweighs the secondary impact of NO_X formation during pit flaring.

In light of the above, we propose to determine that BSER for subcategory 2 wells would be pit flaring. As we explained above, it is not practicable to measure the emissions during pit flaring or venting because the gas is discharged during flowback mixed with water and sand in multiphase slug flow. It is, therefore, not feasible to set a numerical performance standard.

Pursuant to CAA section 111(h)(2), we are proposing an operational standard for subcategory 2 wells that requires minimization of venting of gas and hydrocarbon vapors during the completion operation through the use of pit flaring, with provisions for venting in lieu of pit flaring for situations in which flaring would present safety hazards or for periods when the flowback gas is noncombustible due to high concentrations of nitrogen or carbon dioxide.

Consistent with requirements for subcategory 1 wells, owners or operators of subcategory 2 wells would be required to document completions and provide justification for periods when gas was vented in lieu of combustion. We solicit comment on whether there are other such situations where flaring would be unsafe or infeasible and potential criteria that would support venting in lieu of pit flaring.

For controlling completion emissions at oil wells and conventional (non-fractured) gas wells, we have identified and evaluated the following control options: REC in conjunction with pit flaring and pit flaring alone. Due to the low uncontrolled VOC emissions of approximately 0.007 ton per completion and, therefore, low potential emission reductions from these events, the cost per ton of reduction based on REC would be extremely high (over $700,000 per ton of VOC reduced). We evaluated the use of pit flaring alone as a system for controlling emissions from oil wells and conventional gas wells and determined that the cost cost-effectiveness would be approximately $520,000 per ton for oil wells and approximately $32,000 per ton for conventional gas wells. In light of the high cost per ton of VOC reduction, we do not consider either of these control options to be BSER for oil wells and conventional wells.

We propose that fracturing (or refracturing) and completion of an existing well (*i.e.,* a well existing prior to August 23, 2011) is considered a modification under CAA section 111(a), because physical change occurs to the existing well, which includes the wellbore, casing and tubing, resulting in an emissions increase during the completion operation. The physical change, in this case, would be caused by the reperforation of the casing and tubing, along with the refracturing of the wellbore. The increased VOC emissions would occur during the flowback period following the fracturing or refracturing operation. Therefore, the proposed standards for category 1 and category 2 wells would apply to completions at existing fractured or refractured wells.

EPA seeks comment on the 10 percent per year rate of refracturing for natural gas wells assumed in the impacts analysis found in the TSD. EPA has received anecdotal information suggesting that refracturing could be occurring much less frequently, while others suggest that the percent of wells refractured in a given year could be greater. We seek comment and comprehensive data and information on the rate of refracturing and key factors that influence or determine refracturing frequency.

In addition to well completions, we considered VOC emissions occurring at the wellhead affected facility during subsequent day-to-day operations during well production. As discussed below in section VI.B.1.e, VOC emissions from wellheads are very small during production and account for about 2.6 tons VOC per year. We are not aware of any cost effective controls that can be used to address these relatively small emissions.

b. NSPS for Pneumatic Controllers

Pneumatic controllers are automated instruments used for maintaining a process condition, such as liquid level, pressure, pressure differential and temperature. Pneumatic controllers are widely used in the oil and natural gas sector. In many situations across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate. In these ''gas-driven'' pneumatic controllers, natural gas may be released with every valve movement or continuously from the valve control pilot. The rate at which this release occurs is referred to as the device bleed rate. Bleed rates are dependent on the design of the device. Similar designs will have similar steady-state rates when operated under similar conditions. Gas-driven pneumatic controllers are typically characterized as ''high-bleed'' or ''low-bleed,'' where a high-bleed device releases more than 6 standard cubic feet per hour (scfh) of gas, with 18 scfh bleed rate being what we used in our analyses below. There are three basic designs: (1) Continuous bleed devices (high or low-bleed) are used to modulate flow, liquid level or pressure and gas is vented at a steady-state rate; (2) actuating/intermittent devices (high or low-bleed) perform quick control movements and only release gas when they open or close a valve or as they throttle the gas flow; and (3) self-contained devices release gas to a downstream pipeline instead of to the atmosphere. We are not aware of any add-on controls that are or can be used to reduce VOC emissions from gas-driven pneumatic devices.

For an average high-bleed pneumatic controller located in production (where the content of VOC in the raw product stream is relatively high), the difference in VOC emissions between a high-bleed controller and a low-bleed controller is around 1.8 tpy. For the transmission and storage segment (where the content of VOC in the pipeline quality gas is relatively low), the difference in VOC emissions between a high-bleed controller and a low-bleed controller is around 0.89 tpy. We have developed projections that estimate that approximately 13,600 new gas-driven units in the production segment and 67 new gas-driven units in the transmission and storage segment will be installed each year, including replacement of old units. Not all pneumatic controllers are gas driven. These ''non-gas driven'' pneumatic controllers use sources of power other than pressurized natural gas, such as compressed ''instrument air.'' Because these devices are not gas driven, they do not release natural gas or VOC emissions, but they do have energy impacts because electrical power is required to drive the instrument air compressor system. Electrical service of at least 13.3 kilowatts (kW) is required to power a 10 horsepower (hp) instrument air compressor, which is a relatively small capacity compressor. At sites without available electrical service sufficient to power an instrument air compressor, only gas driven pneumatic devices can be used. During our review, we determined that gas processing plants are the only facilities in the oil and natural gas sector highly likely to have electrical service sufficient to power an instrument air system, and that approximately half of existing gas processing plants are using non-gas driven devices.

For devices at gas processing plants, we evaluated the use of non-gas driven controllers and low-bleed controllers as options for reducing VOC emissions, with high-bleed controllers being the baseline. As mentioned above, non-gas driven devices themselves have zero emissions, but they do have energy impacts because electrical power is required to drive the instrument air compressor system. In our cost analysis, we determined that the annualized cost of installing and operating a fully redundant 10 hp (13.3 kW) instrument air system (systems generally are designed with redundancy to allow for system maintenance and failure without loss of air pressure), including duplicate compressors, air tanks and dryers, would be $11,090. A system of this size is capable of serving 15 control loops and reducing VOC emissions by 4.2 tpy, for a cost effectiveness of $2,659 per ton of VOC reduced. If the savings of the salable natural gas that would have been emitted is considered, the value of the gas not emitted would help offset the cost for this control, bringing the cost per ton of VOC down to $1,824.

We also evaluated the use of low-bleed controllers in place of high-bleed controllers at processing plants. We evaluated the impact of bleeding 6 standard cubic feet of natural gas per hour, which is the maximum bleed rate from low-bleed controllers, according to manufacturers of these devices. We chose natural gas as a surrogate for VOC, because manufacturers' technical specifications for pneumatic controllers are stated in terms of natural gas bleed rate rather than VOC. The capital cost difference between a new high-bleed controller and a new low-bleed controller is estimated to be $165. Without taking into account the savings due to the natural gas losses avoided, the annual costs are estimated to be around $23 per year, which is a cost of $13 per ton of VOC reduced for the production segment. If the savings of the salable natural gas that would have been emitted is considered, there is a net savings of $1,519 per ton of VOC reduced.

Although the non-gas-driven controller system is more expensive than the low-bleed controller system, it is still reasonably cost-effective. Furthermore, the non-gas-driven controller system achieves a 100-percent VOC reduction in contrast to a 66-percent reduction achieved by a low-bleed controller. Moreover, we believe the collateral emissions from electrical power generation needed to run the compressor are very low. Finally, non-gas-driven pneumatic controllers avoid potentially explosive concentrations of natural gas which can occur as a result of normal bleeding from groups of gas-driven pneumatic controllers located in close proximity, as they often are at gas processing plants. Based on our review described above, we believe that a non-gas-driven controller is BSER for reducing VOC emissions from pneumatic devices at gas processing plants. Accordingly, the proposed standard for pneumatic devices at gas processing plants is a zero VOC emission limit.

For the production (other than processing plants) and transmission and storage segments, where electrical service sufficient to power an instrument air system is likely unavailable and, therefore, only gas-driven devices can be used, we evaluated the use of low-bleed controllers in place of high-bleed controllers. Just as in our analysis of low-bleed controllers as an option for gas processing plants, we evaluated the impact of bleeding 6 standard cubic feet per minute (scfm) of natural gas per hour contrasted with 18 scfm from a high-bleed unit. Again, the capital cost difference between a new high-bleed controller and a new low-bleed controller is estimated to be $165. Without taking into account the savings due to the natural gas losses avoided, the annual costs are estimated to be around $23 per year, which is a cost of $13 per ton of VOC reduced for the production segment. If the savings of the salable natural gas that would have been emitted is considered, there is a net savings for this control. In the transmission and storage segment, where the VOC content of the vented gas is much lower than in the production segment, the cost effectiveness of a low-bleed pneumatic device is estimated to be around $262 per ton of VOC reduced. However, there are no potential offsetting savings to be realized in the transmission and storage segment, since the operators of transmission and storage stations typically do not own the gas they are handling. Based on our evaluation of the emissions and costs, we believe that low-bleed controllers represent BSER for pneumatic controllers in the production (other than processing plants) and transmission and storage segments. Therefore, for pneumatic devices at these locations, we propose a natural gas bleed rate limit of 6.0 scfh to reflect the VOC limit with the use of a low-bleed controller.

There may be situations where high-bleed controllers and the attendant gas bleed rate greater than 6 cubic feet per hour, are necessary due to functional requirements, such as positive actuation or rapid actuation. An example would be controllers used on large emergency shutdown valves on pipelines entering or exiting compression stations. For such situations, we have provided in the proposed rule an exemption where pneumatic controllers meeting the emission standards discussed above would pose a functional limitation due to their actuation response time or other operating characteristics. We are requesting comments on whether there are other situations that should be considered for this exemption. If you provide such comment, please specify the criteria for such situations that would help assure that only appropriate exemptions are claimed.

The proposed standards would apply to installation of a new pneumatic device (including replacing an existing device with a new device). We consider that a pneumatic device, an apparatus, is an affected facility and each installation is construction subject to the proposed NSPS. See definitions of ''affected facility'' and ''construction'' at 40 CFR 60.2.

c. NSPS for Compressors

There are many locations throughout the oil and natural gas sector where compression of natural gas is required to move it along the pipeline. This is accomplished by compressors powered by combustion turbines, reciprocating internal combustion engines or electric motors. Turbine-powered compressors use a small portion of the natural gas that they compress to fuel the turbine. The turbine operates a centrifugal compressor, which compresses the natural gas for transit through the pipeline. Sometimes an electric motor is used to turn a centrifugal compressor. This type of compressor does not require the use of any of the natural gas from the pipeline, but it does require a substantial source of electricity. Reciprocating spark ignition engines are also used to power many compressors, referred to as reciprocating compressors, since they compress gas using pistons that are driven by the engine. Like combustion turbines, these engines are fueled by natural gas from the pipeline. Both centrifugal and reciprocating compressors are sources of VOC emissions and were evaluated for coverage under the NSPS.

Centrifugal Compressors. Centrifugal compressors require seals around the rotating shaft to minimize gas leakage and fugitive VOC emissions from where the shaft exits the compressor casing. There are two types of seal systems: Wet seal systems and mechanical dry seal systems.

Wet seal systems use oil, which is circulated under high pressure between three or more rings around the compressor shaft, forming a barrier to minimize compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. The amount of gas absorbed and entrained by the oil barrier is affected by the operating pressure of the gas being handled; higher operating pressures result in higher absorption of gas into the oil. Seal oil is purged of the absorbed and entrained gas (using heaters, flash tanks and degassing techniques) and recirculated to the seal area for reuse. Gas that is purged from the seal oil is commonly vented to the atmosphere. Degassing of the seal oil emits an average of 47.7 scfm of gas, depending on the operating pressure of the compressor. An uncontrolled wet seal system can emit, on average, approximately 20.5 tpy of VOC during the venting process (production segment) or about 3.5 tpy (transmission and storage segment). We identified two potential control techniques for reducing emissions from degassing of wet seal systems: (1) Routing the gas back to a low pressure fuel stream to be combusted as fuel gas and (2) routing the gas to a flare. We know only of anecdotal, undocumented information on routing of the gas back to a fuel stream and, therefore, were unable to assess costs and cost effectiveness of the first option. Although we do not have specific examples of routing emissions from wet seal degassing to a flare, we were able to estimate the cost, emission reductions and cost effectiveness of the second option using uncontrolled wet seals as a baseline.

Based on the average uncontrolled emissions of wet seal systems discussed above and a flare efficiency of 95 percent, we determined that VOC emission reductions from a wet seal system would be an average of 19.5 tpy (production segment) or 3.3 tpy (transmission and storage segment). Using an annualized cost of flare installation and operation of $103,373, we estimated the incremental cost effectiveness of this option (from uncontrolled wet seals to controlled wet seals using a flare) to be approximately $5,300/ton and $31,000/ton for the production segment and transmission and storage segment, respectively. With this option, there would be secondary air impacts from combustion. However we did not identify any nonair quality or energy impacts associated with this control technique.

Dry seal systems do not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. Fugitive emissions occur from dry seals around the compressor shaft. Based on manufacturer studies and engineering design estimates, fugitive emissions from dry seal systems are approximately 6 scfm of gas, depending on the operating pressure of the compressor. A dry seal system can have fugitive emissions of, on average, approximately 2.6 tpy of VOC (production segment) or about 0.4 tpy (transmission and storage segment). We did not identify any control device suitable to capture and control the fugitive emissions from dry seals around the compressor shaft.

Using uncontrolled wet seals as a baseline, we evaluated the reductions and incremental cost effectiveness of dry seal systems. Based on the average fugitive emissions, we determined that VOC emission reductions achieved by dry seal systems compared to uncontrolled wet seal systems would be 18 tpy (production segment) and 3.1 tpy (transmission and storage segment). Combined with an annualized cost of dry seal systems of $10,678, the incremental cost effectiveness compared to uncontrolled wet seal systems would be $595/ton and $3,495/ton for the production segment and transmission and storage segment, respectively. We identified neither nonair quality nor any energy impacts associated with this option.

In performing our analysis, we estimated the incremental cost of a dry seal compressor over that of an equivalent wet seal compressor to be $75,000. This value was obtained from a vendor who represents a large share of the market for centrifugal compressors. However, this number likely represents a conservatively high value because wet seal units have a significant amount of ancillary equipment, namely the seal oil system and, thus, additional capital expenses. Dry seal systems have some ancillary equipment (the seal gas filtration system), but the costs are less than the wet seal oil system. We were not able to directly confirm this assumption with the vendor, however, a search of product literature showed that seal oil systems and seal gas filtration systems are typically listed separate from the basic compressor package. Using available data on the cost of this equipment, it is very likely that the cost of purchasing a dry seal compressor may actually be lower that a wet seal compressor. We seek comment on available cost data of a dry seal versus wet seal compressor, including all ancillary equipment costs.

In light of the above analyses, we propose to determine that dry seal systems are BSER for reducing VOC emissions from centrifugal compressors. We evaluated the possibility of setting a performance standard that reflects the emission limitation achievable through the use of a dry seal system. However, as mentioned above, VOC from centrifugal compressors with dry seals are fugitive emissions from around the compressor shafts. There is no device to capture and control these fugitive emissions, nor can reliable measurement of these emissions be conducted due to difficulty in accessing the leakage area and danger of contacting the shaft rotating at approximately 30,000 revolutions per minute. This not only poses a likely hazard that would destroy test equipment on contact, it poses a safety hazard to personnel, as well. Therefore, pursuant to section 111(h)(2) of the CAA, we are proposing an equipment standard that would require the use of dry seals to limit the VOC emissions from new centrifugal compressors. We consider that a centrifugal compressor, an apparatus, is an affected facility and each installation is construction subject to the proposed NSPS. See definitions of ''affected facility'' and ''construction'' at 40 CFR 60.2. Accordingly, the proposed standard would apply to installation of new centrifugal compressors at new locations, as well as replacement of old compressors.

Although we are proposing to determine dry seal systems to be BSER for centrifugal compressors, we are soliciting comments on the emission reduction potential, cost and any limitations for the option of routing the gas back to a low pressure fuel stream to be combusted as fuel gas. In addition, we solicit comments on whether there are situations or applications where wet seal is the only option, because a dry seal system is infeasible or otherwise inappropriate.

Reciprocating Compressors. Reciprocating compressors in the natural gas industry leak natural gas fugitive VOC during normal operation. The highest volumes of gas loss and fugitive VOC emissions are associated with piston rod packing systems. Packing systems are used to maintain a tight seal around the piston rod, preventing the high pressure gas in the compressor cylinder from leaking, while allowing the rod to move freely. This leakage rate is dependent on a variety of factors, including physical size of the compressor piston rod, operating speed and operating pressure. Under the best conditions, new packing systems properly installed on a smooth, well-aligned shaft can be expected to leak a minimum of 11.5 scfh. Higher leak rates are a consequence of fit, alignment of the packing parts and wear.

We evaluated the possibility of reducing VOC emissions from reciprocal compressors through a control device. However, VOC from reciprocating compressors are fugitive emissions from around the compressor shafts. Although it is possible to construct an enclosure around the rod packing area and vent the emissions outside for safety purposes, connection to a closed vent system and control device would create back pressure on the leaking gas. This back pressure would cause the leaked gas instead to be forced inside the crankcase of the engine, which would dilute lubricating oil, causing premature failure of engine bearings, pose an explosion hazard and eventually be vented from the crankcase breather, defeating the purpose of a control device.

As mentioned above, as packing wears and deteriorates, leak rates can increase. We, therefore, evaluate replacement of compressor rod packing systems as an option for reducing VOC emissions. Conventional bronze-metallic packing rings wear out and need to be replaced every 3 to 5 years, depending on the compressor's rate of usage (*i.e.,* the percentage of time that a compressor is in pressurized mode).

Based on industry experience in the Natural Gas STAR program and other sources, we evaluated the rod packing replacement costs for reciprocating compressors at different segments of this industry. Usage rates vary by segment. Usage rates for compressors at wellheads, gathering/boosting stations, processing plants, transmission stations and storage facilities are 100, 79, 90, 79 and 68 percent, respectively. Reciprocating compressors at wellheads are small and operate at lower pressures, which limit VOC emissions from these sources. Due to the low VOC emissions from these compressors, about 0.044 tpy, combined with an annual cost of approximately $3,700, the cost per ton of VOC reduction is rather high. We estimated that the cost effectiveness of controlling wellhead compressors is over $84,000 per ton of VOC reduced, which we believe to be too high and, therefore, not reasonable. Because the cost effectiveness of replacing packing wellhead compressor rod systems is not reasonable, and absent other emission reduction measures, we did not find a BSER for reducing VOC emissions from reciprocal compressors at wellheads.

For reciprocating compressors located at other oil and gas operations, we estimated that the cost effectiveness of controlling compressor VOC emissions by rod packing replacement would be $870 per ton of VOC for reciprocating compressors at gathering and boosting stations, $270 per ton of VOC for reciprocating compressors at processing stations, $2,800 per ton of VOC for reciprocating compressors at transmission stations and $3,700 per ton of VOC for reciprocating compressors at underground storage facilities. We consider these costs to be reasonable. We did not identify any nonair quality health or environmental impacts or energy impacts associated with rod packing replacement. In light of the above, we propose to determine that such control is the BSER for reducing

VOC emission from compressors at these other oil and gas operations.

Because VOC emitted from reciprocal compressors are fugitive emissions, there is no device to capture and control the emissions. Therefore, pursuant to section 111(h) of the CAA, we are proposing an operational standard. Based on industry experience reported to the Natural Gas STAR program, we determined that packing rods should be replaced every 3 years of operation. However, to account for segments of the industry in which reciprocating compressors operate in pressurized mode a fraction of the calendar year (ranging from approximately 68 percent up to approximately 90 percent), the proposed rule expresses the replacement requirement in terms of hours of operation rather than on a calendar year basis. One year of continuous operation would be 8,760 hours. Three years of continuous operation would be 26,280 hours, or rounded to the nearest thousand, 26,000 hours. Accordingly, the proposed rule would require the replacement of the rod packing every 26,000 hours of operation. The owner or operator would be required to monitor the hours of operation beginning with the installation of the reciprocating compressor affected facility. Cumulative hours of operation would be reported each year in the facility's annual report. Once the hours of operation reached 26,000 hours, the owner or operator would be required to change the rod packing immediately, although unexpected shutdowns could be avoided by tracking hours of operation and planning for packing replacement at scheduled maintenance shutdowns before the hours of operation reached 26,000.

Some industry partners of the Natural Gas STAR program currently conduct periodic testing to determine the leakage rates that would identify economically beneficial replacement of rod packing based on natural gas savings. Therefore, we are soliciting comments on incorporating a method similar to that in the Natural Gas STAR's Lessons Learned document entitled, *Reducing Methane Emissions from Compressor Rod Packing Systems* (*http://www.epa.gov/gasstar/documents/ll_rodpack.pdf*), to be incorporated in the NSPS. We are soliciting comments on how to determine a suitable leak threshold above which rod packing replacement would be cost effective for VOC emission reduction. We are also soliciting comment on the appropriate replacement frequency and other considerations that would be associated with regular replacement periods.

d. NSPS for Storage Vessels

Crude oil, condensate and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically located as part of a tank battery. A tank battery refers to the collection of process equipment used to separate, treat and store crude oil, condensate, natural gas and produced water. The extracted products from productions wells enter the tank battery through the production header, which may collect product from many wells.

Emissions from storage vessels are a result of working, breathing and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with dissolved gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus, allowing dissolved gases and a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage stage. Temperature of the liquid also influences the amount of flash emissions. The amount of liquid entering the tank during a given time, commonly known as throughput, also affects the emission rate, with higher throughput tanks having higher annual emissions, given that other parameters are the same.

In analyzing controls for storage vessels, we reviewed control techniques identified in the Natural Gas STAR program and state regulations. We identified two ways of controlling storage vessel emissions, both of which can reduce VOC emissions by 95 percent. One option would be to install a vapor recovery unit (VRU) and recover all the vapors from the tanks. The other option would be to route the emissions from the tanks to a flare control device. These devices could be ''candlestick'' flares that are found at gas processing plants or other larger facilities or enclosed combustors which are commonly found at smaller field facilities. We estimated the total annual cost for a VRU to be approximately $18,900/yr and for a flare to be approximately $8,900/yr. Cost effectiveness of these control options depend on the amount of vapor produced by the storage vessels being controlled. A VRU has a potential advantage over flaring, in that it recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold. If natural gas is recovered, it can be sold, as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU also does not have secondary air impacts that flaring does, as described below. However, a VRU cannot be used in all instances. Some conditions that affect the feasibility of VRU are: Availability of electrical service sufficient to power the VRU; fluctuations in vapor loading caused by surges in throughput and flash emissions from the tank; potential for drawing air into condensate tanks causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

Like a VRU, a flare control device can also achieve a control efficiency of 95 percent. There are no technical limitations on the use of flares to control vapors from condensate and crude oil tanks. However, flaring has a secondary impact from emissions of NO_X and other pollutants. In light of the technical limitations with the use of a VRU, we are unable to conclude that a VRU is better than flaring. We, therefore, propose to determine that both a VRU and flare are BSER for reducing VOC emission from storage vessels. We propose an NSPS of 95-percent reduction for storage vessels to reflect the level of emission reduction achievable by VRU and flares.

VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (*i.e.,* its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility and temperature of the liquid. Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric pressure. We do not believe that it is cost effective to control these vessels. We believe it is important to control tanks with significant VOC emissions under the proposed NSPS.

In our analysis, we evaluated storage tanks with varying condensate or crude oil throughput. We used emission factors developed for the Texas Environmental Research Consortium in a study that evaluated VOC emissions from crude oil and condensate storage tanks by performing direct measurements. The study found that the average VOC emission factor for crude oil storage tanks was 1.6 pounds (lb) VOC per barrel of crude oil throughput. The average VOC emission factor for condensate tanks was determined to be 33.3 lb VOC per barrel of condensate throughput. Applying these emission factors and evaluating condensate throughput rates of 0.5, 1, 2 and 5 barrels per day (bpd), we determined that VOC emissions at these condensate throughput rates would be approximately 3, 6, 12 and 30 tpy, respectively. Similarly, we evaluated crude oil throughput rates of 1, 5, 20 and 50 bpd. Based on the Texas study, these crude oil throughput rates would result in VOC emissions of 0.3, 1.5, 5.8 and 14.6 tpy, respectively. We believe that it is important to control tanks with significant VOC emissions. Furthermore, we believe it would be easier and less costly for owners and operators to determine applicability by using a throughput threshold instead of an emissions threshold. As a result of the above analyses, we believe that storage vessels with at least 1 bpd of condensate or 20 bpd of crude oil should be controlled. These throughput rates are equivalent to VOC emissions of approximately 6 tpy. Based on an estimated annual cost of $18,900 for the control device, controlling storage vessels with these condensate or crude oil throughputs would result in a cost effectiveness of $3,150 per ton of VOC reduced.

Based on our evaluation, we propose to determine that both a VRU and flare are BSER for reducing VOC emission from storage vessels with throughput of at least 1 barrel of condensate per day or 20 barrels of crude oil per day. We propose an NSPS of 95-percent reduction for these storage vessels to reflect the level of emission reduction achievable by VRU and flare control devices.

For storage vessels below the throughput levels described above (''small throughput tanks''), for which we do not consider flares or VRU to be cost effective controls, we evaluated other measures to reduce VOC emissions. Standard practices for such tanks include requiring a cover that is well designed, maintained in good condition and kept closed. Crude oil and condensate storage tanks in the oil and natural gas sector are designed to operate at or just slightly above or below atmospheric pressure. Accordingly, they are provided with vents to prevent tank destruction under rapid pressure increases due to flash emissions conditions. Studies by the Natural Gas STAR program and by others have shown that working losses (*i.e.,* those emissions absent flash emission conditions) are very low, approaching zero. During times of flash emissions, tanks are designed such that the flash emissions are released through a vent on the fixed roof of the tank when pressure reaches just a few ounces to prevent pressure buildup and resulting tank damage. At those times, vapor readily escapes through the vent to protect the tank. Tests have shown that open hatches or leaking hatch gaskets have little effect on emissions from uncontrolled tanks due to the functioning roof vent. However, in the case of controlled tanks, the control requirements include provisions for maintaining integrity of the closed vent system that conveys emissions to the control device, including hatches and other tank openings. As a result, hatches are required to be kept closed and gaskets kept in good repair to meet control requirements of controlled storage vessels. Because the measures we evaluated, including maintenance of hatch integrity, do not provide appreciable emission reductions for storage vessels with throughputs under 1 barrel of condensate per day and 21 barrels of crude oil per day, we believe that the control options we evaluated do not reflect BSER for the small throughput tanks and we are not proposing standards for these tanks.

As discussed in section VII of this preamble, we are proposing to amend the NESHAP for oil and natural gas production facilities at 40 CFR part 63, subpart HH to require that all storage vessels at production facilities reduce HAP emissions by 95 percent. Because the controls used to achieve the 95-percent HAP reduction are the same as the proposed BSER for VOC reduction for storage vessels (*i.e.,* VRU and flare), sources that are achieving the 95-percent HAP reduction would also be meeting the proposed NSPS of 95-percent VOC reduction. In light of the above, and to avoid duplicate monitoring, recordkeeping and reporting, we propose that storage vessels subject to the requirements of subpart HH are exempt from the proposed NSPS for storage vessel in 40 CFR part 60, subpart OOOO.

e. NSPS for VOC Equipment Leaks

Equipment leaks are fugitive emissions emanating from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines and other process and operation components. There are several potential reasons for equipment leak emissions. Components such as pumps, valves, pressure relief valves, flanges, agitators and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. Because of the large number of valves, pumps and other components within an oil and gas production, processing and transmission facility, equipment leak volatile emissions from these components can be significant. Natural gas processing plants, especially those using refrigerated absorption and transmission stations tend to have a large number of components. Equipment leaks from processing plants are addressed in our review of 40 CFR part 60, subpart KKK, which is discussed above in section VI.B.1.

In addition to gas processing plants, these types of equipment also exist at oil and gas production sites and gas transmission and storage facilities. While the number of components at individual transmission and storage facilities is relatively smaller than at processing plants, collectively, there are many components that can result in significant emissions.

Therefore, we evaluated applying NSPS for equipment leaks to facilities in the production segment of the industry, which includes everything from the wellhead to the point that the gas enters the processing plant, transmission pipeline or distribution pipeline. Production facilities can vary significantly in the operations performed and the processes, all of which impact the number of components and potential emissions from leaking equipment and, thus, impact the annual costs related to implementing a LDAR program. We used data collected by the Gas Research Institute to develop model production facilities. Baseline emissions, along with emission reductions and costs of regulatory alternatives, were estimated using these model production facilities. We considered production facilities where separation, storage, compression and other processes occur. These facilities may not have a wellhead on-site, but would be associated with a wellhead. We also evaluated gathering and boosting facilities, where gas and/or oil are collected from a number of wells, then processed and transported downstream to processing plants or transmission stations. We evaluated the impacts at these production facilities with varying number of operations and equipment. We also developed a model plant for the transmission and storage segment using data from the Gas

Research Institute. Details of these evaluations may be found in the TSD in the docket.

For an average production site at or associated with a wellhead, we estimated annual VOC emissions from equipment leaks of around 2.6 tpy. For an average gathering/boosting facility, we estimated the annual VOC emissions from equipment leaks to be around 9.8 tpy. The average transmission and storage facility emits 2.7 tpy of VOC.

For facilities in each non-gas processing plant segment, we evaluated the same four options as we did for gas processing plants in section VI.B.1 above. These four options are as follows: (1) 40 CFR part 60, subpart VVa-level LDAR (which is based on conducting Method 21 monthly, defining ''leak'' at 500 ppm threshold, and adding connectors to the VV list of components to be monitored); (2) monthly optical gas imaging with annual Method 21 check (the alternative work practice for monitoring equipment for leaks at 40 CFR 60.18(g)); (3) monthly optical gas imaging alone; and (4) annual optical gas imaging alone.

For option 1, we evaluated subpart VVa-LDAR as a whole. We also analyzed separately the individual types of components (valves, connectors, pressure relief devices and open-ended lines). Detailed discussions of these component by component analyses are included in the TSD in the docket.

Based on our evaluation, subpart VVa-level LDAR (Option 1) results in more VOC reduction than the subpart VV-level LDAR currently required for gas processing plants, because more leaks are found based on the lower definition of ''leak'' under subpart VVa (10,000 ppm for subpart VV and 500 ppm for subpart VVa). In addition, our evaluation shows that the cost per ton of VOC reduced for subpart VVa level controls is less than the cost per ton of VOC reduced for the less stringent subpart VV level of control. Although the cost of repairing more leaks is higher, the increased VOC control afforded by subpart VVa level controls more than offsets the increased costs.

For the subpart VVa level of control at the average production site associated with a wellhead, average facility-wide cost-effectiveness would be $16,084 per ton of VOC. Component-specific cost-effectiveness ranged from $15,063 per ton of VOC (for valves) to $211,992 per ton of VOC (for pressure relief devices), with connectors and open-ended lines being $74,283 and $180,537 per ton of VOC, respectively. We also looked at component costs for a modified subpart VVa level of control with less frequent monitoring for valves and connectors at production sites associated with a wellhead.[12] The cost-effectiveness for valves was calculated to be $17,828 per ton of VOC by reducing the monitoring frequency from monthly to annually. The cost-effectiveness for connectors was calculated to be $87,277 per ton of VOC by reducing the monitoring frequency from every 4 years to every 8 years after the initial compliance period.

We performed a similar facility-wide and component-specific analysis of option 1 LDAR for gathering and boosting stations. For the subpart VVa level of control at the average gathering and boosting station, facility-wide cost-effectiveness was estimated to be $9,344 per ton of VOC. Component-specific cost-effectiveness ranged from $6,079 per ton of VOC (for valves) to $77,310 per ton of VOC (for open-ended lines), with connectors and pressure relief devices being $23,603 and $72,523 per ton, respectively. For the modified subpart VVa level of control at gathering and boosting stations, cost-effectiveness ranged from $5,221 per ton of VOC (for valves) to $77,310 per ton of VOC (for open-ended lines), with connectors and pressure relief devices being $27,274 and $72,523 per ton, respectively. The modified subpart VVa level controls were more cost-effective than the subpart VVa level controls for valves, but not for connectors. This is due to the low cost of monitoring connectors and the low VOC emissions from leaking connectors.

We also performed a similar analysis of option 1 subpart VVa-level LDAR for gas transmission and storage facilities. For the subpart VVa level of control at the average transmission and storage facility, facility-wide cost-effectiveness was $20,215. Component-specific cost-effectiveness ranged from $24,762 per ton of VOC (for open-ended lines) to $243,525 per ton of VOC (for pressure relief devices), with connectors and valves being $36,527 and $43,111 per ton of VOC, respectively. For the modified subpart VVa level of control at transmission and storage facilities, cost-effectiveness ranged from $24,762 per ton of VOC (for open-ended lines) to $243,525 per ton of VOC (for pressure relief devices), with connectors and valves being $42,140 and $40,593 per ton of VOC, respectively. Again, the modified subpart VVa level controls were more cost-effective for valves and less cost effective for connectors than the subpart VVa level controls. This is due to the low cost of monitoring connectors and the low VOC emissions from leaking connectors.

For each of the non-gas processing segments, we also evaluated monthly optical gas imaging with annual Method 21 check (Option 2). As discussed in secton VI.B.1, we had previously determined that the VOC reductions achieved under this option would be the same as for option 1 subpart VVa-level LDAR. In our evaluation of Option 2, we estimated that a single optical imaging instrument could be used for 160 well sites and 13 gathering and boosting stations, which means that the cost of the purchase or rental of the camera would be spread across 173 facilities.

For production sites, gathering and boosting stations, and transmission and storage facilities, we estimated that option 2 monthly optical gas imaging with annual Method 21 check would have cost-effectiveness of $16,123, $10,095, and $19,715 per ton of VOC, respectively.[13]

The annual costs for option 1 and option 2 leak detection and repair programs for production sites associated with a wellhead, gathering and boosting stations and transmission and storage facilities were higher than those estimated for natural gas processing plants because natural gas processing plant annual costs are based on the incremental cost of implementing subpart VVa-level standards, whereas the other facilities are not currently regulated under an LDAR program. The currently unregulated sites would be required to set up a new LDAR program; perform initial monitoring, tagging, logging and repairing of components; as well as planning and training personnel to implement the new LDAR program.

In addition to options 1 and 2, we evaluated a third option that consisted of monthly optical gas imaging without an annual Method 21 check. Because we were unable to estimate the VOC emissions achieved by an optical imaging program alone, we were unable to estimate the cost-effectiveness of this option. However, we estimated the annual cost of the monthly optical gas imaging LDAR program at production sites, gathering and boosting stations, and transmission and storage facilities to be $37,049, $86,135, and $45,080, respectively, based on camera purchase, or $32,693, $81,780, and $40,629, respectively, based on camera rental.

Finally, we evaluated a fourth option similar to the third option except that the optical gas imaging would be performed annually rather than monthly. For this option, we estimated the annual cost for production sites, gathering and boosting stations, and transmission and storage facilities to be

[13] Because optical gas imaging is used to view several pieces of equipment at a facility at once to survey for leaks, options involving imaging are not amenable to a component by component analysis.

$30,740, $64,416, and $24,031, respectively, based on camera purchase, or $26,341, $60,017, and $19,493, respectively, based on camera rental.

We request comment on the applicability of a leak detection and repair program based solely on the use of optical imaging or other technologies. Of most use to us would be information on the effectiveness of advanced measurement technologies to detect and repair small leaks on the same order or smaller as specified in the VVa equipment leak requirements and the effects of increased frequency of and associated leak detection, recording, and repair practices.

Based on the evaluation described above, we believe that neither option 1 nor option 2 is cost effective for reducing fugitive VOC emissions from equipment leaks at sites, gathering and boosting stations, and transmission and storage facilities. For options 3 and 4, we were unable to estimate their cost effectiveness and, therefore, could not identify either of these two options as BSER for addressing equipment leak of VOC at production facilities associated with wellheads, at gathering and boosting stations or at gas transmission and storage facilities. We are, therefore, not proposing NSPS for addressing VOC emissions from equipment leaks at these facilities.

5. What are the SSM provisions?

The EPA is proposing standards in this rule that apply at all times, including during periods of startup or shutdown, and periods of malfunction. In proposing the standards in this rule, the EPA has taken into account startup and shutdown periods.

The General Provisions in 40 CFR part 60 require facilities to keep records of the occurrence and duration of any startup, shutdown or malfunction (40 CFR 60.7(b)) and either report to the EPA any period of excess emissions that occurs during periods of SSM (40 CFR 60.7(c)(2)) or report that no excess emissions occurred (40 CFR 60.7(c)(4)). Thus, any comments that contend that sources cannot meet the proposed standard during startup and shutdown periods should provide data and other specifics supporting their claim.

Periods of startup, normal operations and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a ''sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *'' (40 CFR 60.2.) The EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 111 standards. Further, nothing in CAA section 111 or in case law requires that the EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. See, *Weyerhaeuser* v *Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978) (''In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.''), and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 111 standards.

Further, it is reasonable to interpret CAA section 111 as not requiring the EPA to account for malfunctions in setting emissions standards. For example, we note that CAA section 111 provides that the EPA set standards of performance which reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. Applying the concept of ''the application of the best system of emission reduction'' to periods during which a source is malfunctioning presents difficulties. The ''application of the best system of emission reduction'' is more appropriately understood to include operating units in such a way as to avoid malfunctions.

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 111 standards for affected facilities under 40 CFR part 60, subpart OOOO. As noted above, by definition, malfunctions are sudden and unexpected events and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in the category. Moreover, malfunctions can vary in frequency, degree and duration, further complicating standard setting.

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, ''sudden, infrequent, not reasonably preventable'' and was not instead ''caused in part by poor maintenance or careless operation.'' 40 CFR 60.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail. Such failure can sometimes cause an exceedance of the relevant emission standard (See, *e.g.,* State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (September 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (February 15, 1983)). The EPA is, therefore, proposing to add an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. See 40 CFR 60.41Da (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also are proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 60.46Da. (See 40 CFR 22.24). These criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 60.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions ''[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *'' The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 60.40Da and to prevent future malfunctions. For example, the source would have to prove by a preponderance of the evidence that ''[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *'' and that ''[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *'' In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met the burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113 (see also 40 CFR part 22.77).

VII. Rationale for Proposed Action for NESHAP

A. What data were used for the NESHAP analyses?

To perform the technology review and residual risk analysis for the two NESHAP, we created a comprehensive dataset (*i.e.,* the MACT dataset). This dataset was based on the EPA's 2005 National Emissions Inventory (NEI). The NEI database contains information about sources that emit criteria air pollutants and their precursors and HAP. The database includes estimates of annual air pollutant emissions from point, nonpoint and mobile sources in the 50 states, the District of Columbia, Puerto Rico and the Virgin Islands. The EPA collects information about sources and releases an updated version of the NEI database every 3 years.

The NEI database is compiled from these primary sources:

- Emissions inventories compiled by state and local environmental agencies
- Databases related to the EPA's MACT programs
- Toxics Release Inventory data
- For electric generating units, the EPA's Emission Tracking System/ CEM data and United States Department of Energy (DOE) fuel use data
- For onroad sources, the United States Federal Highway Administration's estimate of vehicle miles traveled and emission factors from the EPA's MOBILE computer model
- For nonroad sources, the EPA's NONROAD computer model
- Emissions inventories from previous years, if states do not submit current data

To concentrate on only records pertaining to the oil and natural gas industry sector, data were extracted using two criteria. First, we specified that all facilities containing codes identifying the Oil and Natural Gas Production and the Natural Gas Transmission and Storage MACT source categories (MACT codes 0501 and 0504, respectively). Second, we extracted facilities identified with the following NAICS codes: 211 * * * (Oil and Gas Extraction), 221210 (Natural Gas Distribution), 4861 * * * (Pipeline Transportation of Crude Oil), and 4862 * * * (Pipeline Transportation of Natural Gas). Once the data were extracted, we reviewed the Source Classification Codes (SCC) to assess whether there were any records included in the dataset that were clearly not a part of the oil and natural gas sector. Our review of the SCC also included assigning each SCC to an ''Emission Process Group'' that represents emission point types within the oil and natural gas sector.

Since these MACT standards only apply to major sources, only facilities designated as major sources in the NEI were extracted. In the NEI, sources are identified as major if the facility-wide emissions are greater than 10 tpy for any single HAP or 25 tpy for any combination of HAP. We believe that this may overestimate the number of major sources in the oil and natural gas sector because it does not take into account the limitations set forth in the CAA regarding aggregation of emissions from wells and associated equipment in determining major source status.

The final dataset contained a total of 1,311 major sources in the oil and natural gas sector; 990 in Oil and Natural Gas Production, and 321 in Natural Gas Transmission and Storage. To assess how representative this number of facilities was, we obtained information on the number of subject facilities for both MACT standards from the Enforcement and Compliance History Online (ECHO) database. The ECHO database is a web-based tool (*http://www.epa-echo.gov/echo/index.html*) that provides public access to compliance and enforcement information for approximately 800,000 EPA-regulated facilities. The ECHO database allows users to find permit, inspection, violation, enforcement action and penalty information covering the past 3 years. The site includes facilities regulated as CAA stationary sources, as well as Clean Water Act direct dischargers, and Resource Conservation and Recovery Act hazardous waste generators/handlers. The data in the ECHO database are updated monthly.

We performed a query on the ECHO database requesting records for major sources, with NAICS codes 211*, 221210, 4861* and 4862*, with information for MACT. The ECHO database query identified records for a total of 555 facilities, 269 in the Oil and Natural Gas Production source category (NAICS 211* and 221210) and 286 in the Natural Gas Transmission and Storage source category (NAICS 4861* and 4862*). This comparison leads us to conclude that, for the Natural Gas Transmission and Storage segment, the NEI database is representative of the number of sources subject to the rule. For the Oil and Natural Gas Production source category, it confirms our assumption that the NEI dataset contains more facilities than are subject to the rule. However, this provides a conservative overestimate of the number of sources, which we believe is appropriate for our risk analyses.

We are requesting that the public provide a detailed review of the information in this dataset and provide comments and updated information where appropriate. Section X of this preamble provides an explanation of how to provide updated information for these datasets.

B. What are the proposed decisions regarding certain unregulated emissions sources?

In addition to actions relative to the technology review and risk reviews discussed below, we are proposing, pursuant to CAA sections 112(d)(2) and (3), MACT standards for glycol dehydrators and storage vessels for which standards were not previously developed. We are also proposing changes that affect the definition of ''associated equipment'' which could apply these MACT standards to previously unregulated sources.

1. Glycol Dehydrators

Once natural gas has been separated from any liquid materials or products (*e.g.,* crude oil, condensate or produced water), residual entrained water is removed from the natural gas by dehydration. Dehydration is necessary because water vapor may form hydrates, which are ice-like structures, and can cause corrosion in or plug equipment lines. The most widely used natural gas dehydration processes are glycol dehydration and solid desiccant dehydration. Solid desiccant dehydration, which is typically only used for lower throughputs, uses adsorption to remove water and is not a source of HAP emissions.

Glycol dehydration is an absorption process in which a liquid absorbent, glycol, directly contacts the natural gas stream and absorbs any entrained water vapor in a contact tower or absorption column. The majority of glycol dehydration units use triethylene glycol as the absorbent, but ethylene glycol and diethylene glycol are also used. The rich glycol, which has absorbed water vapor from the natural gas stream, leaves the bottom of the absorption column and is directed either to (1) a gas condensate glycol (GCG) separator (flash tank) and then a reboiler or (2) directly to a reboiler where the water is boiled off of the rich glycol. The regenerated glycol (lean glycol) is circulated, by pump, into the absorption tower. The vapor generated in the reboiler is directed to the reboiler vent.

The reboiler vent is a source of HAP emissions. In the glycol contact tower, glycol not only absorbs water, but also absorbs selected hydrocarbons, including BTEX and n-hexane. The hydrocarbons are boiled off along with the water in the reboiler and vented to the atmosphere or to a control device. The most commonly used control device is a condenser. Condensers not only reduce emissions, but also recover condensable hydrocarbon vapors that can be recovered and sold. In addition, the dry non-condensable off-gas from the condenser may be used as fuel or recycled into the production process or directed to a flare, incinerator or other combustion device.

If present, the GCG separator (flash tank) is also a potential source of HAP emissions. Some glycol dehydration units use flash tanks prior to the reboiler to separate entrained gases, primarily methane and ethane from the glycol. The flash tank off-gases are typically recovered as fuel or recycled to the natural gas production header. However, the flash tank may also be vented directly to the atmosphere. Flash tanks typically enhance the reboiler condenser's emission reduction efficiency by reducing the concentration of non-condensable gases present in the stream prior to being introduced into the condenser.

In the development of the MACT standards for the two oil and natural gas source categories, the EPA created two subcategories of glycol dehydrators based on actual annual average natural gas flowrate and actual average benzene emissions. Under 40 CFR part 63, subpart HH, (the Oil and Natural Gas Production NESHAP), the EPA established MACT standards for glycol dehydration units with an actual annual average natural gas flowrate greater than or equal to 85,000 scmd and actual average benzene emissions greater than or equal to 0.90 Mg/yr (40 CFR 63.765(a)). The EPA did not establish standards for the other subcategory, which consists of glycol dehydration units that are below the flowrate and emission thresholds specified in subpart HH. Similarly, under 40 CFR part 63, subpart HHH (the Natural Gas Transmission and Storage NESHAP), the EPA established MACT standards for the subcategory of glycol dehydration units with an actual annual average natural gas flowrate greater than or equal to 283,000 scmd and actual average benzene emissions greater than or equal to 0.90 Mg/yr, but did not establish standards for the other subcategory, which consists of glycol dehydration units that are below the flowrate and emission thresholds specified in subpart HHH. As mentioned above, we refer to these unregulated dehydration units in both subparts HH and HHH as ''small dehydrators'' in this proposed rule.

The EPA is proposing emission standards for these subcategories of small dehydrators (*i.e.,* those dehydrators with an actual annual average natural gas flowrate less than 85,000 scmd at production sites or 283,000 scmd at natural gas transmission and storage sites, or actual average benzene emissions less than 0.9 Mg/yr). Because we do not have any new emissions data concerning these emission points, we evaluated the dataset collected from industry during the development of the original MACT standards (legacy docket A–94–04, item II–B–01, disk 1 for oil and natural gas production facilities; and items IV–G–24, 26, 27, 30 and 31 for natural gas transmission and storage facilities). We believe this dataset is representative of currently operating glycol dehydrators because it contains information for a varied group of sources (*i.e.,* units owned by different companies, located in different states, representing a range of gas compositions and emission controls) and that the processes have not changed significantly since the data were collected.

In the Oil and Natural Gas Production source category, there were 91 glycol dehydration units with throughput and emissions data identified that would be classified as small glycol dehydration units. We evaluated the possibility of establishing a MACT floor as a Mg/yr limit. However, due to variability of gas throughput and inlet gas composition, we could not properly identify the best performing units by only considering emissions. To allow us to normalize the emissions for a more accurate determination of the best performing sources, we created an emission factor in terms of grams BTEX/scm-ppmv for each facility. The emission factor reflects the facility's emission level, taking into consideration its natural gas throughput and inlet natural gas BTEX concentration. To determine the MACT floor for the existing dehydrators, we ranked each unit from lowest to highest, based on their emission factor, to determine the facilities in the top 12 percent of the dataset. The MACT floor was an emission factor of 1.10×10^{-4} grams BTEX/scm-ppmv. To meet this level of emissions, we anticipate that sources will use a variety of options, including, but not limited to, routing emissions to a condenser or to a combustion device.

We also considered beyond-the-floor options for the existing sources, as required by section 112(d)(2) of the CAA. To achieve further reductions beyond the MACT floor level of control, sources would have to install an additional add-on control device, most likely a combustion device. Assuming the MACT floor control device is a combustion device, which generally achieves at least a 95-percent HAP reduction, then less than 5 percent of the initial HAP emissions remain. Installing a second device would involve the same costs as the first control, but would only achieve 1⁄20 of the reduction (*i.e.,* reducing the remaining 5 percent by another 95 percent represents a 4.49-percent reduction of the initial, uncontrolled emissions, which is 1⁄20 of the 95-percent reduction achieved with the first control). Based on the $8,360/Mg cost effectiveness of the floor level of control, we estimate that the incremental cost effectiveness of the second control to be $167,200/Mg. We do not believe this cost to be reasonable given the level of emission reduction. We are, therefore, proposing an emission standard for existing small dehydrators that reflects the MACT floor.

For new small glycol dehydrators in the Oil and Natural Gas Production source category, based on our performance ranking, the best performing source has an emission factor of 4.66×10^{-6} grams BTEX/scm-ppmv. To meet this level of emissions, we anticipate that sources will use a variety of options, including, but not limited to, routing emissions to a condenser or to a combustion device. The consideration of beyond-the-floor options for new small dehydrators would be the same as for existing small dehydrators, and, as stated above, we do not believe a cost of $167,200/Mg to be reasonable given the level of emission reduction. We are, therefore, proposing a MACT standard for new small dehydrators that reflects the MACT floor level of control.

Under our proposal, a small dehydrator's actual MACT emission limit would be determined by multiplying the MACT floor emission factor in g BTEX/scm-ppmv by its unit-specific incoming natural gas throughput and BTEX concentration for the dehydrator. A formula is provided in 40 CFR 63.765(b)(1)(iii) to calculate the MACT limit as an annual value.

In the Natural Gas Transmission and Storage source category, there were 16 facilities for which throughput and emissions data were available that would be classified as small glycol dehydration units. Since the number of units was less than 30, the MACT floor for existing sources was based on the top five performing units. Using the same emission factor concept, we determined that the MACT floor for existing sources is an emission factor equal to 6.42×10^{-5} grams BTEX/scm-ppmv. To meet this level of emissions, we anticipate that sources will use a variety of options, including, but not limited to, routing emissions to a condenser or to a combustion device.

We also considered beyond-the-floor options for the existing small dehydrators as required by section 112(d)(2) of the CAA. To achieve further reductions beyond the MACT floor level of control, sources would have to install an additional add-on control device, most likely a combustion device. Assuming the MACT floor control device is a combustion device, which generally achieves at least a 95-percent HAP reduction, then less than 5 percent of the initial HAP emissions remain. Installing a second device would involve the same costs as the first control device, but would only achieve 1/20 of the reduction (*i.e.,* reducing the remaining 5 percent by another 95 percent represents a 4.49-percent reduction of the initial, uncontrolled emissions, which is 1/20 of the 95-percent reduction achieved with the first control). Based on the $1,650/Mg cost effectiveness of the floor level of control, we estimate that the incremental cost effectiveness of the second control to be $33,000/Mg. We do not believe this cost to be reasonable given the level of emission reduction. We are, therefore, proposing an emission standard for existing small dehydrators that reflects the MACT floor.

For new small glycol dehydrators, based on our performance ranking, the best performing source has an emission factor of 1.10×10^{-5} grams BTEX/scm-ppmv. To meet this level of emissions, we anticipate that sources will use a variety of options, including, but not limited to, routing emissions to a condenser or to a combustion device. The consideration of beyond-the-floor options for new small dehydrators would be the same as for existing small dehydrators, and, as stated above, we do not believe a cost of $33,000/Mg to be reasonable given the level of emission reduction. We are, therefore, proposing an emission standard for new sources that reflects the MACT floor level of control.

Under our proposal, a source's actual MACT emissions limit would be determined by multiplying this emission factor by their unit-specific incoming natural gas throughput and BTEX concentration for the dehydrator. A formula is provided in 40 CFR 63.1275(b)(1)(iii) to calculate the limit as an annual value.

As discussed below, we are proposing that, with the removal of the 1-ton alternative compliance option from the existing standards for glycol dehydrators, the MACT for these two source categories would provide an ample margin of safety to protect public health. We, therefore, maintain that, after the implementation of the small dehydrator standards discussed above, these MACT will continue to provide an ample margin of safety to protect public health. Consequently, we do not believe it will be necessary to conduct another residual risk review under CAA section 112(f) for these two source categories 8 years following promulgation of the small dehydrator standards merely due to the addition of these new MACT requirements.

2. Storage Vessels

Crude oil, condensate and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically located at tank batteries. A tank battery refers to the collection of process components used to separate, treat and store crude oil, condensate, natural gas and produced water. The extracted products from productions wells enter the tank battery through the production header, which may collect product from many wells.

Emissions from storage vessels are a result of working, breathing and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus, allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flashing emission will occur in the storage stage. Temperature of the liquid may also influence the amount of flash emissions.

In the Oil and Natural Gas Production NESHAP (40 CFR part 63, subpart HH), the MACT standards for storage vessels apply only to those with the PFE. Storage vessels with the PFE are defined as storage vessels that contain hydrocarbon liquids that meet the following criteria:

- A stock tank gas to oil ratio (GOR) greater than or equal to 0.31 cubic meters per liter (m^3/liter); and
- An American Petroleum Institute (API) gravity greater than or equal to 40 degrees; and
- An actual annual average hydrocarbon liquid throughput greater than or equal to 79,500 liters per day (liter/day).

Accordingly, there is no emission limit in the existing MACT for storage vessels without the PFE. However, the MACT analysis performed at the time indicates that the MACT floor was based on all storage vessels, not just those vessels with flash emissions. See, *Recommendation of MACT Floor Levels for HAP Emission Points at Major Sources in the Oil and Natural Gas Production Source Category,* (September 23, 1997, Docket A–94–04, Item II–A–07). We, therefore, propose to apply the existing MACT for storage vessels with PFE to all storage vessels (*i.e.,* storage vessels with the PFE, as well as those without the PFE).

3. Definition of Associated Equipment

CAA section 112(n)(4)(A) provides:

> Notwithstanding the provisions of subsection (a), emissions from any oil or gas exploration or production well (with its associated equipment) and emission from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in contiguous area or under common control, to determine whether such units or stations are major sources.

As stated above, the CAA prevents aggregation of HAP emissions from wells and associated equipment in making major source determinations. In the absence of clear guidance in the statute on what constitutes ''associated equipment,'' the EPA sought to define ''associated equipment'' in a way that recognizes the need to implement relief for this industry as Congress intended and that also allow for the appropriate regulation of significant emission points. 64 FR at 32619. Accordingly, in the existing Oil and Natural Gas Production NESHAP (1998 and 1999 NESHAP), the EPA defined ''associated equipment'' to exclude glycol dehydration units and storage vessels with PFE (thus allowing their emissions to be included in determining major source status) because EPA identified these sources as substantial contributors to HAP emissions. *Id.* EPA explained in that NESHAP that, because a single storage vessel with flash emissions may emit several Mg of HAP per year and individual glycol dehydrators may emit above the major source level, storage vessels with PFE and glycol dehydrators are large individual sources of HAP, 63 FR 6288, 6301 (1998). The EPA therefore considered these emission sources substantial contributors to HAP emissions and excluded them from the definition of ''associated equipment.'' 64 FR at 32619. We have recently examined HAP emissions from storage vessels without flash emissions and found that these emissions are significant and comparable to those vessels with flash emissions. For example, one storage vessel with an API gravity of 30 degrees and a GOR of 2.09 $\times 10^{-3}$ m^3/liter with a throughput of 79,500 liter/day had HAP emissions of 9.91 Mg/yr, including 9.45 Mg/yr of n-hexane.

Because storage vessels without the PFE can have significant emissions at levels that are comparable to emissions from storage vessels with the PFE, there is no appreciable difference between storage vessels with the PFE and those without the PFE for purposes of defining ''associated equipment.'' We are, therefore, proposing to amend the associated equipment definition to exclude all storage vessels and not just storage vessels with the PFE.

C. How did we perform the risk assessment and what are the results and proposed decisions?

1. How did we estimate risks posed by the source categories?

The EPA conducted risk assessments that provided estimates for each source in a category of the MIR posed by the HAP emissions, the HI for chronic exposures to HAP with the potential to cause noncancer health effects, and the hazard quotient (HQ) for acute exposures to HAP with the potential to cause noncancer health effects. The assessments also provided estimates of the distribution of cancer risks within the exposed populations, cancer incidence and an evaluation of the potential for adverse environmental effects for each source category. The risk assessments consisted of seven primary steps, as discussed below. The docket for this rulemaking contains the following document which provides more information on the risk assessment inputs and models: *Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories.* The methods used to assess risks (as described in the seven primary steps below) are consistent with those peer-reviewed by a panel of the EPA's Science Advisory Board (SAB) in 2009 and described in their peer review report issued in 2010 [14]; they are also consistent with the key recommendations contained in that report.

a. Establishing the Nature and Magnitude of Actual Emissions and Identifying the Emissions Release Characteristics

As discussed in section VII.A of this preamble, we used a dataset based on the 2005 NEI as the basis for the risk assessment. In addition to the quality assurance (QA) of the facilities contained in the dataset, we also checked the coordinates of every facility in the dataset through visual observations using tools such as GoogleEarth and ArcView. Where coordinates were found to be incorrect, we identified and corrected them to the extent possible. We also performed QA of the emissions data and release characteristics to ensure there were no outliers.

b. Establishing the Relationship Between Actual Emissions and MACT-Allowable Emissions Levels

The available emissions data in the MACT dataset represent the estimates of mass of emissions actually emitted during the specified annual time period. These ''actual'' emission levels are often lower than the emission levels that a facility might be allowed to emit and still comply with the MACT standards. The emissions level allowed to be emitted by the MACT standards is referred to as the ''MACT-allowable'' emissions level. This represents the highest emissions level that could be emitted by the facility without violating the MACT standards.

We discussed the use of both MACT-allowable and actual emissions in the final Coke Oven Batteries residual risk rule (70 FR 19998–19999, April 15, 2005) and in the proposed and final Hazardous Organic NESHAP residual risk rules (71 FR 34428, June 14, 2006, and 71 FR 76609, December 21, 2006, respectively). In those previous actions, we noted that assessing the risks at the MACT-allowable level is inherently reasonable since these risks reflect the maximum level sources could emit and still comply with national emission standards. But we also explained that it is reasonable to consider actual emissions, where such data are available, in both steps of the risk analysis, in accordance with the Benzene NESHAP. (54 FR 38044, September 14, 1989.)

To estimate emissions at the MACT-allowable level, we developed a ratio of MACT-allowable to actual emissions for each emissions source type in each source category, based on the level of control required by the MACT standards compared to the level of reported actual emissions and available information on the level of control achieved by the emissions controls in use.

c. Conducting Dispersion Modeling, Determining Inhalation Exposures and Estimating Individual and Population Inhalation Risks

Both long-term and short-term inhalation exposure concentrations and health risks from each source in the source categories addressed in this proposal were estimated using the Human Exposure Model (HEM) (Community and Sector HEM–3 version 1.1.0). The HEM–3 performs three primary risk assessment activities: (1) Conducting dispersion modeling to estimate the concentrations of HAP in ambient air, (2) estimating long-term and short-term inhalation exposures to individuals residing within 50 km of the modeled sources and (3) estimating individual and population-level inhalation risks using the exposure estimates and quantitative dose-response information.

The dispersion model used by HEM–3 is AERMOD, which is one of the EPA's preferred models for assessing pollutant concentrations from industrial facilities.[15] To perform the dispersion modeling and to develop the preliminary risk estimates, HEM–3 draws on three data libraries. The first is a library of meteorological data,

[14] U.S. EPA SAB. *Risk and Technology Review (RTR) Risk Assessment Methodologies: For Review by the EPA's Science Advisory Board with Case Studies—MACT I Petroleum Refining Sources and Portland Cement Manufacturing,* May 2010.

[15] U.S. EPA. Revision to the *Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions* (70 FR 68218, November 9, 2005).

which is used for dispersion calculations. This library includes 1 year of hourly surface and upper air observations for more than 158 meteorological stations, selected to provide coverage of the United States and Puerto Rico. A second library of United States Census Bureau census block [16] internal point locations and populations provides the basis of human exposure calculations (Census, 2000). In addition, for each census block, the census library includes the elevation and controlling hill height, which are also used in dispersion calculations. A third library of pollutant unit risk factors and other health benchmarks is used to estimate health risks. These risk factors and health benchmarks are the latest values recommended by the EPA for HAP and other toxic air pollutants. These values are available at *http://www.epa.gov/ttn/atw/toxsource/summary.html* and are discussed in more detail later in this section.

In developing the risk assessment for chronic exposures, we used the estimated annual average ambient air concentration of each of the HAP emitted by each source for which we have emissions data in the source category. The air concentrations at each nearby census block centroid were used as a surrogate for the chronic inhalation exposure concentration for all the people who reside in that census block. We calculated the MIR for each facility as the cancer risk associated with a continuous lifetime (24 hours per day, 7 days per week, and 52 weeks per year for a 70-year period) exposure to the maximum concentration at the centroid of an inhabited census block. Individual cancer risks were calculated by multiplying the estimated lifetime exposure to the ambient concentration of each of the HAP (in micrograms per cubic meter) by its unit risk estimate (URE), which is an upper bound estimate of an individual's probability of contracting cancer over a lifetime of exposure to a concentration of 1 microgram of the pollutant per cubic meter of air. For residual risk assessments, we generally use URE values from the EPA's Integrated Risk Information System (IRIS). For carcinogenic pollutants without the EPA IRIS values, we look to other reputable sources of cancer dose-response values, often using California EPA (CalEPA) URE values, where available. In cases where new, scientifically credible dose-response values have been developed in a manner consistent with the EPA guidelines and have undergone a peer review process similar to that used by the EPA, we may use such dose-response values in place of or in addition to other values, if appropriate.

Formaldehyde is a unique case. In 2004, the EPA determined that the Chemical Industry Institute of Toxicology (CIIT) cancer dose-response value for formaldehyde (5.5×10^{-9} per $\mu g/m^3$) was based on better science than the IRIS cancer dose-response value (1.3×10^{-5} per $\mu g/m^3$) and we switched from using the IRIS value to the CIIT value in risk assessments supporting regulatory actions. However, subsequent research published by the EPA suggests that the CIIT model was not appropriate and in 2010 the EPA returned to using the 1991 IRIS value, which is more health protective.[17] The EPA has been working on revising the formaldehyde IRIS assessment and the National Academy of Sciences (NAS) completed its review of the EPA's draft in May of 2011. EPA is reviewing the public comments and the NAS independent scientific peer review, and the draft IRIS assessment will be revised and the final assessment will be posted on the IRIS database. In the interim, we will present findings using the 1991 IRIS value as a primary estimate, and may also consider other information as the science evolves.

In the case of benzene, the high end of the reported cancer URE range was used in our assessments to provide a conservative estimate of potential cancer risks. Use of the high end of the range provides risk estimates that are approximately 3.5 times higher than use of the equally-plausible low end value. We also evaluated the impact of using the low end of the URE range on our risk results.

We also note that polycyclic organic matter (POM), a carcinogenic HAP with a mutagenic mode of action, is emitted by some of the facilities in these two categories.[18] For this compound group,[19] the age-dependent adjustment factors (ADAF) described in the EPA's *Supplemental Guidance for Assessing Susceptibility from Early-Life Exposure to Carcinogens* [20] were applied. This adjustment has the effect of increasing the estimated lifetime risks for POM by a factor of 1.6. In addition, although only a small fraction of the total POM emissions were not reported as individual compounds, the EPA expresses carcinogenic potency for compounds in this group in terms of benzo[a]pyrene equivalence, based on evidence that carcinogenic POM has the same mutagenic mechanism of action as benzo[a]pyrene. For this reason, the EPA's Science Policy Council [21] recommends applying the *Supplemental Guidance* to all carcinogenic polycyclic aromatic hydrocarbons for which risk estimates are based on relative potency. Accordingly, we have applied the ADAF to the benzo[a]pyrene equivalent portion of all POM mixtures.

Incremental individual lifetime cancer risks associated with emissions from the source category were estimated as the sum of the risks for each of the carcinogenic HAP (including those classified as carcinogenic to humans, likely to be carcinogenic to humans and suggestive evidence of carcinogenic potential [22]) emitted by the modeled source. Cancer incidence and the distribution of individual cancer risks for the population within 50 km of any source were also estimated for the source category as part of these assessments by summing individual risks. A distance of 50 km is consistent with both the analysis supporting the 1989 Benzene NESHAP (54 FR 38044) and the limitations of Gaussian dispersion models, including AERMOD.

To assess risk of noncancer health effects from chronic exposures, we summed the HQ for each of the HAP that affects a common target organ system to obtain the HI for that target organ system (or target organ-specific HI, TOSHI). The HQ for chronic exposures is the estimated chronic

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[16] A census block is generally the smallest geographic area for which census statistics are tabulated.

[17] For details on the justification for this decision, see the memorandum in the docket from Peter Preuss to Steve Page entitled, *Recommendation for Formaldehyde Inhalation Cancer Risk Values,* January 22, 2010.

[18] U.S. EPA. Performing risk assessments that include carcinogens described in the *Supplemental Guidance* as having a mutagenic mode of action. *Science Policy Council Cancer Guidelines Implementation Work Group Communication II:* Memo from W.H. Farland, dated October 4, 2005.

[19] See the *Risk Assessment for Source Categories* document available in the docket for a list of HAP with a mutagenic mode of action.

[20] U.S. EPA. *Supplemental Guidance for Assessing Early-Life Exposure to Carcinogens.* EPA/630/R–03/003F, 2005. *http://www.epa.gov/ttn/atw/childrens_supplement_final.pdf.*

[21] U.S. EPA. *Science Policy Council Cancer Guidelines Implementation Workgroup Communication II:* Memo from W.H. Farland, dated June 14, 2006.

[22] These classifications also coincide with the terms "known carcinogen, probable carcinogen and possible carcinogen," respectively, which are the terms advocated in the EPA's previous *Guidelines for Carcinogen Risk Assessment,* published in 1986 (51 FR 33992, September 24, 1986). Summing the risks of these individual compounds to obtain the cumulative cancer risks is an approach that was recommended by the EPA's SAB in their 2002 peer review of EPA's NATA entitled, *NATA—Evaluating the National-scale Air Toxics Assessment 1996 Data—an SAB Advisory,* available at: *http://yosemite.epa.gov/sab/sabproduct.nsf/214C6E915BB04E14852570CA007A682C/$File/ecadv02001.pdf.*

exposure divided by the chronic reference level, which is either the EPA reference concentration (RfC), defined as ''an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime,'' or, in cases where an RfC from the EPA's IRIS database is not available, the EPA will utilize the following prioritized sources for our chronic dose-response values: (1) The Agency for Toxic Substances and Disease Registry Minimum Risk Level, which is defined as ''an estimate of daily human exposure to a substance that is likely to be without an appreciable risk of adverse effects (other than cancer) over a specified duration of exposure''; (2) the CalEPA Chronic Reference Exposure Level (REL), which is defined as ''the concentration level at or below which no adverse health effects are anticipated for a specified exposure duration''; and (3), as noted above, in cases where scientifically credible dose-response values have been developed in a manner consistent with the EPA guidelines and have undergone a peer review process similar to that used by the EPA, we may use those dose-response values in place of or in concert with other values.

Screening estimates of acute exposures and risks were also evaluated for each of the HAP at the point of highest off-site exposure for each facility (*i.e.,* not just the census block centroids), assuming that a person is located at this spot at a time when both the peak (hourly) emission rate and worst-case dispersion conditions (1991 calendar year data) occur. The acute HQ is the estimated acute exposure divided by the acute dose-response value. In each case, acute HQ values were calculated using best available, short-term dose-response values. These acute dose-response values, which are described below, include the acute REL, acute exposure guideline levels (AEGL) and emergency response planning guidelines (ERPG) for 1-hour exposure durations. As discussed below, we used conservative assumptions for emission rates, meteorology and exposure location for our acute analysis.

As described in the CalEPA's *Air Toxics Hot Spots Program Risk Assessment Guidelines, Part I, The Determination of Acute Reference Exposure Levels for Airborne Toxicants,* an acute REL value (*http://www.oehha.ca.gov/air/pdf/acuterel.pdf*) is defined as ''the concentration level at or below which no adverse health effects are anticipated for a specified exposure duration.'' Acute REL values are based on the most sensitive, relevant, adverse health effect reported in the medical and toxicological literature. Acute REL values are designed to protect the most sensitive individuals in the population by the inclusion of margins of safety. Since margins of safety are incorporated to address data gaps and uncertainties, exceeding the acute REL does not automatically indicate an adverse health impact.

AEGL values were derived in response to recommendations from the National Research Council (NRC). As described in *Standing Operating Procedures (SOP) of the National Advisory Committee on Acute Exposure Guideline Levels for Hazardous Substances (http://www.epa.gov/opptintr/aegl/pubs/sop.pdf),*[23] ''the NRC's previous name for acute exposure levels—community emergency exposure levels—was replaced by the term AEGL to reflect the broad application of these values to planning, response, and prevention in the community, the workplace, transportation, the military, and the remediation of Superfund sites.'' This document also states that AEGL values ''represent threshold exposure limits for the general public and are applicable to emergency exposures ranging from 10 minutes to eight hours.'' The document lays out the purpose and objectives of AEGL by stating (page 21) that ''the primary purpose of the AEGL program and the National Advisory Committee for Acute Exposure Guideline Levels for Hazardous Substances is to develop guideline levels for once-in-a-lifetime, short-term exposures to airborne concentrations of acutely toxic, high-priority chemicals.'' In detailing the intended application of AEGL values, the document states (page 31) that ''[i]t is anticipated that the AEGL values will be used for regulatory and nonregulatory purposes by U.S. Federal and state agencies and possibly the international community in conjunction with chemical emergency response, planning, and prevention programs. More specifically, the AEGL values will be used for conducting various risk assessments to aid in the development of emergency preparedness and prevention plans, as well as real-time emergency response actions, for accidental chemical releases at fixed facilities and from transport carriers.''

The AEGL–1 value is then specifically defined as ''the airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic nonsensory effects. However, the effects are not disabling and are transient and reversible upon cessation of exposure.'' The document also notes (page 3) that, ''Airborne concentrations below AEGL–1 represent exposure levels that can produce mild and progressively increasing but transient and nondisabling odor, taste, and sensory irritation or certain asymptomatic, nonsensory effects.'' Similarly, the document defines AEGL–2 values as ''the airborne concentration (expressed as ppm or mg/m^3) of a substance above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.''

ERPG values are derived for use in emergency response, as described in the American Industrial Hygiene Association's document entitled, *Emergency Response Planning Guidelines (ERPG) Procedures and Responsibilities* (*http://www.aiha.org/1documents/committees/ERPSOPs2006.pdf*) which states that, ''Emergency Response Planning Guidelines were developed for emergency planning and are intended as health based guideline concentrations for single exposures to chemicals.''[24] The ERPG–1 value is defined as ''the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to 1 hour without experiencing other than mild transient adverse health effects or without perceiving a clearly defined, objectionable odor.'' Similarly, the ERPG–2 value is defined as ''the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to 1 hour without experiencing or developing irreversible or other serious health effects or symptoms which could impair an individual's ability to take protective action.''

As can be seen from the definitions above, the AEGL and ERPG values include the similarly-defined severity levels 1 and 2. For many chemicals, a severity level 1 value AEGL or ERPG has not been developed; in these instances, higher severity level AEGL–2 or ERPG–2 values are compared to our modeled

[23] NAS, 2001. *Standing Operating Procedures for Developing Acute Exposure Levels for Hazardous Chemicals,* page 2.

[24] *ERP Committee Procedures and Responsibilities.* November 1, 2006. American Industrial Hygiene Association.

exposure levels to screen for potential acute concerns.

Acute REL values for 1-hour exposure durations are typically lower than their corresponding AEGL–1 and ERPG–1 values. Even though their definitions are slightly different, AEGL–1 values are often the same as the corresponding ERPG–1 values, and AEGL–2 values are often equal to ERPG–2 values. Maximum HQ values from our acute screening risk assessments typically result when basing them on the acute REL value for a particular pollutant. In cases where our maximum acute HQ value exceeds 1, we also report the HQ value based on the next highest acute dose-response value (usually the AEGL–1 and/or the ERPG–1 value).

To develop screening estimates of acute exposures, we developed estimates of maximum hourly emission rates by multiplying the average actual annual hourly emission rates by a factor to cover routinely variable emissions. We chose the factor based on process knowledge and engineering judgment and with awareness of a Texas study of short-term emissions variability, which showed that most peak emission events, in a heavily-industrialized 4-county area (Harris, Galveston, Chambers and Brazoria Counties, Texas) were less than twice the annual average hourly emission rate. The highest peak emission event was 74 times the annual average hourly emission rate, and the 99th percentile ratio of peak hourly emission rate to the annual average hourly emission rate was 9.[25] This analysis is provided in Appendix 4 of the *Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories,* which is available in the docket for this action. Considering this analysis, unless specific process knowledge or data are available to provide an alternate value, to account for more than 99 percent of the peak hourly emissions, we apply a conservative screening multiplication factor of 10 to the average annual hourly emission rate in these acute exposure screening assessments. The factor of 10 was used for both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories.

In cases where acute HQ values from the screening step were less than or equal to 1, acute impacts were deemed negligible and no further analysis was performed. In cases where an acute HQ from the screening step was greater than 1, additional site-specific data were considered to develop a more refined estimate of the potential for acute impacts of concern. The data refinements employed for these source categories consisted of using the site-specific facility layout to distinguish facility property from an area where the public could be exposed. These refinements are discussed in the draft risk assessment document, which is available in the docket for each of these source categories. Ideally, we would prefer to have continuous measurements over time to see how the emissions vary by each hour over an entire year. Having a frequency distribution of hourly emission rates over a year would allow us to perform a probabilistic analysis to estimate potential threshold exceedances and their frequency of occurrence. Such an evaluation could include a more complete statistical treatment of the key parameters and elements adopted in this screening analysis. However, we recognize that having this level of data is rare, hence our use of the multiplier approach.

To better characterize the potential health risks associated with estimated acute exposures to HAP, and in response to a key recommendation from the SAB's peer review of the EPA's RTR risk assessment methodologies,[26] we generally examine a wider range of available acute health metrics than we do for our chronic risk assessments. This is in response to the SAB's acknowledgement that there are generally more data gaps and inconsistencies in acute reference values than there are in chronic reference values. Comparisons of the estimated maximum off-site 1-hour exposure levels are not typically made to occupational levels for the purpose of characterizing public health risks in RTR assessments. This is because they are developed for working age adults and are not generally considered protective for the general public. We note that occupational ceiling values are, for most chemicals, set at levels higher than a 1-hour AEGL–1.

As discussed in section VII.C.2 of this preamble, the maximum estimated worst-case 1-hour exposure to benzene outside the facility fence line for a facility in either source category is 12 mg/m^3. This estimated exposure exceeds the 6-hour REL by a factor of 9 (HQ_{REL} = 9), but is significantly below the 1-hour AEGL–1 (HQ_{AEGL-1} = 0.07). Although this worst-case exposure estimate does not exceed the AEGL–1, we note here that it slightly exceeds workplace ceiling level guidelines designed to protect the worker population for short duration (<15 minute) increases in exposure to benzene, as discussed below. The occupational short-term exposure limit (STEL) standard for benzene developed by the Occupational Safety and Health Administration is 16 mg/m^3, ''as averaged over any 15-minute period.'' [27] Occupational guideline STEL for exposures to benzene have also been developed by the American Conference of Governmental Industrial Hygienists (ACGIH) [28] for less than 15 minutes [29] (ACGIH threshold limit value (TLV)-STEL value of 8.0 mg/m^3), and by the National Institute for Occupational Safety and Health (NIOSH) [30] ''for any 15 minute period in a work day'' (NIOSH REL–STEL of 3.2 mg/m^3). These shorter duration occupational values indicate potential concerns regarding health effects at exposure levels below the 1-hour AEGL–1 value. We solicit comment on the use of the occupational values described above in the interpretation of these worst-case acute screening exposure estimates.

d. Conducting Multi-Pathway Exposure and Risk Modeling

The potential for significant human health risks due to exposures via routes other than inhalation (*i.e.,* multi-pathway exposures) and the potential for adverse environmental impacts were evaluated in a three-step process. In the first step, we determined whether any facilities emitted any HAP known to be PB–HAP (HAP known to be persistent and bio-accumulative) in the environment. There are 14 PB–HAP compounds or compound classes identified for this screening in the EPA's *Air Toxics Risk Assessment Library* (available at *http://www.epa.gov/ttn/fera/risk_atra_vol1.html*). They are cadmium compounds, chlordane, chlorinated dibenzodioxins and furans,

[25] See *http://www.tceq.state.tx.us/compliance/field_ops/eer/index.html* or docket to access the source of these data.

[26] The SAB peer review of RTR Risk Assessment Methodologies is available at: *http://yosemite.epa.gov/sab/sabproduct.nsf/4AB3966E263D943A8525771F00668381/$File/EPA-SAB-10-007-unsigned.pdf.*

[27] 29 CFR 1910.1028, Benzene. Available online at *http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARDS&p_id=10042.*

[28] ACGIH (2001) Benzene. In *Documentation of the TLVs® and BEIs® with Other Worldwide Occupational Exposure Values.* ACGIH, 1300 Kemper Meadow Drive, Cincinnati, OH 45240 (ISBN: 978–1–882417–74–2) and available online at *http://www.acgih.org.*

[29] The ACGIH definition of a TLV–STEL states that ''Exposures above the TLV–TWA up to the TLV–STEL should be less than 15 minutes, should occur no more than four times per day, and there should be at least 60 minutes between successive exposures in this range.''

[30] NIOSH. *Occupational Safety and Health Guideline for Benzene; http://www.cdc.gov/niosh/74-137.html.*

dichlorodiphenyldichloroethylene, heptachlor, hexachlorobenzene, hexachlorocyclohexane, lead compounds, mercury compounds, methoxychlor, polychlorinated biphenyls, POM, toxaphene and trifluralin.

Since one or more of these PB–HAP are emitted by at least one facility in both source categories, we proceeded to the second step of the evaluation. In this step, we determined whether the facility-specific emission rates of each of the emitted PB–HAP were large enough to create the potential for significant non-inhalation human or environmental risks under reasonable worst-case conditions. To facilitate this step, we have developed emission rate thresholds for each PB–HAP using a hypothetical worst-case screening exposure scenario developed for use in conjunction with the EPA's TRIM.FaTE model. The hypothetical screening scenario was subjected to a sensitivity analysis to ensure that its key design parameters were established such that environmental media concentrations were not underestimated (*i.e.,* to minimize the occurrence of false negatives or results that suggest that risks might be acceptable when, in fact, actual risks are high) and to also minimize the occurrence of false positives for human health endpoints. We call this application of the TRIM.FaTE model TRIM–Screen. The facility-specific emission rates of each of the PB–HAP in each source category were compared to the TRIM–Screen emission threshold values for each of the PB–HAP identified in the source category datasets to assess the potential for significant human health risks or environmental risks via non-inhalation pathways.

There was only one facility in the Natural Gas Transmission and Storage source category with reported emissions of PB–HAP, and the emission rates were less than the emission threshold values. There were 29 facilities in the Oil and Natural Gas Production source category with reported emissions of PB–HAP, and one of these had emission rates greater than the emission threshold values. In this case, the emission threshold value for POM was exceeded by a factor of 6. For POM, dairy, vegetables and fruits were the three most dominant exposure pathways driving human exposures in the hypothetical screening exposure scenario. The single facility with emissions exceeding the emission threshold value for POM is located in a highly industrialized area. Therefore, since the exposure pathways which would drive high human exposure are not locally available, multi-pathway exposures and environmental risks were deemed negligible, and no further analysis was performed. For further information on the multi-pathway analysis approach, see the residual risk documentation.

e. Assessing Risks Considering Emissions Control Options

In addition to assessing baseline inhalation risks and screening for potential multi-pathway risks, where appropriate, we also estimated risks considering the potential emission reductions that would be achieved by the particular control options under consideration. In these cases, the expected emissions reductions were applied to the specific HAP and emissions sources in the source category dataset to develop corresponding estimates of risk reductions.

f. Conducting Other Risk-Related Analyses: Facility-Wide Assessments

To put the source category risks in context, we also examined the risks from the entire ''facility,'' where the facility includes all HAP-emitting operations within a contiguous area and under common control. In other words, for each facility that includes one or more sources from one of the source categories under review, we examined the HAP emissions not only from the source category of interest, but also from all other emission sources at the facility. The emissions data for generating these ''facility-wide'' risks were also obtained from the 2005 NEI. For every facility included in the MACT database, we also retrieved emissions data and release characteristics for all other emission sources at the same facility. We estimated the risks due to the inhalation of HAP that are emitted ''facility-wide'' for the populations residing within 50 km of each facility, consistent with the methods used for the source category analysis described above. For these facility-wide risk analyses, the modeled source category risks were compared to the facility-wide risks to determine the portion of facility-wide risks that could be attributed to the source categories addressed in this proposal. We specifically examined the facilities associated with the highest estimates of risk and determined the percentage of that risk attributable to the source category of interest. The risk documentation available through the docket for this action provides the methodology and the results of the facility-wide analyses for each source category.

g. Conducting Other Analyses: Demographic Analysis

To examine the potential for any environmental justice (EJ) issues that might be associated with each source category, we performed a demographic analysis of population risk. In this analysis, we evaluated the distributions of HAP-related cancer and noncancer risks across different social, demographic and economic groups within the populations living near the facilities where these source categories are located. The development of demographic analyses to inform the consideration of EJ issues in the EPA rulemakings is an evolving science. The EPA offers the demographic analyses in this rulemaking to inform the consideration of potential EJ issues and invites public comment on the approaches used and the interpretations made from the results, with the hope that this will support the refinement and improve the utility of such analyses for future rulemakings.

For the demographic analyses, we focus on the populations within 50 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater, or noncancer HI of 1 or greater (based on the emissions of the source category or the facility, respectively). We examine the distributions of those risks across various demographic groups, comparing the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. The results, including other risk metrics, such as average risks for the exposed populations, are documented in source-category-specific technical reports in the docket for both source categories covered in this proposal.

The basis for the risk values used in these analyses were the modeling results based on actual emissions levels obtained from the HEM–3 model described above. The risk values for each census block were linked to a database of information from the 2000 Decennial census that includes data on race and ethnicity, age distributions, poverty status, household incomes and education level. The Census Department Landview® database was the source of the data on race and ethnicity and the data on age distributions, poverty status, household incomes and education level were obtained from the 2000 Census of Population and Housing Summary File 3 Long Form. While race and ethnicity census data are available at the census block level, the age and income census data are only available at the census block group level (which includes an average of 26 blocks or an average of 1,350 people). Where census data are available at the block group level, but not the block level, we assumed that all census blocks within the block group have the same distribution of ages and incomes as the block group.

For each source category, we focused on those census blocks where source category risk results show estimated lifetime inhalation cancer risks above 1-in-1 million or chronic noncancer indices above 1 and determined the relative percentage of different racial and ethnic groups, different age groups, adults with and without a high school diploma, people living in households below the national median income and for people living below the poverty line within those census blocks. The specific census population categories studied include:

- Total population
- White
- African American (or Black)
- Native Americans
- Other races and multiracial
- Hispanic or Latino
- Children 18 years of age and under
- Adults 19 to 64 years of age
- Adults 65 years of age and over
- Adults without a high school diploma
- Households earning under the national median income
- People living below the poverty line

It should be noted that these categories overlap in some instances, resulting in some populations being counted in more than one category (*e.g.,* other races and multiracial and Hispanic). In addition, while not a specific census population category, we also examined risks to ''Minorities,'' a classification which is defined for these purposes as all race population categories except white.

For further information about risks to the populations located near the facilities in these source categories, we also evaluated the estimated distribution of inhalation cancer and chronic noncancer risks associated with the HAP emissions from all the emissions sources at the facility (*i.e.,* facility-wide). This analysis used the facility-wide RTR modeling results and the census data described above.

The methodology and the results of the demographic analyses for each source category are included in a source-category-specific technical report for each of the categories, which are available in the docket for this action.

h. Considering Uncertainties in Risk Assessment

Uncertainty and the potential for bias are inherent in all risk assessments, including those performed for the source categories addressed in this proposal. Although uncertainty exists, we believe that our approach, which used conservative tools and assumptions, ensures that our decisions are health-protective. A brief discussion of the uncertainties in the emissions datasets, dispersion modeling, inhalation exposure estimates and dose-response relationships follows below. A more thorough discussion of these uncertainties is included in the risk assessment documentation (referenced earlier) available in the docket for this action.

i. Uncertainties in the Emissions Datasets

Although the development of the MACT dataset involved QA/quality control processes, the accuracy of emissions values will vary depending on the source of the data, the degree to which data are incomplete or missing, the degree to which assumptions made to complete the datasets are inaccurate, errors in estimating emissions values and other factors. The emission estimates considered in this analysis generally are annual totals for certain years that do not reflect short-term fluctuations during the course of a year or variations from year to year.

The estimates of peak hourly emission rates for the acute effects screening assessment were based on a multiplication factor of 10 applied to the average annual hourly emission rate, which is intended to account for emission fluctuations due to normal facility operations. Additionally, although we believe that we have data for most facilities in these two source categories in our RTR dataset, our dataset may not include data for all existing facilities. Moreover, there are uncertainties with regard to the identification of sources as major or area in the NEI for these source categories.

ii. Uncertainties in Dispersion Modeling

While the analysis employed the EPA's recommended regulatory dispersion model, AERMOD, we recognize that there is uncertainty in ambient concentration estimates associated with any model, including AERMOD. In circumstances where we had to choose between various model options, where possible, model options (*e.g.,* rural/urban, plume depletion, chemistry) were selected to provide an overestimate of ambient air concentrations of the HAP rather than underestimates. However, because of practicality and data limitation reasons, some factors (*e.g.,* meteorology, building downwash) have the potential in some situations to overestimate or underestimate ambient impacts. For example, meteorological data were taken from a single year (1991) and facility locations can be a significant distance from the site where these data were taken. Despite these uncertainties, we believe that at off-site locations and census block centroids, the approach considered in the dispersion modeling analysis should generally yield overestimates of ambient HAP concentrations.

iii. Uncertainties in Inhalation Exposure

The effects of human mobility on exposures were not included in the assessment. Specifically, short-term mobility and long-term mobility between census blocks in the modeling domain were not considered.[31] The assumption of not considering short or long-term population mobility does not bias the estimate of the theoretical MIR, nor does it affect the estimate of cancer incidence since the total population number remains the same. It does, however, affect the shape of the distribution of individual risks across the affected population, shifting it toward higher estimated individual risks at the upper end and reducing the number of people estimated to be at lower risks, thereby increasing the estimated number of people at specific risk levels.

In addition, the assessment predicted the chronic exposures at the centroid of each populated census block as surrogates for the exposure concentrations for all people living in that block. Using the census block centroid to predict chronic exposures tends to over-predict exposures for people in the census block who live further from the facility, and under-predict exposures for people in the census block who live closer to the facility. Thus, using the census block centroid to predict chronic exposures may lead to a potential understatement or overstatement of the true maximum impact, but is an unbiased estimate of average risk and incidence.

The assessments evaluate the cancer inhalation risks associated with continuous pollutant exposures over a 70-year period, which is the assumed lifetime of an individual. In reality, both the length of time that modeled emissions sources at facilities actually operate (*i.e.,* more or less than 70 years), and the domestic growth or decline of the modeled industry (*i.e.,* the increase

[31] Short-term mobility is movement from one micro-environment to another over the course of hours or days. Long-term mobility is movement from one residence to another over the course of a lifetime.

or decrease in the number or size of United States facilities), will influence the risks posed by a given source category. Depending on the characteristics of the industry, these factors will, in most cases, result in an overestimate both in individual risk levels and in the total estimated number of cancer cases. However, in rare cases, where a facility maintains or increases its emission levels beyond 70 years, residents live beyond 70 years at the same location, and the residents spend most of their days at that location, then the risks could potentially be underestimated. Annual cancer incidence estimates from exposures to emissions from these sources would not be affected by uncertainty in the length of time emissions sources operate.

The exposure estimates used in these analyses assume chronic exposures to ambient levels of pollutants. Because most people spend the majority of their time indoors, actual exposures may not be as high, depending on the characteristics of the pollutants modeled. For many of the HAP, indoor levels are roughly equivalent to ambient levels, but for very reactive pollutants or larger particles, these levels are typically lower. This factor has the potential to result in an overstatement of 25 to 30 percent of exposures.[32]

In addition to the uncertainties highlighted above, there are several factors specific to the acute exposure assessment that should be highlighted. The accuracy of an acute inhalation exposure assessment depends on the simultaneous occurrence of independent factors that may vary greatly, such as hourly emissions rates, meteorology, and human activity patterns. In this assessment, we assume that individuals remain for 1 hour at the point of maximum ambient concentration as determined by the co-occurrence of peak emissions and worst-case meteorological conditions. These assumptions would tend to overestimate actual exposures since it is unlikely that a person would be located at the point of maximum exposure during the time of worst-case impact.

iv. Uncertainties in Dose-Response Relationships

There are uncertainties inherent in the development of the dose-response values used in our risk assessments for cancer effects from chronic exposures and noncancer effects from both chronic and acute exposures. Some uncertainties may be considered quantitatively, and others generally are expressed in qualitative terms. We note as a preface to this discussion a point on dose-response uncertainty that is brought out in the *EPA 2005 Cancer Guidelines;* namely, that ''the primary goal of the EPA actions is protection of human health; accordingly, as an Agency policy, risk assessment procedures, including default options that are used in the absence of scientific data to the contrary, should be health protective.'' (*EPA 2005 Cancer Guidelines,* pages 1–7.) This is the approach followed here as summarized in the next several paragraphs. A complete detailed discussion of uncertainties and variability in dose-response relationships is given in the residual risk documentation, which is available in the docket for this action.

Cancer URE values used in our risk assessments are those that have been developed to generally provide an upper bound estimate of risk. That is, they represent a ''plausible upper limit to the true value of a quantity'' (although this is usually not a true statistical confidence limit).[33] In some circumstances, the true risk could be as low as zero; however, in other circumstances, the risk could also be greater.[34] When developing an upper bound estimate of risk and to provide risk values that do not underestimate risk, health-protective default approaches are generally used. To err on the side of ensuring adequate health-protection, the EPA typically uses the upper bound estimates rather than lower bound or central tendency estimates in our risk assessments, an approach that may have limitations for other uses (*e.g.,* priority-setting or expected benefits analysis).

Chronic noncancer reference (RfC and reference dose (RfD)) values represent chronic exposure levels that are intended to be health-protective levels. Specifically, these values provide an estimate (with uncertainty spanning perhaps an order of magnitude) of daily oral exposure (RfD) or of a continuous inhalation exposure (RfC) to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. To derive values that are intended to be ''without appreciable risk,'' the methodology relies upon an uncertainty factor (UF) approach (U.S. EPA, 1993, 1994) which includes consideration of both uncertainty and variability. When there are gaps in the available information, UF are applied to derive reference values that are intended to protect against appreciable risk of deleterious effects. The UF are commonly default values,[35] *e.g.,* factors of 10 or 3, used in the absence of compound-specific data; where data are available, UF may also be developed using compound-specific information. When data are limited, more assumptions are needed and more UF are used. Thus, there may be a greater tendency to overestimate risk in the sense that further study might support development of reference values that are higher (*i.e.,* less potent) because fewer default assumptions are needed. However, for some pollutants, it is possible that risks may be underestimated. While collectively termed ''uncertainty factor,'' these factors account for a number of different quantitative considerations when using observed animal (usually rodent) or human toxicity data in the development of the RfC. The UF are intended to account for: (1) Variation in susceptibility among the members of the human population (*i.e.,* inter-individual variability); (2) uncertainty in extrapolating from experimental animal data to humans (*i.e.,* interspecies differences); (3) uncertainty in extrapolating from data obtained in a study with less-than-lifetime exposure (*i.e.,* extrapolating from sub-chronic to chronic exposure); (4) uncertainty in extrapolating the observed data to obtain an estimate of the exposure associated with no adverse effects; and (5) uncertainty when the database is incomplete or there are problems with the applicability of available studies. Many of the UF used to account for variability and uncertainty in the development of acute reference values

[32] U.S. EPA. *National-Scale Air Toxics Assessment for 1996.* (EPA 453/R–01–003; January 2001; page 85.)

[33] IRIS glossary (*http://www.epa.gov/NCEA/iris/help_gloss.htm*).

[34] An exception to this is the URE for benzene, which is considered to cover a range of values, each end of which is considered to be equally plausible and which is based on maximum likelihood estimates.

[35] According to the NRC report, *Science and Judgment in Risk Assessment* (NRC, 1994) ''[Default] options are generic approaches, based on general scientific knowledge and policy judgment, that are applied to various elements of the risk assessment process when the correct scientific model is unknown or uncertain.'' The 1983 NRC report, *Risk Assessment in the Federal Government: Managing the Process,* defined default option as ''the option chosen on the basis of risk assessment policy that appears to be the best choice in the absence of data to the contrary'' (NRC, 1983a, p. 63). Therefore, default options are not rules that bind the Agency; rather, the Agency may depart from them in evaluating the risks posed by a specific substance when it believes this to be appropriate. In keeping with EPA's goal of protecting public health and the environment, default assumptions are used to ensure that risk to chemicals is not underestimated (although defaults are not intended to overtly overestimate risk). See EPA, 2004, *An Examination of EPA Risk Assessment Principles and Practices,* EPA/100/B–04/001 available at: *http://www.epa.gov/osa/pdfs/ratf-final.pdf.*

are quite similar to those developed for chronic durations, but they more often use individual UF values that may be less than 10. UF are applied based on chemical-specific or health effect-specific information (*e.g.,* simple irritation effects do not vary appreciably between human individuals, hence a value of 3 is typically used), or based on the purpose for the reference value (see the following paragraph). The UF applied in acute reference value derivation include: (1) Heterogeneity among humans; (2) uncertainty in extrapolating from animals to humans; (3) uncertainty in lowest observed adverse effect (exposure) level to no observed adverse effect (exposure) level adjustments; and (4) uncertainty in accounting for an incomplete database on toxic effects of potential concern. Additional adjustments are often applied to account for uncertainty in extrapolation from observations at one exposure duration (*e.g.,* 4 hours) to derive an acute reference value at another exposure duration (*e.g.,* 1 hour).

Not all acute reference values are developed for the same purpose and care must be taken when interpreting the results of an acute assessment of human health effects relative to the reference value or values being exceeded. Where relevant to the estimated exposures, the lack of short-term dose-response values at different levels of severity should be factored into the risk characterization as potential uncertainties.

Although every effort is made to identify peer-reviewed reference values for cancer and noncancer effects for all pollutants emitted by the sources included in this assessment, some HAP continue to have no reference values for cancer or chronic noncancer or acute effects. Since exposures to these pollutants cannot be included in a quantitative risk estimate, an understatement of risk for these pollutants at environmental exposure levels is possible. For a group of compounds that are either unspeciated or do not have reference values for every individual compound (*e.g.,* glycol ethers), we conservatively use the most protective reference value to estimate risk from individual compounds in the group of compounds.

Additionally, chronic reference values for several of the compounds included in this assessment are currently under the EPA IRIS review and revised assessments may determine that these pollutants are more or less potent than the current value. We may re-evaluate residual risks for the final rulemaking if these reviews are completed prior to our taking final action for these source categories and a dose-response metric changes enough to indicate that the risk assessment supporting this notice may significantly understate human health risk.

v. Uncertainties in the Multi-Pathway and Environmental Effects Assessment

We generally assume that when exposure levels are not anticipated to adversely affect human health, they also are not anticipated to adversely affect the environment. For each source category, we generally rely on the site-specific levels of PB–HAP emissions to determine whether a full assessment of the multi-pathway and environmental effects is necessary. As discussed above, we conclude that the potential for these types of impacts is low for these source categories.

vi. Uncertainties in the Facility-Wide Risk Assessment

Given that the same general analytical approach and the same models were used to generate facility-wide risk results as were used to generate the source category risk results, the same types of uncertainties discussed above for our source category risk assessments apply to the facility-wide risk assessments. Additionally, the degree of uncertainty associated with facility-wide emissions and risks is likely greater because we generally have not conducted a thorough engineering review of emissions data for source categories not currently undergoing an RTR review.

vii. Uncertainties in the Demographic Analysis

Our analysis of the distribution of risks across various demographic groups is subject to the typical uncertainties associated with census data (*e.g.,* errors in filling out and transcribing census forms), as well as the additional uncertainties associated with the extrapolation of census-block group data (*e.g.,* income level and education level) down to the census block level.

2. What are the results and proposed decisions from the risk review for the Oil and Natural Gas Production source category?

a. Results of the Risk Assessments and Analyses

We conducted an inhalation risk assessment for the Oil and Natural Gas Production source category. We also conducted an assessment of facility-wide risk. Details of the risk assessments and analyses can be found in the residual risk documentation, which is available in the docket for this action. For informational purposes and to examine the potential for any EJ issues that might be associated with each source category, we performed a demographic analysis of population risks.

i. Inhalation Risk Assessment Results

Table 2 provides an overall summary of the results of the inhalation risk assessment.

TABLE 2—OIL AND NATURAL GAS PRODUCTION INHALATION RISK ASSESSMENT RESULTS

Number of facilities [1]	Maximum individual cancer risk (in 1 million) [2]		Estimated population at risk ≥ 1-in-1 million	Estimated annual cancer incidence (cases per year)	Maximum chronic noncancer TOSHI [4]		Maximum off-site acute noncancer HQ [5]
	Actual emissions level	Allowable emissions level			Actual emissions level	Allowable emissions level	
990	40	100–400 [3]	160,000 [3]	0.007–0.02 [3]	0.1	0.7	HQ_{REL} = 9 (benzene) HQ_{AEGL-1} = 0.07 (benzene)

[1] Number of facilities evaluated in the risk analysis.

[2] Estimated maximum individual excess lifetime cancer risk.

[3] The EPA IRIS assessment for benzene provides a range of equally-plausible URE (2.2E–06 to 7.8E–06 per ug/m3), giving rise to ranges for the estimates of cancer MIR and cancer incidence. Estimated population values are not scalable with benzene URE range, but would be lower using the lower end of the URE range.

[4] Maximum TOSHI. The target organ with the highest TOSHI for the Oil and Natural Gas Production source category is the respiratory system.

[5] The maximum estimated acute exposure concentration was divided by available short-term dose-response values to develop an array of HQ values.

As shown in Table 2, the results of the inhalation risk assessment performed using actual emissions data indicate the maximum lifetime individual cancer risk could be as high as 40-in-1 million, with POM driving the highest risk, and benzene driving risks overall. The total estimated cancer incidence from this source category is 0.02 excess cancer cases per year (0.007 excess cancer cases per year based on the lower end of the benzene URE range), or one case in every 50 years. Approximately 160,000 people are estimated to have cancer risks at or above 1-in-1 million as a result of the emissions from 89 facilities (use of the lower end of the benzene URE range would further reduce this population estimate). The maximum chronic non-cancer TOSHI value for the source category could be up to 0.1 from emissions of naphthalene, indicating no significant potential for chronic noncancer impacts.

As explained above, our analysis of potential differences between actual emission levels and emissions allowable under the oil and natural gas production MACT standard indicate that MACT-allowable emission levels may be up to 50 times greater than actual emission levels. Considering this difference, the risk results from the inhalation risk assessment indicate the maximum lifetime individual cancer risk could be as high as 400-in-1 million (100-in-1 million based on the lower end of the benzene URE range) and the maximum chronic noncancer TOSHI value could be as high as 0.7 at the MACT-allowable emissions level.

ii. Facility-Wide Risk Assessment Results

A facility-wide risk analysis was also conducted based on actual emissions levels. Table 3 displays the results of the facility-wide risk assessment. For detailed facility-specific results, see Table 2 of Appendix 6 of the risk document in the docket for this rulemaking.

TABLE 3—OIL AND NATURAL GAS PRODUCTION FACILITY-WIDE RISK ASSESSMENT RESULTS

Number of facilities analyzed	990
Cancer Risk:	
Estimated maximum facility-wide individual cancer risk (in 1 million)	100
Number of facilities with estimated facility-wide individual cancer risk of 100-in-1 million or more	1
Number of facilities at which the Oil and Natural Gas Production source category contributes 50 percent or more to the facility-wide individual cancer risks of 100-in-1 million or more	0
Number of facilities with facility-wide individual cancer risk of 1-in-1 million or more	140
Number of facilities at which the Oil and Natural Gas Production source category contributes 50 percent or more to the facility-wide individual cancer risk of 1-in-1 million or more	85
Chronic Noncancer Risk:	
Maximum facility-wide chronic noncancer TOSHI	9
Number of facilities with facility-wide maximum noncancer TOSHI greater than 1	10
Number of facilities at which the Oil and Natural Gas Production source category contributes 50 percent or more to the facility-wide maximum noncancer TOSHI of 1 or more	0

The facility-wide MIR from all HAP emissions at a facility that contains sources subject to the oil and natural gas production MACT standards is estimated to be 100-in-1 million, based on actual emissions. Of the 990 facilities included in this analysis, only one has a facility-wide MIR of 100-in-1 million. At this facility, oil and natural gas production accounts for less than 2 percent of the total facility-wide risk. Nickel emissions from oil-fired boilers and formaldehyde emissions from reciprocating internal combustion engines (RICE) contribute essentially all the facility-wide risks at this facility, with over 80 percent of the risk attributed to the nickel emissions.[36] There are 140 facilities with facility-wide MIR of 1-in-1 million or greater. Of these facilities, 85 have oil and natural gas production operations that contribute greater than 50 percent to the facility-wide risks. As discussed above, we are proposing MACT standards for BTEX emissions from small glycol dehydrators in this action. These standards would reduce the risk from benzene emissions at facilities with oil and gas production. Formaldehyde emissions will be assessed under future RTR for RICE.

The facility-wide maximum individual chronic noncancer TOSHI is estimated to be 9 based on actual emissions. Of the 990 facilities included in this analysis, 10 have facility-wide maximum chronic noncancer TOSHI values greater than 1. Of these facilities, none had oil and natural gas production operations that contributed greater than 50 percent to these facility-wide risks. The chronic noncancer risks at these 10 facilities are primarily driven by acrolein emissions from RICE.

iii. Demographic Risk Analysis Results

The results of the demographic analyses performed to investigate the distribution of cancer risks at or above 1-in-1 million among the surrounding population are summarized in Table 4 below. These results, for various demographic groups, are based on actual emissions levels for the population living within 50 km of the facilities.

TABLE 4—OIL AND NATURAL GAS PRODUCTION DEMOGRAPHIC RISK ANALYSIS RESULTS

	Nationwide	Population with cancer risk at or above 1-in-1 million due to	
		Source category HAP emissions	Facility-wide HAP emissions
Total Population	285,000,000	160,000	597,000

[36] We note that there is an ongoing IRIS reassessment for formaldehyde, and that future RTR risk assessments will use the cancer potency for formaldehyde that results from that reassessment. As a result, the current results may not match those of future assessments.

TABLE 4—OIL AND NATURAL GAS PRODUCTION DEMOGRAPHIC RISK ANALYSIS RESULTS—Continued

	Nationwide	Population with cancer risk at or above 1-in-1 million due to	
		Source category HAP emissions	Facility-wide HAP emissions
Race by Percent			
White	75	62	61
All Other Races	25	38	39
Race by Percent			
White	75	62	61
African American	12	12	8
Native American	0.9	0.7	1.3
Other and Multiracial	12	25	30
Ethnicity by Percent			
Hispanic	14	22	34
Non-Hispanic	86	78	66
Income by Percent			
Below Poverty Level	13	14	19
Above Poverty Level	87	86	81
Education by Percent			
Over 25 and without High School Diploma	13	10	16
Over 25 and with a High School Diploma	87	90	84

The results of the Oil and Natural Gas Production source category demographic analysis indicate that there are approximately 160,000 people exposed to a cancer risk at or above 1-in-1 million due to emissions from the source category, including an estimated 38 percent that are classified as minority (listed as ''All Other Races'' in the table above). Of the 160,000 people with estimated cancer risks at or above 1-in-1 million from the source category, 25 percent are in the ''Other and Multiracial'' demographic group, 22 percent are in the ''Hispanic or Latino'' demographic group, and 14 percent are in the ''Below Poverty Level'' demographic group, results which are 13, 8 and 1 percentage points higher, respectively, than the respective percentages for these demographic groups across the United States. The percentages for the other demographic groups are lower than their respective nationwide percentages. The table also shows that there are approximately 597,000 people exposed to an estimated cancer risk at or above 1-in-1 million due to facility-wide emissions, including 30 percent in the ''Other and Multiracial'' demographic group, 34 percent in the ''Hispanic or Latino'' demographic group, 1.3 percent in the ''Native American'' demographic group and 16 percent in the ''Over 25 and without High School Diploma'' demographic group, results which are 18, 2, 0.4 and 3 percentage points higher than the percentages for these demographic groups across the United States, respectively. The percentages for the other demographic groups are lower than their respective nationwide percentages.

b. What are the proposed risk decisions for the Oil and Natural Gas Production source category?

i. Risk Acceptability

In the risk analysis we performed for this source category, pursuant to CAA section 112(f)(2), we considered the available health information—the MIR; the numbers of persons in various risk ranges; cancer incidence; the maximum noncancer HI; the maximum acute noncancer hazard; the extent of noncancer risks; the potential for adverse environmental effects; and distribution of risks in the exposed population; and risk estimation uncertainty (54 FR 38044, September 14, 1989).

For the Oil and Natural Gas Production source category, the risk analysis we performed indicates that the cancer risks to the individual most exposed could be as high as 40-in-1 million due to actual emissions and as high as 400-in-1 million due to MACT-allowable emissions (100-in-1 million, based on the lower end of the benzene URE range). While the 40-in-1 million risk due to actual emissions is considerably less than 100-in-1 million, which is the presumptive limit of acceptability, the 400-in-1 million risk due to allowable emissions is considerably higher and is considered unacceptable. We do note, however, that the risk analysis shows low cancer incidence (1 case in every 50 years), low potential for adverse environmental effects or human health multi-pathway effects and that chronic noncancer health impacts are unlikely.

We also conclude that acute noncancer health impacts are unlikely. As discussed above, screening estimates of acute exposures and risks were evaluated for each of the HAP at the point of highest off-site exposure for each facility (*i.e.,* not just the census block centroids) assuming that a person is located at this spot at a time when both the peak emission rate and worst-case dispersion conditions occur. Under these worst-case conditions, we estimate benzene acute HQ values (based on the REL) could be as high as 9. Although the REL (which indicates the level below which adverse effects are not anticipated) is exceeded in this case, we believe the potential for acute effects is low for several reasons. First, the acute modeling scenario is worst-case because of the confluence of peak emission rates and worst-case dispersion conditions.

Second, the benzene REL is based on a 6-hour exposure duration because a 1-hour exposure duration value was unavailable. An REL based on a 6-hour exposure duration is generally lower than an REL based on a 1-hour exposure duration and, consequently, easier to exceed. Also, although there are exceedances of the REL, the highest estimated 1-hour exposure is less than 10 percent of the AEGL–1 value, which is a level at which effects could be experienced. Finally, the generally sparse populations near these facilities make it less likely that a person would be near the plant to be exposed. For example, in the two cases where the acute HQ value is as high as 9, there are only 30 people associated with the census blocks within 2 miles of the two facilities.

While our additional analysis of facility-wide risks showed that there is one facility with maximum facility-wide cancer risk of 100-in-1 million or greater and 10 facilities with a maximum chronic noncancer TOSHI greater than 1, it also showed that oil and natural gas production operations did not drive these risks.

In determining whether risk is acceptable, we considered the available health information, as described above. In this case, although a number of factors we considered indicate relatively low risk concern, we are proposing to determine that the risks are unacceptable, in large part, because the MIR is 400-in-1 million due to MACT-allowable emissions, which greatly exceeds the ''presumptive limit on maximum individual lifetime risk of approximately 1-in-10 thousand [100-in-1 million] recognized in the Benzene NESHAP (54 FR 38045).'' The MIR, based on MACT-allowable emissions, is driven by the allowable emissions of 0.9 Mg/yr benzene under the MACT as a compliance option. We are, therefore, proposing to eliminate the alternative compliance option of 0.9 Mg/yr benzene from the existing glycol dehydrator MACT requirements. With this change, the source category MIR, based on MACT-allowable emissions, would be reduced to 40-in-1 million, which we find acceptable in light of all the other factors considered. Thus, we are proposing that the risks from the Oil and Natural Gas Production source category are acceptable, with the removal of the alternative compliance option of 0.9 Mg/yr benzene limit from the current glycol dehydrator MACT requirements.

Pursuant to CAA section 112(f)(4), we are proposing that this change (*i.e.,* removal of the 0.9 Mg/yr compliance alternative) apply 90 days after its effective date. We are requesting comment on whether or not this is sufficient time for the large dehydrators that have been relying on this compliance alternative to come into compliance with the 95-percent control requirement or if additional time is needed. See CAA section 112(f)(4)(A).

We recognize that our proposal to remove the 0.9 Mg/yr compliance alternative for the 95-percent control glycol dehydrator MACT standard could have negative impacts on some sources that have come to rely on the flexibility this alternative provides. We solicit comment on any such impacts and whether such impacts warrant adding a different compliance alternative that would result in less risk than the 0.9 Mg/yr benzene limit compliance option. If a commenter suggests a different compliance alternative, the commenter should explain, in detail, what that alternative would be, how it would work and how it would reduce risk.

ii. Ample Margin of Safety

We next considered whether this revised standard (existing MACT plus removal of 0.9 Mg/yr benzene compliance option) provides an ample margin of safety. In this analysis, we investigated available emissions control options that might reduce the risk associated with emissions from the source category and considered this information along with all of the health risks and other health information considered in the risk acceptability determination.

For glycol dehydrators, we considered the addition of a second control device in the same manner that was discussed in the floor evaluation in section VII.B.1 above. The cost effectiveness associated with that option would be $167,200/Mg, which we believe is too high to require additional controls on glycol dehydrators.

Similarly, we considered the addition of a second control device to the required MACT floor control device (cost effectiveness of $18,300/Mg). Similar to our discussion of beyond-the-MACT-floor controls for glycol dehydrators in section VII.B.1 of this preamble, the incremental cost to add a second control device for storage vessels would be approximately 20 times higher than the MACT floor cost effectiveness, or $366,000/Mg. We do not believe this cost effectiveness is reasonable.

For leak detection, we considered implementation of LDAR programs that are more stringent than the current standards. An assessment performed for various LDAR options under the NSPS in section VI.B.4.b of this preamble yielded the lowest cost effectiveness of $5,170/Mg ($4,700/ton) for control of VOC for the options evaluated. A LDAR program to control HAP would involve similar costs for equipment, labor, etc., to those considered in the NSPS assessment, but since there is approximately 20 times less HAP than VOC present in material handled in regulated equipment, the cost effectiveness to control HAP would be approximately 20 times greater (*i.e.,* $100,000/Mg) for HAP, which we believe is not reasonable.

In accordance with the approach established in the Benzene NESHAP, the EPA weighed all health risk measures and information considered in the risk acceptability determination, along with the costs and economic impacts of emissions controls, technological feasibility, uncertainties and other relevant factors in making our ample margin of safety determination. Considering the health risk information and the high cost effectiveness of the options identified, we propose that the existing MACT standards, with the removal of the 1 tpy benzene limit compliance option from the glycol dehydrator standards, provide an ample margin of safety to protect public health.

While we are proposing that the oil and natural gas production MACT standards (with the removal of the alternative compliance option of 1 tpy benzene limit) provide an ample margin of safety to protect public health, we are concerned about the estimated facility-wide risks identified through these screening analyses. As described previously, the highest estimated facility-wide cancer risks are mostly due to emissions from oil fired boilers and RICE. Both of these sources are regulated under other source categories and we anticipate that emission reductions from those sources will occur as standards for those source categories are implemented.

3. What are the results and proposed decisions from the risk review for the Natural Gas Transmission and Storage source category?

a. Results of the Risk Assessments and Analyses

We conducted an inhalation risk assessment for the Natural Gas Transmission and Storage source category. We also conducted an assessment of facility-wide risk and performed a demographic analysis of population risks. Details of the risk assessments and analyses can be found in the residual risk documentation, which is available in the docket for this action.

i. Inhalation Risk Assessment Results

Table 5 provides an overall summary of the results of the inhalation risk assessment. For informational purposes and to examine the potential for any EJ issues that might be associated with each source category, we performed a demographic analysis of population risks.

TABLE 5—NATURAL GAS TRANSMISSION AND STORAGE INHALATION RISK ASSESSMENT RESULTS

Number of Facilities [1]	Maximum individual cancer risk (in 1 million) [2]		Estimated population at risk ≥ 1-in-1 million	Estimated annual cancer incidence (cases per year)	Maximum chronic noncancer TOSHI [4]		Maximum off-site acute noncancer HQ [5]
	Actual emissions level	Allowable emissions level			Actual emissions level	Allowable emissions level	
321	[3] 30–90	[3] 30–90	[3] 2,500	[3] 0.0003–0.001	0.4	0.8	HQ_{REL} = 5 (benzene) HQ_{AEGL-1} = 0.2 (chlorobenzene)

[1] Number of facilities evaluated in the risk analysis.
[2] Estimated maximum individual excess lifetime cancer risk.
[3] The EPA IRIS assessment for benzene provides a range of equally-plausible URE (2.2E–06 to 7.8E–06 per ug/m^3), giving rise to ranges for the estimates of cancer MIR and cancer incidence. Estimated population values are not scalable with benzene URE range, but would be lower using the lower end of the URE range.
[4] Maximum TOSHI. The target organ with the highest TOSHI for the Natural Gas Transmission and Storage source category is the immune system.
[5] The maximum estimated acute exposure concentration was divided by available short-term dose-response values to develop an array of HQ values.

As shown in Table 5 above, the results of the inhalation risk assessment performed using actual emissions data indicate the maximum lifetime individual cancer risk could be as high as 90-in-1 million, (30-in-1 million based on the lower end of the benzene URE range), with benzene as the major contributor to the risk. The total estimated cancer incidence from the source category is 0.001 excess cancer cases per year (0.0003 excess cancer cases per year based on the lower end of the benzene URE range), or one case in every polycyclic organic matter 1,000 years. Approximately 2,500 people are estimated to have cancer risks at or above 1-in-1 million as a result of the emissions from 15 facilities (use of the lower end of the benzene URE range would further reduce this population estimate). The maximum chronic noncancer TOSHI value for the source category could be up to 0.4 from emissions of benzene, indicating no significant potential for chronic noncancer impacts.

As explained above in section VII.C.1.b, our analysis of potential differences between actual emission levels and emissions allowable under the natural gas transmission and storage MACT standard indicate that MACT-allowable emission levels may be up to 50 times greater than actual emission levels at some sources. However, because some sources are emitting at the level allowed under the current NESHAP, the risk results from the inhalation risk assessment indicate the maximum lifetime individual cancer risk would still be 90-in-1 million (30-in-1 million based on the lower end of the benzene URE range), based on both actual and allowable emission levels, and the maximum chronic noncancer TOSHI value could be as high as 0.8 at the MACT-allowable emissions level.

ii. Facility-Wide Risk Assessment Results

A facility-wide risk analysis was also conducted based on actual emissions levels. Table 6 below displays the results of the facility-wide risk assessment. For detailed facility-specific results, see Table 2 of Appendix 6 of the risk document in the docket for this rulemaking.

TABLE 6—NATURAL GAS TRANSMISSION AND STORAGE FACILITY-WIDE RISK ASSESSMENT RESULTS

Number of Facilities Analyzed	321
Cancer Risk:	
Estimated maximum facility-wide individual cancer risk (in 1 million)	[1] 200
Number of facilities with estimated facility-wide individual cancer risk of 100-in-1 million or more	3
Number of facilities at which the Natural Gas Transmission and Storage source category contributes 50 percent or more to the facility-wide individual cancer risks of 100-in-1 million or more	1
Number of facilities with facility-wide individual cancer risk of 1-in-1 million or more	74
Number of facilities at which the Natural Gas Transmission and Storage source category contributes 50 percent or more to the facility-wide individual cancer risk of 1-in-1 million or more	10
Chronic Noncancer Risk:	
Maximum facility-wide chronic noncancer TOSHI	80
Number of facilities with facility-wide maximum noncancer TOSHI greater than 1	30
Number of facilities at which the Natural Gas Transmission and Storage source category contributes 50 percent or more to the facility-wide maximum noncancer TOSHI of 1 or more	0

[1] We note that the MIR would be 100-in-1 million if the CIIT URE for formaldehyde were used instead of the IRIS URE.

The facility-wide MIR from all HAP emissions at any facility that contains sources subject to the natural gas transmission and storage MACT standards is estimated to be 200-in-1 million, based on actual emissions. Of the 321 facilities included in this analysis, three have facility-wide MIR of 100-in-1 million or greater. The facility-wide MIR is 200-in-1 million at two of these facilities, driven by formaldehyde from RICE.[37] Another facility has a facility-wide risk of 100-in-1 million, with 90 percent of the risk attributed to natural gas transmission and storage. There are 74 facilities with facility-wide MIR of 1-in-1 million or greater. Of these facilities, 10 have natural gas transmission and storage operations that contribute greater than 50 percent to the facility-wide risks. As discussed above, we are proposing MACT standards for benzene emissions from small glycol dehydrators in this action. These standards would reduce the risk from benzene emissions at facilities with natural gas transmission and storage operations. The facility-wide cancer risks at the facilities with risks of 1-in-1 million or more are primarily driven by formaldehyde emissions from RICE, which will be assessed in a future RTR for that category.

The facility-wide maximum individual chronic noncancer TOSHI is estimated to be 80, based on actual emissions. Of the 321 facilities included in this analysis, 30 have facility-wide maximum chronic noncancer TOSHI values greater than 1. Of these facilities, none had natural gas transmission and storage operations that contributed greater than 50 percent to these facility-wide risks. The chronic noncancer risks at these facilities are primarily driven by acrolein emissions from RICE.

iii. Demographic Risk Analysis Results

The results of the demographic analyses performed to investigate the distribution of cancer risks at or above 1-in-1 million among the surrounding population are summarized in Table 7 below. These results, for various demographic groups, are based on actual emissions levels for the population living within 50 km of the facilities.

TABLE 7—NATURAL GAS TRANSMISSION AND STORAGE DEMOGRAPHIC RISK ANALYSIS RESULTS

	Nationwide	Population with cancer risk at or above 1-in-1 million due to . . .	
		Source category HAP emissions	Facility-wide HAP emissions
Total Population	285,000,000	2,500	99,000
Race by Percent			
White	75	92	58
All Other Races	25	8	42
Race by Percent			
White	75	92	58
African American	12	6	40
Native American	0.9	0.1	0.2
Other and Multiracial	12	1	2
Ethnicity by Percent			
Hispanic	14	1	2
Non-Hispanic	86	99	98
Income by Percent			
Below Poverty Level	13	17	20
Above poverty level	87	83	80
Education by Percent			
Over 25 and without High School Diploma	13	20	15
Over 25 and with a High School Diploma	87	80	85

The results of the Natural Gas Transmission and Storage source category demographic analysis indicate that there are approximately 2,500 people exposed to a cancer risk at or above 1-in-1 million due to emissions from the source category, including an estimated 8 percent that are classified as minority (listed as ''All Other Races'' in Table 7 above). Of the 2,500 people with estimated cancer risks at or above 1-in-1 million from the source category, 17 percent are in the ''Below Poverty Level'' demographic group, and 20 percent are in the ''Over 25 and without High School Diploma'' demographic group, results which are 4 and 7 percentage points higher, respectively, than the percentages for these demographic groups across the United States. The percentages for the other demographic groups are lower than their respective nationwide percentages. The table also shows that there are approximately 99,000 people exposed to an estimated cancer risk at or above 1-in-1 million due to facility-wide emissions, including an estimated 42 percent that are classified as minority (''All Other Races'' in Table 7 above). Of the 99,000 people with estimated cancer risk at or above 1-in-1 million from facility-wide emissions, 40 percent are in the ''African American'' demographic group, 20 percent are in the ''Below Poverty Level'' demographic group, and 15 percent are in the ''Over 25 and without High School Diploma'' demographic group, results which are 28, 7 and 2 percentage points higher, respectively, than the percentages for these demographic groups across the United States. The percentages for the other demographic groups are equal to

[37] We note that there is an ongoing IRIS reassessment for formaldehyde, and that future RTR risk assessments will use the cancer potency for formaldehyde that results from that reassessment. As a result, the current results may not match those of future assessments.

or lower than their respective nationwide percentages.

b. What are the proposed risk decisions for the Natural Gas Transmission and Storage source category?

i. Risk Acceptability

In the risk analysis we performed for this source category, pursuant to CAA section 112(f)(2), we considered the available health information—the MIR; the numbers of persons in various risk ranges; cancer incidence; the maximum noncancer HI; the maximum acute noncancer hazard; the extent of noncancer risks; the potential for adverse environmental effects; distribution of risks in the exposed population; and risk estimation uncertainty (54 FR 38044, September 14, 1989).

For the Natural Gas Transmission and Storage source category, the risk analysis we performed indicates that the cancer risks to the individual most exposed could be as high as 90-in-1 million due to actual and allowable emissions (30-in-1 million, based on the lower end of the benzene URE range). These risks are near 100-in-1 million, which is the presumptive limit of acceptability. On the other hand, the risk analysis shows low cancer incidence (1 case in every 1,000 years), low potential for adverse environmental effects or human health multi-pathway effects and that chronic and acute noncancer health impacts are unlikely. We conclude that acute noncancer health impacts are unlikely for reasons similar to those described in section VII.C.2.b.i of this preamble.

Our additional analysis of facility-wide risks showed that, among three facilities with maximum facility-wide cancer risk of 100-in-1 million or greater, one facility has a facility-wide cancer risk of 100-in-1 million, with 90 percent of the risk attributed to natural gas and transmission and storage. There are 30 facilities with a maximum chronic noncancer TOSHI greater than 1, but natural gas transmission and storage operations did not drive this risk.

In determining whether risk is acceptable, we considered the available health information, as described above. In this case, because the MIR is approaching, but still less than 100-in-1 million risk, and because a number of other factors indicate relatively low risk concern (*e.g.,* low cancer incidence, low potential for adverse environmental effects or human health multi-pathway effects, chronic and acute noncancer health impacts unlikely), we are proposing to determine that the risks are acceptable.

ii. Ample Margin of Safety

We next considered whether the existing MACT standard provides an ample margin of safety. In this analysis, we investigated available emissions control options that might reduce the risk associated with emissions from the source category and considered this information, along with all of the health risks and other health information considered in the risk acceptability determination. The estimated MIR of 90-in-1 million discussed above is driven by the 0.9 Mg/year benzene limit compliance alternative for the glycol dehydrator MACT standard in the current NESHAP. Removal of this compliance alternative would lower the MIR for the source category to 20-in-1 million. We, therefore, considered removing this compliance alternative as an option for reducing risk and assessed the cost of such alternative. Without the compliance alternative, affected glycol dehydrators (*i.e.,* those units with annual average benzene emissions of 0.9 Mg/yr or greater and an annual average natural gas throughput of 283,000 scmd or greater) must demonstrate compliance with the 95-percent control requirement, which we believe can be shown with their existing control devices in most cases, although, in some instances, installation of a different or an additional control may be necessary.

In section VII.B.1 above, we discuss the costs for requiring controls on currently unregulated ''small glycol dehydrators,'' which are similar, in operation and type of emission controls, to the dehydrators subject to the current MACT (''large dehydrators''). The HAP cost effectiveness determined for small dehydrators at the floor level of control was $1,650/Mg. Although control methodologies are similar for large and small dehydrators, we expect that the costs for controls on large units could be as much as twice as high as for small units because of the large gas flow being processed. However, we also expect that the amount of HAP emission reduction for the large dehydrators, in general, to be as much as, or more than, the amount achieved by small dehydrators. In light of the above, we do not expect the cost effectiveness of the control device needed to meet the 95-percent control requirement for large dehydrators to exceed $3,300/Mg (*i.e.,* twice the cost effectiveness for small dehydrators), which we consider to be reasonable.

In accordance with the approach established in the Benzene NESHAP, the EPA weighed all health risk measures and information considered in the risk acceptability determination, along with the costs and economic impacts of emissions controls, technological feasibility, uncertainties and other relevant factors in making our ample margin of safety determination. Considering the health risk information and the reasonable cost effectiveness of the option identified, we propose that the existing MACT standards, with the removal of the 0.9 Mg benzene limit compliance option from the glycol dehydrator standards, provide an ample margin of safety to protect public health.

Pursuant to CAA section 112(f)(4), we are proposing that this change (*i.e.,* removal of the 0.9 Mg/yr compliance alternative) apply 90 days after its effective date. We are requesting comment on whether or not there is sufficient time for the large dehydrators that have been relying on this compliance alternative to come into compliance with the 95-percent control requirement or if additional time is needed. See CAA section 112(f)(4)(A).

We recognize that our proposal to remove the one-ton compliance alternative for the 95-percent control glycol dehydrator MACT standard could have negative impacts on some sources that have come to rely on the flexibility this alternative provides. We solicit comment on any such impacts and whether such impacts warrant adding a different compliance alternative that would result in less risk than the 0.9 Mg/yr benzene limit compliance option. If a commenter suggests a different compliance alternative, the commenter should explain, in detail, what that alternative would be, how it would work, and how it would reduce risk.

As described above, we are proposing that the natural gas transmission and storage MACT standards (with the removal of the 0.9 Mg/yr benzene limit compliance option) provide an ample margin of safety to protect public health. We recognize that one facility has a facility-wide cancer risk of 100-in-1 million, with 90 percent of the risk attributed to natural gas transmission and storage. This risk is driven by benzene emissions from glycol dehydrators and is being addressed by our proposed revision to the Natural Gas Transmission and Storage NESHAP (removal of the 0.9 Mg/yr benzene limit compliance option). As previously mentioned, two facilities have facility-wide MIR of 200-in-1 million, driven by formaldehyde from RICE. Emissions from RICE are regulated under another source category and will be assessed under a future RTR for that category.

D. How did we perform the technology review and what are the results and proposed decisions?

1. What was the methodology for the technology review?

Our technology review is focused on the identification and evaluation of ''developments in practices, processes, and control technologies'' since the promulgation of the MACT standards for the two oil and gas source categories. If a review of available information identifies such developments, then we conduct an analysis of the technical feasibility of requiring the implementation of these developments, along with the impacts (costs, emission reductions, risk reductions, etc.). We then make a decision on whether it is necessary to amend the regulation to require these developments.

Based on specific knowledge of each source category, we began by identifying known developments in practices, processes and control technologies. For the purpose of this exercise, we considered any of the following to be a ''development'':

• Any add-on control technology or other equipment that was not identified and considered during MACT development;

• Any improvements in add-on control technology or other equipment (that was identified and considered during MACT development) that could result in significant additional emission reduction;

• Any work practice or operational procedure that was not identified and considered during MACT development; and

• Any process change or pollution prevention alternative that could be broadly applied that was not identified and considered during MACT development.

In addition to looking back at practices, processes or control technologies reviewed at the time we developed the MACT standards, we reviewed a variety of sources of data to aid in our evaluation of whether there were additional practices, processes or controls to consider. One of these sources of data was subsequent air toxics rules. Since the promulgation of the MACT standards for the source categories addressed in this proposal, the EPA has developed air toxics regulations for a number of additional source categories. We reviewed the regulatory requirements and/or technical analyses associated with these subsequent regulatory actions to identify any practices, processes and control technologies considered in these efforts that could possibly be applied to emission sources in the source categories under this current RTR review.

We also consulted the EPA's RBLC. The terms ''RACT,'' ''BACT,'' and ''LAER'' are acronyms for different program requirements under the CAA provisions addressing the NAAQS. Control technologies classified as RACT, BACT or LAER apply to stationary sources depending on whether the source exists or is new and on the size, age and location of the facility. The BACT and LAER (and sometimes RACT) are determined on a case-by-case basis, usually by state or local permitting agencies. The EPA established the RBLC to provide a central database of air pollution technology information (including technologies required in source-specific permits) to promote the sharing of information among permitting agencies and to aid in identifying future possible control technology options that might apply broadly to numerous sources within a category or apply only on a source-by-source basis. The RBLC contains over 5,000 air pollution control permit determinations that can help identify appropriate technologies to mitigate many air pollutant emission streams. We searched this database to determine whether any practices, processes or control technologies are included for the types of processes used for emission sources (*e.g.,* spray booths) in the source categories under consideration in this proposal.

We also consulted information from the Natural Gas STAR program. The Natural Gas STAR program is a flexible, voluntary partnership that encourages oil and natural gas companies to adopt cost effective technologies and practices that improve operational efficiency and reduce pollutant emissions. The program provides the oil and gas industry with information on new techniques and developments to reduce pollutant emissions from the various processes.

2. What are the results and proposed decisions from the technology review?

There are three types of emission sources covered by the two oil and gas NESHAP. These sources and the control technologies (including add-on control devices and process modifications) considered during the development of the MACT standards are: Glycol dehydrators (combustion devices, recovery devices, process modifications), storage vessels with the PFE (combustion devices, recovery devices) and equipment leaks (LDAR programs, specific equipment modifications). Dehydrators are addressed by both 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH, while equipment leaks and storage vessels with the PFE are only covered by subpart HH.

Since the promulgation of 40 CFR part 63, subpart HH, which established MACT standards to address HAP emissions from equipment leaks at gas processing plants, the EPA has developed LDAR programs that are more stringent than what is required in subpart HH. The most prevalent differences between these more stringent programs and subpart HH relate to the frequency of monitoring and the concentration which constitutes a ''leak.'' We do consider these programs to represent a development in practices and evaluated whether to revise the MACT standards for equipment leaks at natural gas processing plants under subpart HH in light of this development.

An analysis was performed above in section VI.B.1 to assess the VOC reduction, costs and other impacts associated with these more stringent LDAR program options at natural gas processing plants. One option considered was to require compliance with 40 CFR part 60, subpart VVa instead of 40 CFR part 60, subpart VV (the current NSPS requirement for equipment leaks of VOC at natural gas processing plants), which changes the leak definition (based on methane) from 10,000 ppm to 500 ppm and requires monitoring of connectors. Because the current leak definition under NESHAP 40 CFR part 63, subpart HH is the same as that in NSPS subpart VV, and the ratio of VOC to HAP is approximately 20 to 1, we expect that the HAP reduction would be 1/20th of the VOC reduction under subpart VVa. The estimated incremental cost for that option was determined to be $3,340 per ton of VOC. Based on the 20-to-1 ratio, we estimate the incremental cost to control HAP at the subpart VVa level would be approximately $66,800 per ton of HAP ($73,480/Mg). Other options considered in section VI.B.1 of this preamble (and the incremental cost of each option for reducing HAP) are as follows: The use of an optical gas imaging camera monthly with an annual EPA Method 21 check ($129,000 per ton of HAP/$143,600 per Mg, if purchasing the camera; $93,000 per ton of HAP/ $103,300 per Mg, if renting the camera); monthly optical gas imagining alone; and annual optical gas imaging.[38] In

[38] As stated above in section VI.B.1, emissions for the two options using the optical gas imaging camera alone cannot be quantified and, therefore, no cost effectiveness values were determined.

light of the above, we do not believe that the additional costs of these programs are justified.

In addition to the plant-wide evaluations, a component analysis was also evaluated at gas processing plants for the 40 CFR part 60, subpart VVa-level of control (option 1 considered in section VI.B.1).[39] That assessment shows that the subpart VVa-level of control for connectors has an incremental cost effectiveness of $4,360 per ton for VOC for connectors and $144 per ton for VOC for valves. This means the incremental cost to control HAP would be approximately $87,200 per ton ($96,900/Mg) for connectors and $2,880 per ton ($3,200/Mg) for valves. We do not believe the additional cost for the more stringent requirement for connectors is justified, but the additional cost for valves is justified. Therefore, we are proposing to revise the equipment leak requirements in 40 CFR part 63, subpart HH to lower the leak definition for valves to an instrument reading of at least 500 ppm as a result of our technology review.

Some of the practices, processes or control technologies listed by the Natural Gas STAR program applicable to the emission sources in these categories were not identified and evaluated during the original MACT development. While the Natural Gas STAR program does contain information regarding new innovative techniques that are available to reduce HAP emissions, they are not considered to have emission reductions higher than what is set by the original MACT. One control technology identified in the Natural Gas STAR program that would result in no HAP emissions from glycol dehydration units would be the replacement of a glycol dehydration unit with a desiccant dehydrator. This technology cannot be used for natural gas operations with gas streams having high temperature, high volume, and low pressure. Due to the limitations posed by these conditions, we do not consider desiccant dehydrators as MACT.

For storage vessels, the applicable technologies identified by the Gas STAR program, which are evaluated above for proposal under NSPS in section VI.B.4, are similar to the cover and control technologies currently required for storage vessels under the existing MACT. Therefore, these technologies would not result in any further emissions reductions than what is achieved by the original MACT.

[39] Because optical gas imaging is used to view several pieces of equipment at a facility at once to survey for leaks, options involving imaging are not amenable to a component by component analysis.

Our review of the RBLC did not identify any practices, processes and control technologies applicable to the emission sources in these categories that were not identified and evaluated during the original MACT development. In light of the above, we are not proposing any revisions to the existing MACT standards for storage vessels pursuant to section 112(d)(6) of the CAA.

E. What other actions are we proposing?

1. Combustion Control Device Testing

As explained below in section VII.E.2, under our proposal, performance testing would be required initially and every 5 years for non-condenser control devices. However, for certain enclosed combustion control devices, we are proposing to allow, as an alternative to on-site testing, a performance test conducted by a control device manufacturer in accordance with the procedures provided in this proposal. We propose to allow a unit whose model meets the proposed performance criteria to claim a BTEX or HAP destruction efficiency of 98 percent at the facility. This value is lower than the 99.9-percent destruction efficiency required in the manufacturers' test due to variations between the test fuel specified and the gas streams combusted at the actual facility. A source subject to the small dehydrator BTEX limit would use the 98-percent destruction efficiency to calculate their dehydrator's BTEX emissions for the purpose of demonstrating compliance. For the 95-percent control MACT standard, a control device matching the tested model would be considered to meet that requirement. Once a device has been demonstrated to meet the proposed performance criteria (and, therefore, is assigned a 98-percent destruction efficiency), installation of a unit matching the tested model at a facility would require no further performance testing (*i.e.,* periodic tests would not be required every 5 years).

We are proposing this alternative to minimize issues associated with performance testing of certain combustion control devices. We believe that testing units that are not configured with a distinct combustion chamber present several technical issues that are more optimally addressed through manufacturer testing, and once these units are installed at a facility, through periodic inspection and maintenance in accordance with manufacturers' recommendations. One issue is that an extension above certain existing combustion control device enclosures will be necessary to get adequate clearance above the flame zone. Such extensions can more easily be configured by the manufacturer of the control device rather than having to modify an extension in the field to fit devices at every site. Issues related to transporting, installing and supporting the extension in the field are also eliminated through manufacturer testing. Another concern is that the pitot tube used to measure flow can be altered by radiant heat from the flame such that gas flow rates are not accurate. This issue is best overcome by having the manufacturer select and use the pitot tube best suited to their specific unit. For these reasons, we believe the manufacturers' test is appropriate for these control devices with ongoing performance ensured by periodic inspection and maintenance.

This proposed alternative does not apply to flares, as defined in 40 CFR 63.761 and 40 CFR 63.1271, which must demonstrate compliance by meeting the design and operation requirements in 40 CFR 63.11(b), 40 CFR 63.772(e)(2) and 40 CFR 63.1282(d)(2). It also would not apply to thermal oxidizers having a combustion chamber/firebox where combustion temperature and residence time can be measured during an on-site performance test and are valid indicators of performance. These thermal oxidizers do not present the issues described above relative to on-site performance testing and, therefore, do not need an alternative testing option. The proposed alternative would, therefore, apply to enclosed combustion control devices except for these thermal oxidizers.

In conjunction with the proposed manufacturer testing alternative, we are proposing to add a definition for flare to clarify that flares, as referenced in the NESHAP (and to which the proposed testing alternative does not apply), refers to a thermal oxidation system with an open flame (*i.e.,* without enclosure). Accordingly, any thermal oxidation system that does not meet the proposed flare definition would be considered an enclosed combustion control device.

We estimate that there are many existing facilities currently using enclosed combustion control devices that would be required to either conduct an on-site performance test or install and operate a control device tested by the manufacturer under our proposal. Given the estimated number of these combustion control devices in use, the time required for manufacturers to test and manufacture such units, we are proposing that existing sources have up to 3 years from the date of the final rules' publication date to comply with the initial performance testing requirements.

2. Monitoring, Recordkeeping and Reporting

We are proposing to make changes to the monitoring requirements described below to address issues we have identified through a monitoring sufficiency review performed during the RTR process. First, we are including calibration procedures associated with parametric monitoring requirements in the existing NESHAP. The NESHAP require parametric monitoring of control device parameters (*e.g.,* temperatures or flowrate monitoring), but did not include information on calibration or included inadequate information on calibration of monitoring devices. Therefore, we are specifying the calibration requirements for temperature and flow monitors that the NESHAP currently lacks.

In addition, under the current NESHAP, a design analysis can be used in lieu of performance testing to demonstrate compliance and establish operating parameter limits. We are proposing to allow the use of the design evaluation alternative only when the control device being used is a condenser. The design evaluation option is appropriate for condensers because their emissions can be accurately predicted using readily available physical property information (*e.g.,* vapor pressure data and condensation calculations). In those cases, one would not need to conduct emissions testing to determine actual emissions to demonstrate compliance with the MACT standard. For example, a requirement that ''the temperature at the outlet of the condenser shall be maintained at 50° Fahrenheit below the condensation temperature calculated for the compound of interest using the reference equation'' (*e.g.,* National Institute of Standards and Technology Chemistry WebBook at *http://webbook.nist.gov/chemistry/*) is adequate to assure proper operation of the condenser and, therefore, compliance with the required emission standard.

For other types of control technologies, such as carbon adsorption systems and enclosed combustion devices,[40] the ability to predict emissions depends on data developed by the vendor and such data may not reliably result in an accurate prediction of emissions from a specific facility. There are variables (*e.g.,* air to fuel ratios and waste constituents for combustion; varying organic concentrations, constituents and capacity issues, including break-through for carbon adsorption) that make theoretical predictions less reliable. The effects of these site-specific variables on emissions are not easily predictable and establishing monitoring conditions (*e.g.,* combustion temperature, vacuum regeneration) based on vendor data will likely not account for those variables. Therefore, we propose to eliminate the design evaluation alternative for non-condenser controls.

For non-condenser controls (and condensers not using the design analysis option), in addition to the initial compliance testing, we are proposing that performance tests be conducted at least once every 5 years and whenever sources desire to establish new operating limits. Under the current NESHAP, a performance test is only conducted in two instances: (1) As an alternative to a design analysis for their compliance demonstration and identification of operating parameter ranges and (2) as a requirement to resolve a disagreement between the EPA and the owner or operator regarding the design analysis. The current NESHAP do not require additional performance testing beyond these two cases (*i.e.,* there is no periodic testing requirement). As mentioned above, we are proposing to remove the design evaluation option for non-condenser controls. For non-condenser controls (and condensers not using the design analysis option), the proposed periodic testing would ensure compliance with the emission standards by verifying that the control device is meeting the necessary HAP destruction efficiency determined in the initial performance test. As discussed above in section VII.E.1, we are proposing that combustion control devices tested under the manufacturers' procedure are not required to conduct periodic testing. In addition, we are also proposing that combustion control devices that can demonstrate a uniform combustion zone temperature meeting the required control efficiency during the initial performance test are exempt from periodic testing. The requirement for continuous monitoring of combustion zone temperature is an accurate indicator of control device performance and eliminates the need for future testing.

The current NESHAP (40 CFR 63.771(d) and 40 CFR 63.1281(d)) require operating an enclosed combustion device at a minimum residence time of 0.5 seconds at a minimum temperature of 760 degrees Celsius. We are proposing to remove the residence time requirement. The residence time requirement is not needed because the compliance demonstration made during the performance test is sufficient to ensure that the combustion device has adequate residence time to ensure the needed destruction efficiency. Therefore, we are proposing to remove the residence time requirement.

We are also clarifying at 40 CFR 63.773(d)(3)(i) and 40 CFR 63.1283(d)(3)(i) for thermal vapor incinerators, boilers and process heaters, that the temperature sensor shall be installed at a location representative of the combustion zone temperature. Currently, the regulation requires that the temperature sensor be installed at a location ''downstream of the combustion zone'' because we had thought that the temperature downstream would be representative of combustion zone temperature. We have now learned that may or may not be the case. We are, therefore, proposing to amend this provision to more accurately reflect the intended requirement.

Next, consistent with revisions for SSM, we've revised 40 CFR 63.771(d)(4)(i) and 40 CFR 63.1281(d)(4)(i), except when maintenance or repair on a unit cannot be completed without a shutdown of the control device.

Also, we've updated the criteria for prior performance test results that can be used to demonstrate compliance in lieu of conducting a performance test. These updates ensure that data for determining compliance are accurate, up-to-date, and truly representative of actual operating conditions.

In addition, we are proposing to revise the temperature monitoring device minimum accuracy criteria in 40 CFR 63.773(d)(3)(i) to better reflect the level of performance that is required of the temperature monitoring devices. We believe that temperature monitoring devices currently used to meet the requirements of the NESHAP can meet the proposed revised criteria without modification.

Also, we are proposing to revise the calibration gas concentration for the no detectable emissions procedure applicable to closed vent systems in 40 CFR 63.772(c)(4)(ii) from 10,000 ppmv to 500 ppmv methane to be consistent with the leak threshold of 500 ppmv in 40 CFR part 63, subpart HH. The current calibration level is inconsistent with achieving accurate readings at the level necessary to demonstrate there are no detectable emissions.

[40] The design analysis alternative in the existing MACT does not apply to flares. As previously mentioned, the existing MACT provides separate design and operation requirements for flares.

Also, we are proposing recordkeeping and reporting requirements for carbon adsorption systems. The current NESHAP require the replacement of all carbon in the carbon adsorption system with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon system, but provide no recordkeeping or reporting requirement to document and assure compliance with this standard. We believe that maintaining some sort of log book is a reasonable alternative combined with a requirement to report instances when specified practices are not followed. Therefore, the proposed rule adds reporting and recordkeeping requirements for establishing a schedule and maintaining logs of carbon replacement.

Finally, as noted above in section VII.B.1, we are proposing a BTEX emissions limit for small glycol dehydration unit process vents. For the compliance demonstration, we propose that parametric monitoring of the control device be performed. We believe that parametric monitoring is adequate for glycol dehydrators in these two source categories because temperature monitoring, whether it be to verify proper condenser or combustion device operation, is a reliable indicator of performance for reducing organic HAP emissions. We also considered the use of a continuous emissions monitoring system (CEMS) to monitor compliance. However, for glycol dehydrators in the oil and natural gas sector, the necessary electricity, weather-protective enclosures and daily staffing are not usually available. We, therefore, question the technical feasibility of operating a CEMS correctly in this sector. We request comment on the practicality of including provisions in the final rule for a CEMS to monitor BTEX emissions for small glycol dehydration units.

3. Startup, Shutdown, Malfunction

The United States Court of Appeals for the District of Columbia Circuit vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), *cert. denied, 130 S. Ct. 1735 (U.S. 2010).* Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), that is part of a regulation, commonly referred to as the *General Provisions Rule,* that the EPA promulgated under section 112 of the CAA. When incorporated into CAA section 112(d) regulations for specific source categories, these two provisions exempt sources from the requirement to comply with the otherwise applicable CAA section 112(d) emission standard during periods of SSM.

We are proposing the elimination of the SSM exemption in the two oil and gas NESHAP. Consistent with *Sierra Club* v. *EPA,* the EPA is proposing to apply the standards in these NESHAP at all times. In addition, we are proposing to revise 40 CFR 63.771(d)(4)(i) and 40 CFR 63.1281(d)(4)(i) to remove the provision allowing shutdown of the control device during maintenance or repair. We are also proposing several revisions to the General Provisions applicability table for the MACT standard. For example, we are proposing to eliminate the incorporation of the General Provisions' requirement that the source develop a SSM plan. We are also proposing to eliminate or revise certain recordkeeping and reporting requirements related to the SSM exemption. The EPA has attempted to ensure that we have not included in the proposed regulatory language any provisions that are inappropriate, unnecessary or redundant in the absence of the SSM exemption. We are specifically seeking comment on whether there are any such provisions that we have inadvertently incorporated or overlooked.

In proposing the MACT standards in these rules, the EPA has taken into account startup and shutdown periods. We believe that operations and emissions do not differ from normal operations during these periods such that it warrants a separate standard. Therefore, we have not proposed different standards for these periods.

Periods of startup, normal operations and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a ''sudden, infrequent and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *'' (40 CFR 63.2). The EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times. In *Mossville Environmental Action Now* v. *EPA,* 370 F.3d 1232, 1242 (D.C. Cir. 2004), the Court upheld as reasonable, standards that had factored in variability of emissions under all operating conditions. However, nothing in CAA section 112(d) or in case law requires that the EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. See *Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978), (''In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by ''uncontrollable acts of third parties,'' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.'').

Further, it is reasonable to interpret CAA section 112(d) as not requiring the EPA to account for malfunctions in setting emissions standards. For example, we note that CAA section 112 uses the concept of ''best performing'' sources in defining MACT, the level of stringency that major source standards must meet. Applying the concept of ''best performing'' to a source that is malfunctioning presents significant difficulties. The goal of best performing sources is to operate in such a way as to avoid malfunctions of their units.

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 112(d) standards for oil and natural gas production facility and natural gas transmission and storage operations. As noted above, by definition, malfunctions are sudden and unexpected events, and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in each source category. Moreover, malfunctions can also vary in frequency, degree and duration, further complicating standard setting.

In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, ''sudden, infrequent, not reasonably preventable'' and was not instead ''caused in part by poor maintenance or careless operation.'' 40 CFR 63.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause or contribute to an exceedance of the relevant emission standard. (See, *e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown* (September 20, 1999); *Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions* (February 15, 1983)). The EPA is, therefore, proposing to add to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions in both of the MACT standards addressed in this proposal. See 40 CFR 63.761 for sources subject to the oil and natural gas production MACT standards, or 40 CFR 63.1271 for sources subject to the natural gas transmission and storage MACT standards (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also are proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; a source subject to the oil and natural gas production facilities or natural gas transmission MACT standards must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 63.762 and a source subject to the natural gas transmission and storage facilities MACT standards must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 63.1272. (See 40 CFR 22.24.) The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of evidence that excess emissions ''[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *.'' The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 63.762 for sources subject to the oil and natural gas production facilities MACT standards or 40 CFR 63.1272 for sources subject to the natural gas transmission and storage facilities MACT standards and to prevent future malfunctions. For example, the source must prove by a preponderance of evidence that ''[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *'' and that ''[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *.'' In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with section 113 of the CAA (see also 40 CFR 22.77).

4. Applicability and Compliance

a. Calculating Potential To Emit (PTE)

We are proposing to amend section 40 CFR 63.760(a)(1)(iii) to clarify that sources must use a glycol circulation rate consistent with the definition of PTE in 40 CFR 63.2 in calculating emissions for purposes of determining PTE. Affected parties have misinterpreted the current language concerning measured values or annual average to apply to a broader range of parameters than was intended. Those qualifiers were meant to apply to gas characteristics that are measured, such as inlet gas composition, pressure and temperature rather than process equipment settings. That means that the circulation rate used in PTE determinations shall be the maximum under its physical and operational design.

In addition to the proposed changes described above, we are seeking comment on several PTE related issues. According to the data available to the Administrator, when 40 CFR part 63, subpart HH was promulgated, the level of HAP emissions was predominantly driven by natural gas throughput (*i.e.,* HAP emissions went up or down in concert with natural gas throughput). Since promulgation, we have learned that there is not always a direct correlation between HAP emissions and natural gas throughput. We have received information suggesting that, in some cases, HAP emissions can increase despite decreasing natural gas throughput due to changes in gas composition. We are asking for comment regarding the likelihood of this occurrence and data demonstrating the circumstances where it occurs. In light of the potential issue, we are asking for comment regarding the addition of provisions in the NESHAP to require area sources to recalculate their PTE to confirm that they are indeed area sources and whether that calculation should be performed on an annual or biannual basis to verify that changes in gas composition have not increased their emissions.

b. Definition of Facility and Applicability Criteria

Subpart HH of 40 CFR part 63 (section 63.760(a)(2)) currently defines facilities as those where hydrocarbon liquids are processed, upgraded or stored prior to the point of custody transfer or where natural gas is processed, upgraded or stored prior to entering the Natural Gas Transmission and Storage source category. We are proposing to remove the references to ''point of custody transfer'' and ''transmission and storage source categories'' from the definition because the operations performed at a site sufficiently define a facility and the scope of the subpart is specified already under 40 CFR 63.760. In addition, we are removing the custody transfer reference from the applicability criteria in 40 CFR 63.760(a)(2). Since hydrocarbon liquids can pass through several custody transfer points between the well and the final destination, the custody transfer criteria is not clear enough. We are, therefore, proposing to replace the reference to ''point of custody transfer'' with a more specific description of the point up to which the subpart applies (*i.e.,* the point where hydrocarbon liquids enter either the organic liquids distribution or petroleum refineries source categories) and exclude custody transfer from that criteria. We believe this change eliminates ambiguity and is consistent with the oil and natural gas production-specific provisions in the organic liquids distribution MACT.

5. Other Proposed Changes To Clarify These Rules

The following lists additional changes to the NESHAP we are proposing. This list includes proposed rule changes that address editorial corrections and plain language revisions:

- Revise 40 CFR 63.769(b) to clarify that the equipment leak provisions in 40 CFR part 63, subpart HH do not apply to a source if that source is required to control equipment leaks under either 40 CFR part 63, subpart H or 40 CFR part 60, subpart KKK. The current 40 CFR 63.769(b), which states that subpart HH does not apply if a source meets the requirements in either of the subparts mentioned above, does not clearly express our intent that such source must be implementing the LDAR provisions in the other 40 CFR part 60 or 40 CFR part 63 subparts to qualify for the exemption.

• Revise 40 CFR 63.760(a)(1) to clarify that an existing area source that increases its emissions to major source levels has up to the first substantive compliance date to either reduce its emissions below major source levels by obtaining a practically enforceable permit or comply with the applicable major source provisions of 40 CFR part 63, subpart HH. We have revised the second to last sentence in 40 CFR 63.760(a)(1) by removing the parenthetical statement because it simply reiterates the last sentence of this section and is, therefore, unnecessary.

• Revise 40 CFR 63.771(d)(1)(ii) and 40 CFR 63.1281(d)(1)(ii) to clarify that the vapor recovery device and ''other control device'' described in those provisions refer to non-destructive control devices only.

• Revise the last sentence of 40 CFR 63.764(i) and 40 CFR 63.1274(g) to clarify the requirements following an unsuccessful attempt to repair a leak.

• Updated the e-mail and physical address for area source reporting in 40 CFR 63.775(c)(1).

VIII. What are the cost, environmental, energy and economic impacts of the proposed 40 CFR part 60, subpart OOOO and amendments to subparts HH and HHH of 40 CFR part 63?

We are presenting a combined discussion of the estimates of the impacts for the proposed 40 CFR part 60, subpart OOOO and proposed amendments to 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH. The cost, environmental and economic impacts presented in this section are expressed as incremental differences between the impacts of an oil and natural gas facility complying with the amendments to subparts HH and HHH and new standards under 40 CFR 60, subpart OOOO and the baseline, *i.e.,* the standards before these amendments. The impacts are presented for the year 2015, which will be the year that all existing oil and natural gas facilities will have to be in compliance, and also the year that will represent approximately 5 years of construction of new oil and natural gas facilities subject to the NSPS emissions limits. The analyses and the documents referenced below can be found in Docket ID Numbers EPA–HQ–OAR–2007–0877 and EPA–HQ–OAR–2002–0051.

A. What are the affected sources?

We expect that by 2015, the year when all existing sources will be required to come into compliance in the United States, there will be 97 oil and natural gas production facilities and 15 natural gas transmission and storage facilities with one or more existing glycol dehydration units. We also estimate that there will be an additional 329 (there are 47 facilities that already have an affected glycol dehydration unit) existing oil and natural gas production facilities with existing storage vessels that we expect to be affected by these final amendments. These facilities operate approximately 134 glycol dehydration units (115 in production and 19 in transmission and storage) and 1,970 storage vessels. Approximately 10 oil and natural gas production and two transmission and storage facilities would have new glycol dehydration units and 38 production facilities would have new dehydration units. We expect new production facilities would operate approximately 12 production glycol dehydration units and 197 storage vessels and new transmission and storage would operate approximately two glycol dehydration units.

Based on data provided by the United States Energy Information Administration, we anticipate that by 2015 there will be approximately 21,800 gas wellhead facilities, 790 reciprocating compressors, 30 centrifugal compressors, 14,000 pneumatic devices and 300 storage vessels subject to the new NSPS for VOC. Some of these affected facilities will be built at existing facilities and some at new greenfield facilities. Based on data limitations, we assume impacts are equal regardless of location.

There are about 21 glycol dehydration units with high enough HAP emissions that we believe cannot meet the emissions limit without using more than one control technique. In developing the cost impacts, we assume that they would require multiple controls. The controls for which we have detailed cost data are condensers and VRU, so we developed costs for both controls to develop what we consider to be a reasonable cost estimate for these facilities. This does not imply that we believe these facilities will specifically use a combination of a condenser and vapor recovery limit, but we do believe the combination of these control results is a reasonable estimate of cost.

B. How are the impacts for this proposal evaluated?

For these proposed Oil and Natural Gas Production and Natural Gas Transmission and Storage NESHAP amendments and NSPS, the EPA used two models to evaluate the impacts of the regulation on the industry and the economy. Typically, in a regulatory analysis, the EPA determines the regulatory options suitable to meet statutory obligations under the CAA. Based on the stringency of those options, the EPA then determines the control technologies and monitoring requirements that sources might rationally select to comply with the regulation. This analysis is documented in an engineering analysis. The selected control technologies and monitoring requirements are then evaluated in a cost model to determine the total annualized control costs. The annualized control costs serve as inputs to an Economic Impact Analysis model that evaluates the impacts of those costs on the industry and society as a whole.

The Economic Impact Analysis used the National Energy Modeling System (NEMS) to estimate the impacts of the proposed NSPS on the United States energy system. The NEMS is a publically-available model of the United States energy economy developed and maintained by the Energy Information Administration of the United States DOE and is used to produce the *Annual Energy Outlook,* a reference publication that provides detailed forecasts of the energy economy from the current year to 2035. The impacts we estimated included changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas and changes in international trade of crude oil and natural gas. We evaluated whether and to what extent the increased production costs imposed by the NSPS might alter the mix of fuels consumed at a national level. Additionally, we combined estimated emissions co-reductions of methane from the engineering analysis with NEMS analysis to estimate the net change in CO_2e GHG from energy-related sources.

C. What are the air quality impacts?

For the oil and natural gas sector NESHAP and NSPS, we estimated the emission reductions that will occur due to the implementation of the final emission limits. The EPA estimated emission reductions based on the control technologies selected by the engineering analysis. These emission reductions associated with the proposed amendments to 40 CFR part 63, subpart

HH and 40 CFR part 63, subpart HHH are based on the estimated population in 2008. Under the proposed limits for glycol dehydration units and storage vessels, we have estimated that the HAP emissions reductions will be 1,400 tpy for existing units subject to the proposed emissions limits.

For the NSPS, we estimated the emission reductions that will occur due to the implementation of the final emission limits. The EPA estimated emission reductions based on the control technologies selected by the engineering analysis. These emission reductions are based on the estimated population in 2015. Under the proposed NSPS, we have estimated that the emissions reductions will be 540,000 tpy VOC for affected facilities subject to the NSPS.

The control strategies likely adopted to meet the proposed NESHAP amendments and the proposed NSPS will result in concurrent control of HAP, methane and VOC emissions. We estimate that direct reductions in HAP, methane and VOC for the proposed rules combined total about 38,000 tpy, 3.4 million tpy and 540,000 tpy, respectively.

Under the final standards, new monitoring requirements are being added.

D. What are the water quality and solid waste impacts?

We estimated minimal water quality impacts for the proposed amendments and proposed NSPS. For the proposed amendments to the NESHAP, we anticipate that the water impacts associated with the installation of a condenser system for the glycol dehydration unit process vent would be minimal. This is because the condensed water collected with the hydrocarbon condensate can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with produced water for disposal, usually by reinjection.

Similarly, the water impacts associated with installation of a vapor control system either on a glycol dehydration unit or a storage vessel would be minimal. This is because the water vapor collected along with the hydrocarbon vapors in the vapor collection and redirect system can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with the produced water for disposal for reinjection.

There would be no water impacts expected for facilities subject to the proposed NSPS. Further, we do not anticipate any adverse solid waste impacts from the implementation of the proposed NESHAP amendments and the proposed NSPS.

E. What are the secondary impacts?

Indirect or secondary air quality impacts include impacts that will result from the increased electricity usage associated with the operation of control devices, as well as water quality and solid waste impacts (which were just discussed) that might occur as a result of these proposed actions. We estimate the proposed amendments to 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH will increase emissions of criteria pollutants due to the potential use of flares for the control of storage vessels. We do not estimate an increased energy demand associated with the installation of condensers, VRU or flares. The increases in criteria pollutant emissions associated with the use of flares to control storage vessels subject to existing source standards are estimated to be 5,500 tpy of CO_2, 16 tpy of carbon monoxide (CO), 3 tpy of NO_X, less than 1 tpy of particulate matter (PM) and 6 tpy total hydrocarbons. For storage vessels subject to new source standards, increases in secondary air pollutants are estimated to be less than 900 tpy of CO_2, 3 tpy of CO, 1 tpy of NO_X, 1 tpy of PM and 1 tpy total hydrocarbons.

In addition, we estimate that the secondary impacts associated with the pneumatic controller requirements to comply with the proposed NSPS would be about 22 tpy of CO_2, 1 tpy of NO_X and 3 tpy PM. For gas wellhead affected facilities, we estimate that the use of flares would result in increases in criteria pollutant emissions of about 990,000 tons of CO_2, 2,800 tpy of CO, 500 tpy of NO_X, 5 tpy of PM and 1,000 tpy total hydrocarbons.

F. What are the energy impacts?

Energy impacts in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section. There would be little national energy demand increase from the operation of any of the control options analyzed under the proposed NESHAP amendments and proposed NSPS.

The proposed NESHAP amendments and proposed NSPS encourage the use of emission controls that recover hydrocarbon products, such as methane and condensate that can be used on-site as fuel or reprocessed within the production process for sale. We estimated that the proposed standards will result in a net cost savings due to the recovery of salable natural gas and condensate. Thus, the final standards have a positive impact associated with the recovery of non-renewable energy resources.

G. What are the cost impacts?

The estimated total capital cost to comply with the proposed amendments to 40 CFR part 63, subpart HH for major sources in the Oil and Natural Gas Production source category is approximately $51.5 million. The total capital cost for the proposed amendments to 40 CFR part 63, subpart HHH for major sources in the Natural Gas Transmission and Storage source category is estimated to be approximately $370 thousand. All costs are in 2008 dollars.

The total estimated net annual cost to industry to comply with the proposed amendments to 40 CFR part 63, subpart HH for major sources in the Oil and Natural Gas Production source category is approximately $16 million. The total net annual cost for proposed amendments to 40 CFR part 63, subpart HHH for major sources in the Natural Gas Transmission and Storage source category is estimated to be approximately $360,000. These estimated annual costs include: (1) The cost of capital, (2) operating and maintenance costs, (3) the cost of monitoring, inspection, recordkeeping and reporting (MIRR) and (4) any associated product recovery credits. All costs are in 2008 dollars.

The estimated total capital cost to comply with the proposed NSPS is approximately $740 million in 2008 dollars. The total estimated net annual cost to industry to comply with the proposed NSPS is approximately $740 million in 2008 dollars. This annual cost estimate includes: (1) The cost of capital, (2) operating and maintenance costs and (3) the cost of MIRR. This estimated annual cost does not take into account any producer revenues associated with the recovery of salable natural gas and hydrocarbon condensates.

When revenues from additional product recovery are considered, the proposed NSPS is estimated to result in a net annual engineering cost savings overall. When including the additional natural gas recovery in the engineering cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. The engineering analysis cost analysis assumes the value of recovered condensate is $70 per barrel. Based on the engineering analysis, about 180,000,000 Mcf (180 billion cubic feet) of natural gas and 730,000 barrels of condensate are estimated to be recovered by control requirements in 2015. Using the price assumptions, the estimated revenues from natural gas product recovery are approximately $780 million in 2008 dollars. This savings is estimated at $45 million in 2008 dollars.

Using the engineering cost estimates, estimated natural gas product recovery, and natural gas product price assumptions, the net annual engineering cost savings is estimated for the proposed NSPS at about $45 million in 2008 dollars. Totals may not sum due to independent rounding.

As the price assumption is very influential on estimated annualized engineering costs, we performed a simple sensitivity analysis of the influence of the assumed wellhead price paid to natural gas producers on the overall engineering annualized costs estimate of the proposed NSPS. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook in 2008 dollars, the annualized costs are estimated at about −$90 million, which would approximately double the estimate of net cost savings of the proposed NSPS. As indicated by this difference, EPA has chosen a relatively conservative assumption (leading to an estimate of few savings and higher net costs) for the engineering costs analysis. The natural gas price at which the proposed NSPS breaks-even from an estimated engineering costs perspective is around $3.77/Mcf. A $1/Mcf change in the wellhead natural gas price leads to about a $180 million change in the annualized engineering costs of the proposed NSPS. Consequently, annualized engineering costs estimates would increase to about $140 million under a $3/Mcf price or decrease to about −$230 million under a $5/Mcf price. For further details on this sensitivity analysis, please refer the regulatory impact analysis (RIA) for this rulemaking located in the docket.

H. What are the economic impacts?

The NEMS analysis of energy system impacts for the proposed NSPS option estimates that domestic natural gas production is likely to increase slightly (about 20 billion cubic feet or 0.1 percent) and average natural gas prices to decrease slightly ($0.04 per Mcf in 2008 dollars or 0.9 percent at the wellhead for onshore producers in the lower 48 states) for 2015, the year of analysis. This increase in production and decrease in wellhead price is largely a result of the increased natural gas and condensate recovery as a result of complying with the NSPS. Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly ($0.02/barrel in 2008 dollars or less than 0.1 percent at the wellhead for onshore producers in the lower 48 states) in the year of analysis, 2015. The NEMS-based analysis estimates in the year of analysis, 2015, that net imports of natural gas and crude will not change significantly.

Total CO_2e emissions from energy-related sources are expected to increase about 2.0 million metric tons CO_2e or 0.04 percent under the proposed NSPS, according to the NEMS analysis. This increase is attributable largely to natural gas consumption increases. This estimate does not include CO_2e reductions from the implementation of the controls; these reductions are discussed in more detail in the benefits section that follows.

We did not estimate the energy economy impacts of the proposed NESHAP amendments using NEMS, as the expected costs of the rule are not likely to have estimable impacts on the national energy economy.

I. What are the benefits?

The proposed Oil and Natural Gas NSPS and NESHAP amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of the industry. These proposed rules combined are anticipated to reduce 38,000 tons of HAP, 540,000 tons of VOC and 3.4 million tons of methane. These pollutants are associated with substantial health effects, welfare effects and climate effects. With the data available, we are not able to provide credible health benefit estimates for the reduction in exposure to HAP, ozone and PM (2.5 microns and less) ($PM_{2.5}$) for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and VOC reductions.

This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects and climate effects, as well as additional product recovery.

Although we do not have sufficient information or modeling available to provide quantitative estimates for this rulemaking, we include a qualitative assessment of the health effects associated with exposure to HAP, ozone and $PM_{2.5}$ in the RIA for this rule. These qualitative effects are briefly summarized below, but for more detailed information, please refer to the RIA, which is available in the docket. One of the HAP of concern from the oil and natural gas sector is benzene, which is a known human carcinogen, and formaldehyde, which is a probable human carcinogen. VOC emissions are precursors to both $PM_{2.5}$ and ozone formation. As documented in previous analyses (U.S. EPA, 2006 [41] and U.S. EPA, 2010 [42]), exposure to $PM_{2.5}$ and ozone is associated with significant public health effects. $PM_{2.5}$ is associated with health effects such as premature mortality for adults and infants, cardiovascular morbidity, such as heart attacks, hospital admissions and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital and emergency room visits, work loss days, restricted activity days and respiratory symptoms, as well as visibility impairment.[43] Ozone is associated with health effects such as respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days and premature mortality, as well as injury to vegetation and climate effects.[44]

In addition to the improvements in air quality and resulting benefits to human health and non-climate welfare effects previously discussed, this proposed rule is expected to result in significant climate co-benefits due to anticipated methane reductions. Methane is a potent GHG that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. According to the

[41] U.S. EPA. RIA. *National Ambient Air Quality Standards for Particulate Matter,* Chapter 5. Office of Air Quality Planning and Standards, Research Triangle Park, NC. October 2006. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/Chapter%205-Benefits.pdf*.

[42] U.S. EPA. RIA. *National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2010. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/s1-supplemental_analysis_full.pdf.*

[43] U.S. EPA. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December 2009. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546*.

[44] U.S. EPA. *Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final).* EPA/600/R–05/004aF–cF. Washington, DC: U.S. EPA. February 2006. Available on the Internet at *http://cfpub.epa.gov/ncea/CFM/recordisplay.cfm?deid=149923.*

Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (2007), methane is the second leading long-lived climate forcer after CO_2 globally. Total methane emissions from the oil and gas industry represent about 40 percent of the total methane emissions from all sources and account for about 5 percent of all CO_2e emissions in the United States, with natural gas systems being the single largest contributor to United States anthropogenic methane emissions.[45] Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which, over time, leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity and sea level rise, among other impacts.

This rulemaking proposes emission control technologies and regulatory alternatives that will significantly decrease methane emissions from the oil and natural gas sector in the United States. The regulatory alternatives proposed for the NESHAP and the NSPS are expected to reduce methane emissions annually by about 3.4 million short tons or 65 million metric tons CO_2e. After considering the secondary impacts of this proposal previously discussed, such as increased CO_2 emissions from well completion combustion and decreased CO_2e emissions because of fuel-switching by consumers, the methane reductions become about 62 million metric tons CO_2e. These reductions represent about 26 percent of the baseline methane emissions for this sector reported in the EPA's U.S. Greenhouse Gas Inventory Report for 2009 (251.55 million metric tons CO_2e when petroleum refineries and petroleum transportation are excluded because these sources are not examined in this proposal). After considering the secondary impacts of this proposal, such as increased CO_2 emissions from well completion combustion and decreased CO_2 emissions because of fuel-switching by consumers, the CO_2e GHG reductions are reduced to about 62 million metric tons CO_2e. However, it is important to note that the emission reductions are based upon predicted activities in 2015; the EPA did not forecast sector-level emissions in 2015 for this rulemaking. These emission reductions equate to the climate benefits of taking approximately 11 million typical passenger cars off the road or eliminating electricity use from about 7 million typical homes each year.[46]

The EPA recognizes that the methane reductions proposed in this rule will provide for significant economic climate benefits to society just described. However, there is no interagency-accepted methodology to place monetary values on these benefits. A 'global warming potential (GWP) approach' of converting methane to CO_2e using the GWP of methane provides an approximation method for estimating the monetized value of the methane reductions anticipated from this rule. This calculation uses the GWP of the non-CO_2 gas to estimate CO_2 equivalents and then multiplies these CO_2 equivalent emission reductions by the social cost of carbon developed by the Interagency Social Cost of Carbon Work Group to generate monetized estimates of the benefits.

The social cost of carbon is an estimate of the net present value of the flow of monetized damages from a 1-metric ton increase in CO_2 emissions in a given year (or from the alternative perspective, the benefit to society of reducing CO_2 emissions by 1 ton). For more information about the social cost of carbon, see the *Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*[47] and RIA for the Light-Duty Vehicle GHG rule.[48] Applying this approach to the methane reductions estimated for the proposed NESHAP and NSPS of the oil and gas rule, the 2015 climate co-benefits vary by discount rate and range from about $370 million to approximately $4.7 billion; the mean social cost of carbon at the 3-percent discount rate results in an estimate of about $1.6 billion in 2015.

The ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. For example, with a 2.5 or 3 percent discount rate, the U.S. benefit is about 7–10 percent of the global benefit, on average, across the scenarios analyzed. Alternatively, if the fraction of GDP lost due to climate change is assumed to be similar across countries, the domestic benefit would be proportional to the U.S. share of global GDP, which is currently about 23 percent. On the basis of this evidence, values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects. It is recognized that these values are approximate, provisional and highly speculative. There is no *a priori* reason why domestic benefits should be a constant fraction of net global damages over time.[49]

These co-benefits equate to a range of approximately $110 to $1,400 per short ton of methane reduced, depending upon the discount rate assumed with a per ton estimate of $480 at the 3-percent discount rate. Methane climate co-benefit estimates for additional regulatory alternatives are included in the RIA for this proposed rule. These social cost of methane benefit estimates are not the same as would be derived from direct computations (using the integrated assessment models employed to develop the Interagency Social Cost of Carbon estimates) for a variety of reasons, including the shorter atmospheric lifetime of methane relative to CO_2 (about 12 years compared to CO_2 whose concentrations in the atmosphere decay on timescales of decades to millennia). The climate impacts also differ between the pollutants for reasons other than the radiative forcing profiles and atmospheric lifetimes of these gases.

Methane is a precursor to ozone and ozone is a short-lived climate forcer that contributes to global warming. The use of the *IPCC Second Assessment Report GWP* to approximate co-benefits may underestimate the direct radiative forcing benefits of reduced ozone levels and does not capture any secondary climate co-benefits involved with ozone-ecosystem interactions. In addition, a recent EPA National Center of Environmental Economics working paper suggests that this quick 'GWP approach' to benefits estimation will likely understate the climate benefits of methane reductions in most cases.[50] This conclusion is reached using the 100-year GWP for methane of 25 as put forth in the *IPCC Fourth Assessment Report (AR 4),* as opposed to the lower

[45] U.S. EPA (2011), *2011 U.S. Greenhouse Gas Inventory Report* Executive Summary available on the internet at *http://www.epa.gov/climateexchange/emissions/downloads11/US-GHG-Inventory-2011-Executive Summary.pdf.*

[46] U.S. EPA. *Greenhouse Gas Equivalency Calculator* available at: *http://www.epa.gov/cleanenergy/energy-resources/calculator.html* accessed 07/19/11.

[47] Interagency Working Group on Social Cost of Carbon (IWGSC). 2010. Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. Docket ID EPA–HQ–OAR–2009–0472–114577. *http://www.epa.gov/otaq/climate/regulations/scc-tsd.pdf;* Accessed March 30, 2011.

[48] U.S. EPA. *Final Rulemaking: Light-Duty Vehicle Greenhouse Gas Emissions Standards and Corporate Average Fuel Economy Standards.* May 2010. Available on the Internet at *http://www.epa.gov/otaq/climate/regulations.htm#finalR.*

[49] Interagency Working Group on Social Cost of Carbon (IWGSC). 2010. *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.*

[50] Marten and Newbold (2011), Estimating the Social Cost of Non-CO_2 *GHG Emissions: Methane and Nitrous Oxide,* NCEE Working Paper Series #11–01. *http://yosemite.epa.gov/EE/epa/eed.nsf/WPNumber/2011-01?OpenDocument.*

value of 21 used in this analysis. Using the higher GWP estimate of 25 would increase these reported methane climate co-benefit estimates by about 19 percent. Although the *IPCC Assessment Report (AR4)* suggested a GWP of 25 for methane, the EPA has used GWP of 21 to estimate the methane climate co-benefits for this oil and gas proposal in order to provide estimates more consistent with global GHG inventories, which currently use GWP from the *IPCC Second Assessment Report.*

Due to the uncertainties involved with the 'GWP approach' estimates presented and methane climate co-benefits estimates available in the literature, the EPA chooses not to compare these co-benefit estimates to the costs of the rule for this proposal. Rather, the EPA presents the 'GWP approach' climate co-benefit estimates as an interim method to produce these estimates until the Interagency Social Cost of Carbon Work Group develops values for non-CO_2 GHG. The EPA requests comments from interested parties and the public about this interim approach specifically and more broadly about appropriate methods to monetize the climate benefits of methane reductions. In particular, the EPA seeks public comments to this proposed rulemaking regarding social cost of methane estimates that may be used to value the co-benefits of methane emission reductions anticipated for the oil and gas industry from this rule. Comments specific to whether GWP is an acceptable method for generating a placeholder value for the social cost of methane until interagency-modeled estimates become available are welcome. Public comments may be provided in the official docket for this proposed rulemaking in accordance with the process outlined earlier in this notice. These comments will be considered in developing the final rule for this rulemaking.

For the proposed NESHAP amendments, a break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health, ecosystem and climate benefits from the reductions in VOC and methane emissions are assumed to be zero. Even though emission reductions of VOC and methane are co-benefits for the proposed NESHAP amendments, they are legitimate components of the total benefit-cost comparison. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the co-benefits to exceed the costs. All estimates are in 2008 dollars. For the proposed NSPS, the revenue from additional product recovery exceeds the costs, which renders a break-even analysis unnecessary when these revenues are included in the analysis. Based on the methodology from Fann, Fulcher, and Hubbell (2009),[51] ranges of benefit-per-ton estimates for emissions of VOC indicate that on average in the United States, VOC emissions are valued from $1,200 to $3,000 per ton as a $PM_{2.5}$ precursor, but emission reductions in specific areas are valued from $280 to $7,000 per ton in 2008 dollars. As a result, even if VOC emissions from oil and natural gas operations result in monetized benefits that are substantially below the national average, there is a reasonable chance that the benefits of the rule would exceed the costs, especially if we were able to monetize all of the additional benefits associated with ozone formation, visibility, HAP and methane.

IX. Request for Comments

We are soliciting comments on all aspects of this proposed action. All comments received during the comment period will be considered. In addition to general comments on the proposed actions, we are also interested in any additional data that may help to reduce the uncertainties inherent in the risk assessments. We are specifically interested in receiving corrections to the datasets used for MACT analyses and risk modeling. Such data should include supporting documentation in sufficient detail to allow characterization of the quality and representativeness of the data or information. Please see the following section for more information on submitting data.

X. Submitting Data Corrections

The facility-specific data used in the source category risk analyses, facility-wide analyses and demographic analyses for each source category subject to this action are available for download on the RTR Web page at *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html.* These data files include detailed information for each HAP emissions release point at each facility included in the source category and all other HAP emissions sources at these facilities (facility-wide emissions sources). However, it is important to note that the source category risk analysis included only those emissions tagged with the MACT code associated with the source category subject to the risk analysis.

If you believe the data are not representative or are inaccurate, please identify the data in question, provide your reason for concern and provide any "improved" data that you have, if available. When you submit data, we request that you provide documentation of the basis for the revised values to support your suggested changes. To submit comments on the data downloaded from the RTR Web page, complete the following steps:

1. Within this downloaded file, enter suggested revisions to the data fields appropriate for that information. The data fields that may be revised include the following:

Data element	Definition
Control Measure	Are control measures in place? (yes or no).
Control Measure Comment	Select control measure from list provided and briefly describe the control measure.
Delete	Indicate here if the facility or record should be deleted.
Delete Comment	Describes the reason for deletion.
Emission Calculation Method Code for Revised Emissions.	Code description of the method used to derive emissions. For example, CEM, material balance, stack test, etc.
Emission Process Group	Enter the general type of emission process associated with the specified emission point.
Fugitive Angle	Enter release angle (clockwise from true North); orientation of the y-dimension relative to true North, measured positive for clockwise starting at 0 degrees (maximum 89 degrees).
Fugitive Length	Enter dimension of the source in the east-west (x-) direction, commonly referred to as length (ft).

[51] Fann, N., C.M. Fulcher, B.J. Hubbell. *The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution.* Air Qual Atmos Health (2009) 2:169–176.

Data element	Definition
Fugitive Width	Enter dimension of the source in the north-south (y-) direction, commonly referred to as width (ft).
Malfunction Emissions	Enter total annual emissions due to malfunctions (TPY).
Malfunction Emissions Max Hourly	Enter maximum hourly malfunction emissions here (lb/hr).
North American Datum	Enter datum for latitude/longitude coordinates (NAD27 or NAD83); if left blank, NAD83 is assumed.
Process Comment	Enter general comments about process sources of emissions.
REVISED Address	Enter revised physical street address for MACT facility here.
REVISED City	Enter revised city name here.
REVISED County Name	Enter revised county name here.
REVISED Emission Release Point Type	Enter revised Emission Release Point Type here.
REVISED End Date	Enter revised End Date here.
REVISED Exit Gas Flow Rate	Enter revised Exit Gas Flowrate here (ft^3/sec).
REVISED Exit Gas Temperature	Enter revised Exit Gas Temperature here (OF).
REVISED Exit Gas Velocity	Enter revised Exit Gas Velocity here (ft/sec).
REVISED Facility Category Code	Enter revised Facility Category Code here, which indicates whether facility is a major or area source.
REVISED Facility Name	Enter revised Facility Name here.
REVISED Facility Registry Identifier	Enter revised Facility Registry Identifier here, which is an ID assigned by the EPA Facility Registry System.
REVISED HAP Emissions Performance Level Code	Enter revised HAP Emissions Performance Level here.
REVISED Latitude	Enter revised Latitude here (decimal degrees).
REVISED Longitude	Enter revised Longitude here (decimal degrees).
REVISED MACT Code	Enter revised MACT Code here.
REVISED Pollutant Code	Enter revised Pollutant Code here.
REVISED Routine Emissions	Enter revised routine emissions value here (TPY).
REVISED SCC Code	Enter revised SCC Code here.
REVISED Stack Diameter	Enter revised Stack Diameter here (ft).
REVISED Stack Height	Enter revised Stack Height here (Ft).
REVISED Start Date	Enter revised Start Date here.
REVISED State	Enter revised state here.
REVISED Tribal Code	Enter revised Tribal Code here.
REVISED Zip Code	Enter revised Zip Code here.
Shutdown Emissions	Enter total annual emissions due to shutdown events (TPY).
Shutdown Emissions Max Hourly	Enter maximum hourly shutdown emissions here (lb/hr).
Stack Comment	Enter general comments about emission release points.
Startup Emissions	Enter total annual emissions due to startup events (TPY).
Startup Emissions Max Hourly	Enter maximum hourly startup emissions here (lb/hr).
Year Closed	Enter date facility stopped operations.

2. Fill in the commenter information fields for each suggested revision (*i.e.,* commenter name, commenter organization, commenter e-mail address, commenter phone number and revision comments).

3. Gather documentation for any suggested emissions revisions (*e.g.,* performance test reports, material balance calculations, etc.).

4. Send the entire downloaded file with suggested revisions in Microsoft® Access format and all accompanying documentation to Docket ID Number EPA–HQ–OAR–2010–0505 (through one of the methods described in the **ADDRESSES** section of this preamble). To expedite review of the revisions, it would also be helpful if you submitted a copy of your revisions to the EPA directly at *RTR@epa.gov* in addition to submitting them to the docket.

5. If you are providing comments on a facility with multiple source categories, you need only submit one file for that facility, which should contain all suggested changes for all source categories at that facility. We request that all data revision comments be submitted in the form of updated Microsoft® Access files, which are provided on the *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html* Web page.

XI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to OMB for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 8 shows the results of the cost and benefits analysis for these proposed rules. For more information on the benefit and cost analysis, as well as details on the regulatory options considered, please refer to the RIA for this rulemaking, which is available in the docket.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, COSTS AND NET BENEFITS FOR THE PROPOSED OIL AND NATURAL GAS NSPS AND NEHSAP AMENDMENTS IN 2015

[Millions of 2008$] [1]

	Proposed NSPS	Proposed NESHAP amendments	Proposed NSPS and NESHAP amendments combined
Total Monetized Benefits [2]	N/A	N/A	N/A.
Total Costs [3]	−$45 million	$16 million	−$29 million.
Net Benefits	N/A	N/A	N/A.
Non-monetized Benefits [4 5]	37,000 tons of HAP 540,000 tons of VOC 3.4 million tons of methane	1,400 tons of HAP 9,200 tons of VOC 4,900 tons of methane	38,000 tons of HAP. 540,000 tons of VOC. 3.4 million tons of methane.
	Health effects of HAP exposure. Health effects of $PM_{2.5}$ and ozone exposure. Visibility impairment. Vegetation effects. Climate effects.		

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAP, ozone and PM, as well as climate effects associated with methane, we have determined that quantification of those benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available.

[3] The engineering compliance costs are annualized using a 7-percent discount rate. The negative cost for the proposed NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS.

[4] For the NSPS, reduced exposure to HAP and climate effects are co-benefits. For the NESHAP, reduced VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects and climate effects are co-benefits.

[5] The specific control technologies for these proposed rules are anticipated to have minor secondary disbenefits. The net CO_2-equivalent emission reductions are 93,000 metric tons for the NESHAP and 62 million metric tons for the NSPS.

B. Paperwork Reduction Act

The information collection requirements in this proposed action have been submitted for approval to OMB under the *Paperwork Reduction Act,* 44 U.S.C. 3501, *et seq.* The ICR document prepared by the EPA has been assigned EPA ICR Numbers 1716.07 (40 CFR part 60, subpart OOOO), 1788.10 (40 CFR part 63, subpart HH), 1789.07 (40 CFR part 63, subpart HHH) and 1086.10 (40 CFR part 60, subparts KKK and subpart LLL).

The information to be collected for the proposed NSPS and the proposed NESHAP amendments are based on notification, recordkeeping and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

These proposed rules would require maintenance inspections of the control devices, but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

For sources subject to the proposed NSPS, burden changes associated with these amendments result from the respondents' annual reporting and recordkeeping burden associated with this proposed rule for this collection (averaged over the first 3 years after the effective date of the standards). The burden is estimated to be 560,000 labor hours at a cost of $18 million per year. This includes the burden previously estimated for sources subject to 40 CFR part 60, subpart KKK (which is being incorporated into 40 CFR part 60, subpart OOOO). The average hours and cost per regulated entity subject to the NSPS for oil and natural gas production and natural gas transmissions and distribution facilities would be 110 hours per response and $3,693 per response, based on an average of 1,459 operators responding per year and 16 responses per year.

The estimated recordkeeping and reporting burden after the effective date of the proposed amendments is estimated for all affected major and area sources subject to the Oil and Natural Gas Production NESHAP to be approximately 63,000 labor hours per year at a cost of $2.1 million per year. For the Natural Gas Transmission and Storage NESHAP, the recordkeeping and reporting burden is estimated to be 2,500 labor hours per year at a cost of $86,800 per year. This estimate includes the cost of reporting, including reading instructions and information gathering. Recordkeeping cost estimates include reading instructions, planning activities and conducting compliance monitoring. The average hours and cost per regulated entity subject to the Oil and Natural Gas Production NESHAP would be 72 hours per year and $2,500 per year, based on an average of 846 facilities per year and three responses per facility. For the Natural Gas Transmission and Storage NESHAP, the average hours and cost per regulated entity would be 50 hours per year and $1,600 per year, based on an average of 53 facilities per year and three responses per facility. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden, the EPA has established a public docket for this rule, which includes this ICR, under Docket ID Number EPA–HQ–OAR–2010–0505. Submit any comments related to the ICR to the EPA and OMB. See the **ADDRESSES** section at the beginning of this notice for where to submit comments to the

EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after August 23, 2011, a comment to OMB is best assured of having its full effect if OMB receives it by September 22, 2011. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities (SISNOSE). Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) A small business whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Proposed NSPS

After considering the economic impact of the proposed NSPS on small entities, I certify that this action will not have a SISNOSE. The EPA performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. Based upon the analysis in the RIA, which is in the Docket, EPA concludes the number of impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to REC activities occur without a significant time lag between implementing the control and obtaining the recovered product, unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions and recompletions occur over a short span of time, during which the additional product recovery is also accomplished.

Proposed NESHAP Amendments

After considering the economic impact of the proposed NESHAP amendments on small entities, I certify that this action will not have a SISNOSE. Based upon the analysis in the RIA, which is in the Docket, we estimate that 62 of the 118 firms (53 percent) that own potentially affected facilities are small entities. The EPA performed a screening analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, *10 firms (16 percent)* are likely to have impacts greater than 1 percent. Four of these *10* firms are likely to have impacts greater than 3 percent. While these *10* firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211. Although this final rule will not impact a substantial number of small entities, the EPA, nonetheless, has tried to reduce the impact of this rule on small entities by setting the final emissions limits at the MACT floor, the least stringent level allowed by law.

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

This action contains no Federal mandates under the provisions of title II of the *Unfunded Mandates Reform Act of 1995* (UMRA), 2 U.S.C. 1531–1538 for state, local or tribal governments or the private sector. This proposed rule does not contain a Federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or to the private sector in any one year. Thus, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA. This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This action contains no requirements that apply to such governments nor does it impose obligations upon them.

E. Executive Order 13132: Federalism

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this proposed rule. In the spirit of Executive Order 13132 and consistent with the EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed rule from state and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effect on tribal governments, on the relationship between the Federal government and Indian tribes or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

The EPA specifically solicits additional comment on this proposed action from tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This proposed rule is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This actions' health and risk assessments are contained in section VII.C of this preamble.

The public is invited to submit comments or identify peer-reviewed studies and data that assess effects of early life exposure to HAP from oil and natural gas sector activities.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

Executive Order 13211, (66 FR 28,355, May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.''

The proposed rules will result in the addition of control equipment and monitoring systems for existing and new sources within the oil and natural gas industry. The proposed NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution or use of energy. As such, the proposed NESHAP amendments are not ''significant energy actions'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001).

The proposed NSPS is also unlikely to have a significant effect on the supply, distribution or use of energy. As such, the proposed NSPS is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001). The basis for the determination is as follows.

As discussed in the impacts section of the Preamble, we use the NEMS to estimate the impacts of the proposed NSPS on the United States energy system. The NEMS is a publically available model of the United States energy economy developed and maintained by the Energy Information Administration of the United States DOE and is used to produce the *Annual Energy Outlook,* a reference publication that provides detailed forecasts of the United States energy economy.

Proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One pollution control requirement of the proposed NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the proposed NSPS.

The analysis of energy impacts for the proposed NSPS that includes the additional product recovery shows that domestic natural gas production is estimated to increase (20 billion cubic feet or 0.1 percent) and natural gas prices to decrease ($0.04/Mcf or 0.9 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. Domestic crude oil production is not estimated to change, while crude oil prices are estimated to decrease slightly ($0.02/barrel or less than 0.1 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. All prices are in 2008 dollars.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden.

For more information on the estimated energy effects, please refer to the economic impact analysis for this proposed rule. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104–113 (15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the requirements of the NTTAA apply to this action. We are proposing to revise 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH to allow ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses (Part 10, Instruments and Apparatus) to be used in lieu of EPA Methods 3B, 6 and 16A. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990. Also, we are proposing to revise subpart HHH to allow ASTM D6420–99 (2004), *Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry,* to be used in lieu of EPA Method 18. For a detailed discussion of this VCS, and its appropriateness as a substitute for Method 18, see the final Oil and Natural Gas Production NESHAP (Area Sources) (72 FR 36, January 3, 2007).

As a result, the EPA is proposing ASTM D6420–99 (2004) for use in 40 CFR part 63, subpart HHH. The EPA also proposes to allow Method 18 as an option in addition to ASTM D6420–99 (2004). This would allow the continued use of gas chromatography configurations other than gas chromatography/mass spectrometry.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on EJ. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations in the United States.

The EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

To examine the potential for any EJ issues that might be associated with each source category, we evaluated the distributions of HAP-related cancer and noncancer risks across different social, demographic and economic groups within the populations living near the facilities where these source categories are located. The methods used to conduct demographic analyses for this rule are described in section VII.C of the preamble for this rule. The development of demographic analyses to inform the consideration of EJ issues in EPA rulemakings is an evolving science. The EPA offers the demographic analyses in this proposed rulemaking as examples of how such analyses might be developed to inform such consideration, and invites public comment on the approaches used and the interpretations made from the results, with the hope that this will support the refinement and improve utility of such analyses for future rulemakings.

For the demographic analyses, we focused on the populations within 50 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater, or noncancer HI of 1 or greater (based on the emissions of the source category or the facility, respectively). We examined the distributions of those risks across various demographic groups, comparing the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. The results, including other risk metrics, such as average risks for the exposed populations, are documented in source category-specific technical reports in the docket for both source categories covered in this proposal.

As described in the preamble, our risk assessments demonstrate that the regulations for the oil and natural gas production and natural gas transmission and storage source categories, are associated with an acceptable level of risk and that the proposed additional requirements will provide an ample margin of safety to protect public health. Our analyses also show that, for these source categories, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic noncancer health impacts are unlikely. The EPA has determined that, although there may be an existing disparity in HAP risks from these sources between some demographic groups, no demographic group is exposed to an unacceptable level of risk.

List of Subjects

40 CFR Part 60

Environmental protection, Air pollution control, Reporting and recordkeeping requirements, Volatile organic compounds.

40 CFR Part 63

Environmental protection, Air pollution control, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: July 28, 2011.

Lisa P. Jackson,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is proposed to be amended as follows:

PART 60—[AMENDED]

1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

2. Section 60.17 is amended by:

a. Revising paragraph (a)(7); and

b. Revising paragraphs (a)(91) and (a)(92) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(7) ASTM D86–78, 82, 90, 93, 95, 96, Distillation of Petroleum Products, IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), 60.633(h) and 60.5401(h).

* * * * *

(91) ASTM E169–63, 77, 93, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), 60.632(f) and 60.5400(f).

(92) ASTM E260–73, 91, 96, General Gas Chromatography Procedures, IBR approved for §§ 60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), 60.632(f), 60.5400(f) and 60.5406(b).

* * * * *

Subpart KKK—Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011

3. The heading for Subpart KKK is revised to read as set out above.

4. Section 60.630 is amended by revising paragraph (b) to read as follows:

§ 60.630 Applicability and designation of affected facility.

* * * * *

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 20, 1984, and on or before August 23, 2011, is subject to the requirements of this subpart.

* * * * *

Subpart LLL—Standards of Performance for SO_2 Emissions From Onshore Natural Gas Processing for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011

5. The heading for Subpart LLL is revised to read as set out above.

6. Section 60.640 is amended by revising paragraph (d) to read as follows:

§ 60.640 Applicability and designation of affected facilities.

* * * * *

(d) The provisions of this subpart apply to each affected facility identified in paragraph (a) of this section which commences construction or modification after January 20, 1984, and on or before August 23, 2011.

* * * * *

7. Add subpart OOOO to part 60 to read as follows:

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution

Sec.

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution

§ 60.5360 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities that commenced construction, modification or reconstruction after August 23, 2011.

§ 60.5365 Am I subject to this subpart?

If you are the owner or operator of one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.

(a) A gas wellhead affected facility, is a single natural gas well.

(b) A centrifugal compressor affected facility, which is defined as a single centrifugal compressor located between the wellhead and the city gate (as defined in § 60.5430), except that a centrifugal compressor located at a well site (as defined in § 60.5430) is not an affected facility under this subpart. For the purposes of this subpart, your centrifugal compressor is considered to have commenced construction on the date the compressor is installed at the facility.

(c) A reciprocating compressor affected facility, which is defined as a single reciprocating compressor located between the wellhead and the city gate (as defined in § 60.5430), except that a reciprocating compressor located at a well site (as defined in § 60.5430) is not an affected facility under this subpart. For the purposes of this subpart, your reciprocating compressor is considered to have commenced construction on the date the compressor is installed at the facility.

(d) A pneumatic controller affected facility, which is defined as a single pneumatic controller.

(e) A storage vessel affected facility, which is defined as a single storage vessel.

(f) Compressors and equipment (as defined in § 60.5430) located at onshore natural gas processing plants.

(1) Each compressor in VOC service or in wet gas service is an affected facility.

(2) The group of all equipment, except compressors, within a process unit is an affected facility.

(3) Addition or replacement of equipment, as defined in § 60.5430, for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(4) Equipment (as defined in § 60.5430) associated with a compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit is covered by §§ 60.5400, 60.5401, 60.5402, 60.5421 and 60.5422 of this subpart if it is located at an onshore natural gas processing plant. Equipment (as defined in § 60.5430) not located at the onshore natural gas processing plant site is exempt from the provisions of §§ 60.5400, 60.5401, 60.5402, 60.5421 and 60.5422 of this subpart.

(5) Affected facilities located at onshore natural gas processing plants and described in paragraphs (f)(1) and (f)(2) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

(g) Sweetening units located onshore that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423(c) but are not required to comply with §§ 60.5405 through 60.5407 and paragraphs 60.5410(g) and 60.5415(g) of this subpart.

(4) Sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405 through 60.5407, and §§ 60.5410(g), 60.5415(g), and § 60.5423 of this subpart.

§ 60.5370 When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than the date of publication of the final rule in the **Federal Register** or upon startup, whichever is later.

(b) The provisions for exemption from compliance during periods of startup, shutdown, and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 60.5375 What standards apply to gas wellhead affected facilities?

If you are the owner or operator of a gas wellhead affected facility, you must comply with paragraphs (a) through (g) of this section.

(a) Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing, as defined in § 60.5430, you must control emissions by the operational procedures found in paragraphs (a)(1) through (a)(3) of this section.

(1) You must minimize the emissions associated with venting of hydrocarbon fluids and gas over the duration of flowback by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system.

(2) You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations to safely maximize resource recovery and minimize releases to the environment. All salable quality gas must be routed to the gas gathering line as soon as practicable.

(3) You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.

(b) You must maintain a log for each well completion operation at each gas wellhead affected facility. The log must be completed on a daily basis and must contain the records specified in § 60.5420(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to gas wellhead affected facilities as required by § 60.5410.

(d) You must demonstrate continuous compliance with the standards that apply to gas wellhead affected facilities as required by § 60.5415.

(e) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

(f) For wells meeting the criteria for wildcat or delineation wells, each well completion operation with hydraulic fracturing at a gas wellhead affected facility must reduce emissions by using a completion combustion device meeting the requirements of paragraph (a)(3) of this section. You must also maintain records specified in § 60.5420(c)(1)(iii) for wildcat or delineation wells.

§ 60.5380 What standards apply to centrifugal compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section, as applicable for each centrifugal compressor affected facility.

(a) You must equip each rotating compressor shaft with a dry seal system upon initial startup.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410.

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5385 What standards apply to reciprocating compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) You must replace the reciprocating compressor rod packing before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or the date of publication of the final rule in the **Federal Register**, or the date of the previous reciprocating compressor rod packing replacement, whichever is later.

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410.

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5390 What standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, in either paragraph (b) or (c) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) are exempt from this requirement.

(a) The requirements of paragraph (b) or (c) of this section are not required if you demonstrate, to the Administrator's satisfaction, that the use of a high bleed device is predicated. The demonstration may include, but is not limited to, response time, safety and actuation.

(b) Each pneumatic controller affected facility located at a natural gas processing plant (as defined in § 60.5430) must have zero emissions of natural gas.

(c) Each pneumatic controller affected facility not located at a natural gas processing plant (as defined in § 60.5430) must have natural gas emissions no greater than 6 standard cubic feet per hour.

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5410.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5415.

(f) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420, except that you are not required to submit the notifications specified in § 60.5420(a).

§ 60.5395 What standards apply to storage vessel affected facilities?

You must comply with the standards in paragraphs (a) through (e) of this section for each storage vessel affected facility.

(a) You must comply with the standards for storage vessels specified in § 63.766(b) and (c) of this chapter, except as specified in paragraph (b) of this section. Storage vessels that meet either one or both of the throughput conditions specified in paragraphs (a)(1) or (a)(2) of this section are not subject to the standards of this section.

(1) The annual average condensate throughput is less than 1 barrel per day per storage vessel.

(2) The annual average crude oil throughput is less than 20 barrels per day per storage vessel.

(b) This standard does not apply to storage vessels already subject to and controlled in accordance with the requirements for storage vessels in § 63.766(b)(1) or (2) of this chapter.

(c) You must demonstrate initial compliance with standards that apply to storage vessel affected facilities as required by § 60.5410.

(d) You must demonstrate continuous compliance with standards that apply to storage vessel affected facilities as required by § 60.5415.

(e) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5400 What VOC standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to each compressor in VOC service or in wet gas service and the group of all equipment (as defined in § 60.5430), except compressors, within a process unit.

(a) You must comply with the requirements of § 60.482–1a(a), (b), and (d), § 60.482–2a, and § 60.482–4a through 60.482–11a, except as provided in § 60.5401.

(b) You may elect to comply with the requirements of §§ 60.483–1a and 60.483–2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5402 of this subpart.

(d) You must comply with the provisions of § 60.485a of this part except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§ 60.486a and 60.487a of this part except as provided in §§ 60.5401, 60.5421, and 60.5422 of this part.

(f) You must use the following provision instead of § 60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169–63, 77, or 93, E168–67, 77, or 92, or E260–73, 91, or 96 (incorporated by reference as specified in § 60.17) must be used.

§ 60.5401 What are the exceptions to the VOC standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of subpart VVa of this part.

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in § 60.485a(b) except as provided in § 60.5400(c) and in paragraph (b)(4) of this section, and § 60.482–4a(a) through (c) of subpart VVa.

(2) If an instrument reading of 5000 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in § 60.482–9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482–4a(b)(1) of subpart VVa.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of § 60.482–5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant with a design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1) and 60.482–7a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), and paragraph (b)(1) of this section.

(f) Flares used to comply with this subpart must comply with the requirements of § 60.18.

(g) An owner or operator may use the following provisions instead of § 60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86–78, 82, 90, 95, or 96 (incorporated by reference as specified in § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86–78, 82, 90, 95, or 96 (incorporated by reference as specified in § 60.17).

§ 60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

§ 60.5405 What standards apply to sweetening units at onshore natural gas processing plants?

(a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in § 60.8, you must use the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in paragraph § 60.8(b).

(b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in § 60.5405(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$X - KQ_a\gamma$

Where:

X = average sulfur feed rate, Mg/D (LT/D).
Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).
Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.
K = (32 kg S/kg-mole) / ((24.04 dscm/kg-mole) (1000 kg S/Mg))
= 1.331×10^{-3} Mg/dscm, for metric units
= (32 lb S/lb-mole) / ((385.36 dscf/lb-mole) (2240 lb S/long ton))
= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in § 60.5408 or a chromatographic procedure following ASTM E–260 (incorporated by reference—see § 60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (b)(3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in § 60.5405(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100S)\frac{\square}{S+E}$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage tanks. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = \frac{C_e Q_{sd}}{K_1}$$

Where:

E = emission rate of sulfur per run, kg/hr.
C_e = concentration of sulfur equivalent (SO_2 + reduced sulfur), g/dscm (lb/dscf).
Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).
K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of Appendix A to part 60 of this chapter to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m² (54 ft²) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m² or more, and the centroid is more than 1 m (39 in.) from the wall.

(i) You must use Method 6 of Appendix A to part 60 of this chapter to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent.

(ii) You must use Method 15 of appendix A to part 60 of this chapter to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft³/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A or Method 15 of appendix A to part 60 of this chapter to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A to part 60 of this chapter to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

§ 60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of § 60.5405(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) *The accumulation of sulfur product over each 24-hour period.* The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage tanks with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ± 2 percent of the 24-hour sulfur accumulation.

(2) *The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period.* At least one sample per 24-hour period must be collected and analyzed using the equation specified in § 60.5406(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is

within ± 20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ± 20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) *The average acid gas flow rate from the sweetening unit.* You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) *The sulfur feed rate (X).* For each 24-hour period, you must compute X using the equation specified in § 60.5406(b)(3).

(5) *The required sulfur dioxide emission reduction efficiency for the 24-hour period.* You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) *A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere.* The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ± 1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock internal. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B to part 60 of this chapter must apply, and Method 6 must be used for systems required by paragraph (b) of this section.

§ 60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure? [1]

(a) When an instantaneous sample is desired and H_2S concentration is ten grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than ten grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top which connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml = 0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure.* Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine thru (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

Grains H_2S per 100 cubic foot of gas = $100\ (D - C)$

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

BILLING CODE 6560–50–P

[1] Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A–80–20–A, Entry II–I–67).

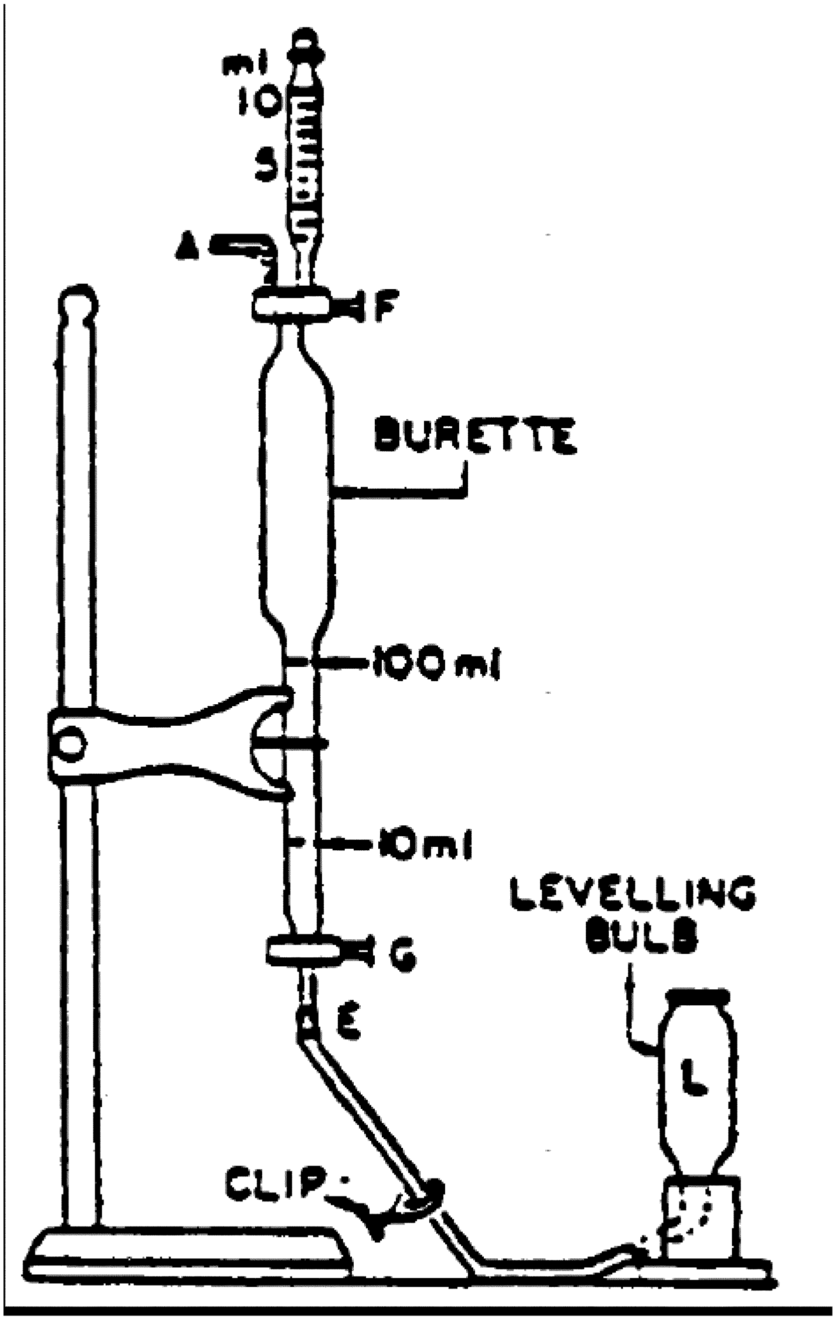

Figure 1. Tutwiler burette (lettered items mentioned in text).

BILLING CODE 6560–50–C

§ 60.5410 How do I demonstrate initial compliance with the standards for my gas wellhead affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (g) of this section. The initial compliance period begins on the date of publication of the final rule in the **Federal Register** or upon initial startup, whichever is later, and ends on the date the first annual report is due as specified in § 60.5420(b).

(a) You have achieved initial compliance with standards for each well completion operation conducted at your gas wellhead affected facility if you have complied with paragraphs (a)(1) and (a)(2) of this section.

(1) You have notified the Administrator within 30 days of the commencement of the well completion operation, the date of the commencement of the well completion operation, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum (NAD) of 1983.

(2) You have maintained a log of records as specified in § 60.5375(b) or (f) for each well completion operation conducted during the initial compliance period.

(3) You have submitted the initial annual report for your wellhead affected facility as required in § 60.5420(b).

(b) You have achieved initial compliance with standards for your centrifugal compressor affected facility if the centrifugal compressor is fitted with a dry seal system upon initial startup as required by § 60.5380.

(c) You have achieved initial compliance with standards for each reciprocating compressor affected facility if you have complied with paragraphs (c)(1) and (c)(2) of this section.

(1) During the initial compliance period, you have continuously monitored the number of hours of operation.

(2) You have included the cumulative number of hours of operation for your reciprocating compressor affected facility during the initial compliance period in your initial annual report required in § 60.5420(b).

(d) You have achieved initial compliance with emission standards for your pneumatic controller affected facility if you comply with the requirements specified in paragraphs (d)(1) through (d)(4) of this section.

(1) You have demonstrated, to the Administrator's satisfaction, the use of a high bleed device is predicated as specified in § 60.5490(a).

(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven other than by use of natural gas and therefore emits zero natural gas.

(3) You own or operate a pneumatic controller affected facility not located at a natural gas processing plant and the manufacturer's design specifications guarantee the controller emits less than or equal to 6.0 standard cubic feet of gas per hour.

(4) You have included the information in paragraphs (d)(1) through (d)(3) of this section in the initial annual report submitted for your pneumatic controller affected facilities according to the requirements of § 60.5420(b).

(e) You have demonstrated initial compliance with emission standards for your storage vessel affected facility if you are complying with paragraphs (e)(1) through (e)(7) of this section.

(1) You have equipped the storage vessel with a closed vent system that meets the requirements of § 63.771(c) of this chapter connected to a control device that meets the conditions specified in § 63.771(d).

(2) You have conducted an initial performance test as required in § 63.772(e) of this chapter within 180 days after initial startup or the date of publication of the final rule in the **Federal Register** and have conducted the compliance demonstration in § 63.772(f).

(3) You have conducted the initial inspections required in § 63.773(c) of this chapter.

(4) You have installed and operated continuous parameter monitoring systems in accordance with § 63.773(d) of this chapter.

(5) If you are exempt from the standards of § 60.5395 according to § 60.5395(a)(1) or (a)(2), you have determined the condensate or crude oil throughput, as applicable, according to paragraphs (e)(5)(i) or (e)(5)(ii) of this section and demonstrated to the Administrator's satisfaction that your annual average condensate throughput is less than 1 barrel per day per tank and your annual average crude oil throughput is less than 20 barrels per day per tank.

(i) You have installed and operated a flow meter to measure condensate or crude oil throughput in accordance with the manufacturer's procedures or specifications.

(ii) You have used any other method approved by the Administrator to determine annual average condensate or crude oil throughput.

(6) You have submitted the information in paragraphs (e)(1) through (e)(5) of this section in the initial annual report for your storage vessel affected facility as required in § 60.5420(b).

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (g)(3) of this section.

(1) To determine compliance with the standards for SO_2 specified in § 60.5405(a), during the initial performance test as required by § 60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (g)(1)(ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).

(3) You have submitted the results of paragraphs (g)(1) and (g)(2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

§ 60.5415 How do I demonstrate continuous compliance with the standards for my gas wellhead affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

(a) For each gas wellhead affected facility, you must demonstrate continuous compliance by maintaining the records for each completion operation (as defined in § 60.5430) specified in § 60.5420.

(b) For each centrifugal compressor affected facility, continuous compliance is demonstrated if the rotating compressor shaft is equipped with a dry seal.

(c) For each reciprocating compressor affected facility, you have demonstrated continuous compliance according to paragraphs (c)(1) and (2) of this section

(1) You have continuously monitored the number of hours of operation for each reciprocating compressor affected facility since initial startup, or the date of publication of the final rule in the **Federal Register**, or the date of the previous reciprocating compressor rod packing replacement, whichever is later. The cumulative number of hours of operation must be included in the annual report as required in § 60.5420(b)(4).

(2) You have replaced the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours.

(d) For each pneumatic controller affected facility, continuous compliance is demonstrated by maintaining the records demonstrating that you have installed and operated the pneumatic controllers as required in § 60.5390(a), (b) or (c).

(e) For each storage vessel affected facility, continuous compliance is demonstrated according to § 63.772(f) of this chapter.

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO_2 specified in

§ 60.5405(b) according to paragraphs (g)(1) and (g)(2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).

(h) *Affirmative defense for exceedance of emission limit during malfunction.* In response to an action to enforce the standards set forth in §§ 60.5375, 60.5380, 60.5385, 60.5390, 60.5395, 60.5400, and 60.5405, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at § 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in § 60.5420(a), and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) The owner or operator of the facility experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standards in §§ 60.5375, 60.5380, 60.5385, 60.5390, 60.5395, and 60.5400 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45-day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

§ 60.5420 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications required in § 60.7(a)(1), (a)(3) and (a)(4), and according to paragraphs (a)(1) and (a)(2) of this section, if you own or operate one or more of the affected facilities specified in § 60.5365. For the purposes of this subpart, a workover that occurs after August 23, 2011 at each affected facility for which construction, reconstruction, or modification commenced on or before August 23, 2011 is considered a modification for which a notification must be submitted under § 60.7(a)(4).

(1) If you own or operate a pneumatic controller affected facility you are not required to submit the notifications required in § 60.7(a)(1), (a)(3) and (a)(4).

(2) If you own or operate a gas wellhead affected facility, you must submit a notification to the Administrator within 30 days of the commencement of the well completion operation. The notification must include the date of commencement of the well completion operation, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (b)(6) of this section to the Administrator. The initial annual report is due 1 year after the initial startup date for your affected facility or 1 year after the date of publication of the final rule in the **Federal Register,** whichever is later. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (b)(6) of this section.

(1) The general information specified in paragraphs (b)(1)(i) through (b)(1)(iii) of this section.

(i) The company name and address of the affected facility.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(2) For each gas wellhead affected facility, the information in paragraphs (b)(2)(i) through (b)(2)(iii) of this section.

(i) An identification of each well completion operation, as defined in § 60.5430, for each gas wellhead affected facility conducted during the reporting period;

(ii) A record of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375 for each gas well affected facility.

(iii) Records specified in § 60.5375(b) for each well completion operation that occurred during the reporting period.

(3) For each centrifugal compressor affected facility installed during the reporting period, documentation that the centrifugal compressor is equipped with dry seals.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) and (b)(4)(ii) of this section.

(i) The cumulative number of hours or operation since initial startup, the date of publication of the final rule in the **Federal Register**, or since the previous reciprocating compressor rod packing replacement, whichever is later.

(ii) Documentation that the reciprocating compressor rod packing was replaced before the cumulative number of hours of operation reached 24,000 hours.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (b)(5)(iv) of this section.

(i) The date, location and manufacturer specifications for each pneumatic controller installed.

(ii) If applicable, documentation that the use of high bleed pneumatic devices is predicated and the reasons why.

(iii) For pneumatic controllers not installed at a natural gas processing plant, the manufacturer's guarantee that the device is designed such that natural gas emissions are less than 6 standard cubic feet per hour.

(iv) For pneumatic controllers installed at a natural gas processing plant, documentation that each controllers has zero natural gas emissions.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) and (b)(6)(ii) of this section.

(i) If required to reduce emissions by complying with § 60.5395(a)(1), the records specified in § 63.774(b)(2) through (b)(8) of this chapter.

(ii) Documentation that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage for meeting the requirements in § 60.5395(a)(1) or (a)(2).

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (c)(5) of this section

(1) The records for each gas wellhead affected facility as specified in paragraphs (c)(1)(i) through (c)(1)(iii).

(i) Records identifying each well completion operation for each gas wellhead affected facility conducted during the reporting period;

(ii) Record of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375.

(iii) Records required in § 60.5375(b) or (f) for each well completion operation conducted for each gas wellhead affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (c)(1)(iii)(B) of this section.

(A) For each gas wellheads affected facility required to comply with the requirements of § 60.5375(a), you must record: The location of the well; the duration of flowback; duration of recovery to the sales line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.

(B) For each gas wellhead affected facility required to comply with the requirements of § 60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the sales line. In addition, you must record the distance, in miles, of the nearest gathering line.

(2) For each centrifugal compressor affected facility, you must maintain records on the type of seal system installed.

(3) For each reciprocating compressors affected facility, you must maintain the records in paragraphs (c)(3)(i) and (c)(3)(ii) of this section.

(i) Records of the cumulative number of hours of operation since initial startup or the date of publication of the final rule in the **Federal Register**, or the previous replacement of the reciprocating compressor rod packing, whichever is later.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (c)(4)(iv) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller installed.

(ii) Records of the determination that the use of high bleed pneumatic devices is predicated and the reasons why.

(iii) If the pneumatic controller affected facility is not located at a natural gas processing plant, records of the manufacturer's guarantee that the device is designed such that natural gas emissions are less than 6 standard cubic feet per hour.

(iv) If the pneumatic controller affected facility is located at a natural gas processing plant, records of the documentation that only instrument air controllers are used.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.

(i) If required to reduce emissions by complying with § 63.766, the records specified in § 63.774(b)(2) through (8) of this chapter.

(ii) Records of the determination that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage vessel for the exemption under § 60.5395(a)(1) and (a)(2).

§ 60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of § 60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of § 60.5401(b)(1) of this subpart.

(1) When each leak is detected as specified in § 60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in § 60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) "Above 500 ppm" if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(v) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482–4a(a). The designation of equipment subject to the provisions of § 60.482–4a(a) must be signed by the owner or operator.

§ 60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii).

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of § 60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482–4a(a) and those pressure relief devices complying with § 60.482–4a(c).

(c) An owner or operator must include the following information in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in § 60.5401(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in § 60.5401(b)(3).

§ 60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in § 60.5405(a) and (b) and § 60.5407(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(d) of the General Provisions.

(b) You must submit a written report of excess emissions to the Administrator semiannually. For the purpose of these reports, excess emissions are defined as:

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of § 60.5407(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407(b)(2). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less that 2 LT/D of H_2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with § 60.5407(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H_2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state.

§ 60.5425 What part of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5430 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Centrifugal compressor means a piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers.

City gate means the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions or workovers.

Compressor means a piece of equipment that compresses process gas and is usually a centrifugal compressor or a reciprocating compressor.

Compressor station means any permanent combination of compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

Condensate means a hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions, as specified in § 60.2. For the purposes of this subpart, a hydrocarbon liquid with an API gravity equal to or greater than 40 degrees is considered condensate.

Crude oil means crude petroleum oil or any other hydrocarbon liquid, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir. For the purposes of this subpart, a hydrocarbon liquid with an API gravity less than 40 degrees is considered crude oil.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Equipment means each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used to transport field gas from a field to the main pipeline in the area.

Flare means a thermal oxidation system using an open (without enclosure) flame.

Flowback means the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production.

Flow line means surface pipe through which oil and/or natural gas travels from the well.

Gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Gas well means a well, the principal production of which at the mouth of the well is gas.

High-bleed pneumatic devices means automated, continuous bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

Hydraulic fracturing means the process of directing pressurized liquids, containing water, proppant, and any added chemicals, to penetrate tight sand, shale, or coal formations that involve high rate, extended back flow to expel fracture fluids and sand during completions and well workovers.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e) or § 60.5401(h)(2) of this part.

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Low-bleed pneumatic controller means automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non gas-driven pneumatic device means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Plunger lift system means an intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger, and the column of fluid ahead of it, up the well tubing to the surface.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Reduced emissions completion means a well completion where gas flowback that is otherwise vented is captured, cleaned, and routed to the sales line.

Reduced emissions recompletion means a well completion following refracturing of a gas well where gas flowback that is otherwise vented is captured, cleaned, and routed to the sales line.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Routed to a process or route to a process means the emissions are conveyed to any enclosed portion of a process unit where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the composition, moisture, or other limits set by the purchaser of the natural gas.

Sales line means pipeline, generally small in diameter, used to transport oil or gas from the well to a processing facility or a mainline pipeline.

Storage vessel means a stationary vessel or series of stationary vessels that are either manifolded together or are located at a single well site and that have potential for VOC emissions equal to or greater than 10 tpy.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A to part 60 of this chapter.

Total SO_2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

Underground storage tank means a storage tank stored below ground.

Well means an oil or gas well, a hole drilled for the purpose of producing oil or gas, or a well into which fluids are injected.

Well completion means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment.

Well completion operation means any well completion or well workover occurring at a gas wellhead affected facility.

Well site means the areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

TABLE 1 TO SUBPART OOOO OF PART 60—REQUIRED MINIMUM INITIAL SO_2 EMISSION REDUCTION EFFICIENCY (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \le X \le 5.0$	$5.0 < X \le 15.0$	$15.0 < X \le 300.0$	$X > 300.0$
$Y \ge 50$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller		
$20 \le Y < 50$	79.0	$88.5X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller		97.9
$10 \le Y < 20$	79.0	$88.5X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller	93.5	93.5
$Y < 10$	79.0	79.0	79.0	79.0

TABLE 2 TO SUBPART OOOO OF PART 60—REQUIRED MINIMUM SO_2 EMISSION REDUCTION EFFICIENCY (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \le X \le 5.0$	$5.0 < X \le 15.0$	$15.0 < X \le 300.0$	$X > 300.0$
$Y \ge 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller		
$20 \le Y < 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.9, whichever is smaller		97.5
$10 \le Y < 20$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
$Y < 10$	74.0	74.0	74.0	74.0

E = The sulfur emission rate expressed as elemental sulfur, kilograms per hour (kg/hr) [pounds per hour (lb/hr)], rounded to one decimal place.
R = The sulfur emission reduction efficiency achieved in percent, carried to one decimal place.
S = The sulfur production rate, kilograms per hour (kg/hr) [pounds per hour (lb/hr)], rounded to one decimal place.
X = The sulfur feed rate from the sweetening unit (*i.e.,* the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.
Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.
Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

TABLE 3 TO SUBPART OOOO OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOO

[As stated in § 60.5425, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.1	General applicability of the General Provisions	Yes.	
§ 60.2	Definitions	Yes.	Additional terms defined in § 60.5430.
§ 60.3	Units and abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and record keeping	Yes	Except that § 60.7 only applies as specified in § 60.5420(a).

TABLE 3 TO SUBPART OOOO OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOO—Continued

[As stated in § 60.5425, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.8	Performance tests	No	Performance testing is required for storage vessels as specified in 40 CFR part 63, subpart HH.
§ 60.9	Availability of information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No	Requirements are specified in subpart OOOO.
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§ 60.14	Modification	Yes.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	Yes.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	Yes.	
§ 60.19	General notification and reporting requirement	Yes.	

PART 63—[AMENDED]

8. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

9. Section 63.14 is amended by:

a. Adding paragraphs (b)(69), (b)(70), (b)(71) and (b)(72); and

b. Revising paragraph (i)(1) to read as follows:

§ 63.14 Incorporations by reference.

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(b) * * *

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(69) ASTM D1945–03(2010) Standard Test Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §§ 63.772 and 63.1282.

(70) ASTM D5504–08 Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§ 63.772 and 63.1282.

(71) ASTM D3588–98(2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, IBR approved for §§ 63.772 and 63.1282.

(72) ASTM D4891–89(2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, IBR approved for §§ 63.772 and 63.1282.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], issued August 31, 1981 IBR approved for §§ 63.309(k)(1)(iii), 63.771(e), 63.865(b), 63.1281(d), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), 63.11551(a)(2)(i)(C), 63.11646(a)(1)(iii), table 5 to subpart DDDDD of this part, and table 1 to subpart ZZZZZ of this part.

* * * * *

Subpart HH—[Amended]

10. Section 63.760 is amended by:

a. Revising paragraph (a)(1) introductory text;

b. Revising paragraph (a)(1)(iii);

c. Revising paragraph (a)(2);

d. Revising paragraph (b)(1)(ii);

e. Revising paragraph (f) introductory text;

f. Revising paragraph (f)(1);

g. Revising paragraph (f)(2); and

h. Adding paragraphs (f)(7), (f)(8), (f)(9) and (f)(10) to read as follows:

§ 63.760 Applicability and designation of affected source.

(a) * * *

(1) Facilities that are major or area sources of hazardous air pollutants (HAP) as defined in § 63.761. Emissions for major source determination purposes can be estimated using the maximum natural gas or hydrocarbon liquid throughput, as appropriate, calculated in paragraphs (a)(1)(i) through (iii) of this section. As an alternative to calculating the maximum natural gas or hydrocarbon liquid throughput, the owner or operator of a new or existing source may use the facility's design maximum natural gas or hydrocarbon liquid throughput to estimate the maximum potential emissions. Other means to determine the facility's major source status are allowed, provided the information is documented and recorded to the Administrator's satisfaction in accordance with § 63.10(b)(3). A facility that is determined to be an area source, but subsequently increases its emissions or its potential to emit above the major source levels, and becomes a major source, must comply thereafter with all provisions of this subpart applicable to a major source starting on the applicable compliance date specified in paragraph (f) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

* * * * *

(iii) The owner or operator shall determine the maximum values for other parameters used to calculate emissions as the maximum for the period over which the maximum natural gas or hydrocarbon liquid throughput is determined in accordance with paragraph (a)(1)(i)(A) or (B) of this section. Parameters, other than glycol circulation rate, shall be based on either highest measured values or annual average. For estimating maximum potential emissions from glycol dehydration units, the glycol circulation rate used in the calculation shall be the unit's maximum rate under its physical and operational design consistent with the definition of potential to emit in § 63.2.

(2) Facilities that process, upgrade, or store hydrocarbon liquids prior to the point where hydrocarbon liquids enter either the Organic Liquids Distribution (Non-gasoline) or Petroleum Refineries source categories.

* * * * *

(b) * * *

(1) * * *

(ii) Each storage vessel;

* * * * *

(f) The owner or operator of an affected major source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(1), (f)(2), and (f)(7) through (f)(10) of this section. The owner or operator of an affected area source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(3) through (f)(6) of this section.

(1) Except as specified in paragraphs (f)(7) through (10) of this section, the owner or operator of an affected major source, the construction or reconstruction of which commenced before February 6, 1998, shall achieve compliance with the applicable provisions of this subpart no later than June 17, 2002, except as provided for in § 63.6(i). The owner or operator of an area source, the construction or reconstruction of which commenced before February 6, 1998, that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply with this subpart 3 years after becoming a major source.

(2) Except as specified in paragraphs (f)(7) through (10) of this section, the owner or operator of an affected major source, the construction or reconstruction of which commences on or after February 6, 1998, shall achieve compliance with the applicable provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later. Area sources, other than production field facilities identified in (f)(9) of this section, the construction or reconstruction of which commences on or after February 6, 1998, that become major sources shall comply with the provisions of this standard immediately upon becoming a major source.

* * * * *

(7) Each affected small glycol dehydration unit and each storage vessel that is not a storage vessel with the potential for flash emissions located at a major source, that commenced construction before August 23, 2011 must achieve compliance no later than 3 years after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

(8) Each affected small glycol dehydration unit and each storage vessel that is not a storage vessel with the potential for flash emissions, both as defined in § 63.761, located at a major source, that commenced construction on or after August 23, 2011 must achieve compliance immediately upon initial startup or the date of publication of the final rule in the **Federal Register**, whichever is later.

(9) A production field facility, as defined in § 63.761, constructed before August 23, 2011 that was previously determined to be an area source but becomes a major source (as defined in paragraph 3 of the major source definition in § 63.761) on the date of publication of the final rule in the **Federal Register** must achieve compliance no later than 3 years after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

(10) Each large glycol dehydration unit, as defined in § 63.761, that has complied with the provisions of this subpart prior to August 23, 2011 by reducing its benzene emissions to less than 0.9 megagrams per year must achieve compliance no later than 90 days after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

* * * * *

11. Section 63.761 is amended by:

a. Adding, in alphabetical order, new definitions for the terms ''affirmative defense,'' ''BTEX,'' ''flare,'' ''large glycol dehydration units'' and ''small glycol dehydration units'';

b. Revising the definitions for ''associated equipment,'' ''facility,'' ''glycol dehydration unit baseline operations,'' and ''temperature monitoring device''; and

c. Revising paragraph (3) of the definition for ''major source'' to read as follows:

§ 63.761 Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

Associated equipment, as used in this subpart and as referred to in section 112(n)(4) of the Act, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the wellbore to the point of custody transfer, except glycol dehydration units and storage vessels.

* * * * *

BTEX means benzene, toluene, ethyl benzene and xylene.

* * * * *

Facility means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored; or where natural gas is processed, upgraded, or stored. For the purpose of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

* * * * *

Flare means a thermal oxidation system using an open flame (*i.e.,* without enclosure).

* * * * *

Glycol dehydration unit baseline operations means operations representative of the large glycol dehydration unit operations as of June 17, 1999 and the small glycol dehydrator unit operations as of August 23, 2011. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (*i.e.,* at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

* * * * *

Large glycol dehydration unit means a glycol dehydration unit with an actual annual average natural gas flowrate equal to or greater than 85 thousand standard cubic meters per day and actual annual average benzene emissions equal to or greater than 0.90

Mg/yr, determined according to § 63.772(b).

* * * * *

Major source * * *

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

* * * * *

Small glycol dehydration unit means a glycol dehydration unit, located at a major source, with an actual annual average natural gas flowrate less than 85 thousand standard cubic meters per day or actual annual average benzene emissions less than 0.90 Mg/yr, determined according to § 63.772(b).

* * * * *

Temperature monitoring device means an instrument used to monitor temperature and having a minimum accuracy of ± 1 percent of the temperature being monitored expressed in °C, or ± 2.5 °C, whichever is greater. The temperature monitoring device may measure temperature in degrees Fahrenheit or degrees Celsius, or both.

* * * * *

12. Section 63.762 is revised to read as follows:

§ 63.762 Startups and shutdowns.

(a) The provisions set forth in this subpart shall apply at all times.

(b) The owner or operator shall not shut down items of equipment that are required or utilized for compliance with the provisions of this subpart during times when emissions are being routed to such items of equipment, if the shutdown would contravene requirements of this subpart applicable to such items of equipment. This paragraph does not apply if the owner or operator must shut down the equipment to avoid damage due to a contemporaneous startup or shutdown, of the affected source or a portion thereof.

(c) During startups and shutdowns, the owner or operator shall implement measures to prevent or minimize excess emissions to the maximum extent practical.

(d) In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined in 40 CFR 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) *Notification.* The owner or operator of the affected source experiencing exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in this subpart to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

13. Section 63.764 is amended by:

a. Revising paragraph (c)(2) introductory text;

b. Revising paragraph (e)(1) introductory text;

c. Revising paragraph (i); and

d. Adding paragraph (j) to read as follows:

§ 63.764 General standards.

* * * * *

(c) * * *

(2) For each storage vessel subject to this subpart, the owner or operator shall comply with the requirements specified in paragraphs (c)(2)(i) through (iii) of this section.

* * * * *

(e) *Exemptions.* (1) The owner or operator of an area source is exempt from the requirements of paragraph (d) of this section if the criteria listed in paragraph (e)(1)(i) or (ii) of this section are met, except that the records of the determination of these criteria must be maintained as required in § 63.774(d)(1).

* * * * *

(i) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this standard to fail to take action to repair the leak(s) within the specified time. If action is taken to repair the leak(s) within the specified time, failure of that action to successfully repair the leak(s) is not a violation of this standard. However, if the repairs are unsuccessful, and a leak is detected, the owner or operator shall take further action as required by the applicable provisions of this subpart.

(j) At all times the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

14. Section 63.765 is amended by:

a. Revising paragraph (a);

b. Revising paragraph (b)(1);

c. Revising paragraph (c)(2); and

d. Revising paragraph (c)(3) to read as follows:

§ 63.765 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit subject to this subpart that must be controlled for air emissions as specified in either paragraph (c)(1)(i) or paragraph (d)(1)(i) of § 63.764.

(b) * * *

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i), (ii), or (iii) of this section.

(i) The owner or operator of a large glycol dehydration unit, as defined in § 63.761, shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d).

(ii) The owner or operator of a glycol dehydration unit located at an area source, that must be controlled as specified in § 63.764(d)(1)(i), shall connect the process vent to a control device or combination of control devices through a closed-vent system and the outlet benzene emissions from the control device(s) shall be reduced to a level less than 0.90 megagrams per year. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d), except that the performance levels specified in § 63.771(d)(1)(i) and (ii) do not apply.

(iii) You must limit BTEX emissions from each small glycol dehydration unit process vent, as defined in § 63.761, to the limit determined in Equation 1 of this section. The limit must be met in accordance with one of the alternatives specified in paragraphs (b)(1)(iii)(A) through (D) of this section.

$$EL_{BTEX} = 1.10x10^{-4} * Throughput * C_{i,BTEX} * 365\,\frac{days}{yr} * \frac{1\,Mg}{1x10^{6}\,grams}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

1.10×10^{-4} = BTEX emission limit, grams BTEX/standard cubic meter = ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day;

$C_{i,BTEX}$ = BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

(A) Connect the process vent to a control device or combination of control devices through a closed-vent system. The closed vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(f).

(B) Meet the emissions limit through process modifications in accordance with the requirements specified in § 63.771(e).

(C) Meet the emissions limit for each small glycol dehydration unit using a combination of process modifications and one or more control devices through the requirements specified in paragraphs (b)(1)(iii)(A) and (B) of this section.

(D) Demonstrate that the emissions limit is met through actual uncontrolled operation of the small glycol dehydration unit. Document operational parameters in accordance with the requirements specified in § 63.771(e) and emissions in accordance with the requirements specified in § 63.772(b)(2).

* * * * *

(c) * * *

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the large glycol dehydration unit process vent are reduced by 95.0 percent through process modifications, or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.771(e).

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraph (c)(3)(i), (ii), or (iii) of this section, through the installation and operation of controls as specified in paragraph (b)(1) of this section.

(i) For any large glycol dehydration unit, HAP emissions are reduced by 95.0 percent or more.

(ii) For area source dehydration units, benzene emissions are reduced to a level less than 0.90 megagrams per year.

(iii) For each small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated by paragraph (b)(1)(iii) of this section.

15. Section 63.766 is amended by:

a. Revising paragraph (a);

b. Revising paragraph (b) introductory text;

c. Revising paragraph (b)(1); and

d. Revising paragraph (d) to read as follows:

§ 63.766 Storage vessel standards.

(a) This section applies to each storage vessel (as defined in § 63.761) subject to this subpart.

(b) The owner or operator of a storage vessel (as defined in § 63.761) shall comply with one of the control requirements specified in paragraphs (b)(1) and (2) of this section.

(1) The owner or operator shall equip the affected storage vessel with a cover that is connected, through a closed-vent system that meets the conditions specified in § 63.771(c), to a control device or a combination of control devices that meets any of the conditions specified in § 63.771(d). The cover shall be designed and operated in accordance with the requirements of § 63.771(b).

* * * * *

(d) This section does not apply to storage vessels for which the owner or operator is subject to and controlled under the requirements specified in 40

CFR part 60, subpart Kb; or the requirements specified under 40 CFR part 63 subparts G or CC.

16. Section 63.769 is amended by:

a. Revising paragraph (b);

b. Revising paragraph (c) introductory text; and

b. Revising paragraph (c)(8) to read as follows:

§ 63.769 Equipment leak standards.

* * * * *

(b) This section does not apply to ancillary equipment and compressors for which the owner or operator is subject to and controlled under the requirements specified in subpart H of this part; or the requirements specified in 40 CFR part 60, subpart KKK.

(c) For each piece of ancillary equipment and each compressor subject to this section located at an existing or new source, the owner or operator shall meet the requirements specified in 40 CFR part 61, subpart V, §§ 61.241 through 61.247, except as specified in paragraphs (c)(1) through (8) of this section, except for valves subject to § 61.247–2(b) a leak is detected if an instrument reading of 500 ppm or greater is measured.

* * * * *

(8) Flares, as defined in § 63.761, used to comply with this subpart shall comply with the requirements of § 63.11(b).

17. Section 63.771 is amended by:

a. Revising paragraph (c)(1) introductory text;

b. Revising the heading of paragraph (d);

c. Adding paragraph (d) introductory text;

d. Revising paragraph (d)(1)(i) introductory text;

e. Revising paragraph (d)(1)(i)(C);

f. Revising paragraph (d)(1)(ii);

g. Revising paragraph (d)(1)(iii);

h. Revising paragraph (d)(4)(i);

i. Revising paragraph (d)(5)(i);

j. Revising paragraph (e)(2);

k. Revising paragraph (e)(3) introductory text;

l. Revising paragraph (e)(3)(ii); and

m. Adding paragraph (f) to read as follows:

§ 63.771 Control equipment requirements.

* * * * *

(c) *Closed-vent system requirements.* (1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in an emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

* * * * *

(d) *Control device requirements for sources except small glycol dehydration units.* Owners and operators of small glycol dehydration units, shall comply with the control device requirements in paragraph (f) of this section.

(1) * * *

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated in accordance with one of the following performance requirements:

* * * * *

(C) For a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 63.772(e), operates at a minimum temperature of 760 degrees C.

* * * * *

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.772(e).

(iii) A flare, as defined in § 63.761, that is designed and operated in accordance with the requirements of § 63.11(b).

* * * * *

(4) * * *

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the HAP emissions unit or units through the closed-vent system to the control device, as required under § 63.765, § 63.766, and § 63.769. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

* * * * *

(5) * * *

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon adsorption system. Records identifying the schedule for replacement and records of each carbon replacement shall be maintained as required in § 63.774(b)(7)(ix). The schedule for replacement shall be submitted with the Notification of Compliance Status Report as specified in § 63.775(d)(5)(iv). Each carbon replacement must be reported in the Periodic Reports as specified in § 63.772(e)(2)(xii).

* * * * *

(e) * * *

(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, or BTEX limit determined in § 63.765(b)(1)(iii), as applicable, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the emission reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent or, if applicable, the BTEX limit determined in § 63.765(b)(1)(iii) for the small glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including but not limited to changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall emission reduction due to process modifications.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.765(b)(1)(iii), as applicable, using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.765(b)(1)(iii), as applicable, using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (e)(3)(ii) of this section.

* * * * *

(ii) The owner or operator shall comply with the control device requirements specified in paragraph (d) or (f) of this section, as applicable, except that the emission reduction or limit achieved shall be the emission reduction or limit specified for the control device(s) in paragraph (e)(2) of this section.

(f) *Control device requirements for small glycol dehydration units.* (1) The control device used to meet BTEX the emission limit calculated in § 63.765(b)(1)(iii) shall be one of the control devices specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.772(e). If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.772(e); or

(iii) A flare, as defined in § 63.761, that is designed and operated in accordance with the requirements of § 63.11(b).

(2) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.773(d), the owner or operator shall demonstrate compliance according to the requirements of either § 63.772(f) or (h).

(3) For each carbon adsorption system used as a control device to meet the requirements of paragraph (f)(1)(ii) of this section, the owner or operator shall manage the carbon as required under (d)(5)(i) and (ii) of this section.

18. Section 63.772 is amended by:

a. Revising paragraph (b) introductory text;

b. Revising paragraph (b)(1)(ii);

c. Revising paragraph (b)(2);

d. Adding paragraph (d);

e. Revising paragraph (e) introductory text;

f. Revising paragraphs (e)(1)(i) through (v);

g. Revising paragraph (e)(2);

h. Revising paragraph (e)(3) introductory text;

i. Revising paragraph (e)(3)(i)(B);

j. Revising paragraph (e)(3)(iv)(C)(*1*);

k. Adding paragraphs (e)(3)(v) and (vi);

l. Revising paragraph (e)(4) introductory text;

m. Revising paragraph (e)(4)(i);

n. Revising paragraph (e)(5);

o. Revising paragraph (f) introductory text;

p. Adding paragraphs (f)(2) through (f)(6);

q. Revising paragraph (g) introductory text;

r. Revising paragraph (g)(1) and paragraph (g)(2) introductory text;

s. Revising paragraph (g)(2)(iii);

t. Revising paragraph (g)(3);

u. Adding paragraph (h); and

v. Adding paragraph (i) to read as follows:

§ 63.772 Test methods, compliance procedures, and compliance demonstrations.

* * * * *

(b) *Determination of glycol dehydration unit flowrate, benzene emissions, or BTEX emissions.* The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate, benzene emissions, or BTEX emissions.

(1) * * *

(ii) The owner or operator shall document, to the Administrator's satisfaction, the actual annual average natural gas flowrate to the glycol dehydration unit.

(2) The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (b)(2)(i) or (b)(2)(ii) of this section. Emissions shall be determined either uncontrolled, or with federally enforceable controls in place.

(i) The owner or operator shall determine actual average benzene or BTEX emissions using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1); or

(ii) The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement using the methods in § 63.772(a)(1)(i) or (ii), or an alternative method according to § 63.7(f). Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

* * * * *

(d) *Test procedures and compliance demonstrations for small glycol dehydration units.* This paragraph applies to the test procedures for small dehydration units.

(1) If the owner or operator is using a control device to comply with the emission limit in § 63.765(b)(1)(iii), the requirements of paragraph (e) of this section apply. Compliance is demonstrated using the methods specified in paragraph (f) of this section.

(2) If no control device is used to comply with the emission limit in § 63.765(b)(1)(iii), the owner or operator must determine the glycol dehydration unit BTEX emissions as specified in paragraphs (d)(2)(i) through (iii) of this section. Compliance is demonstrated if the BTEX emissions determined as specified in paragraphs (d)(2)(i) through (iii) are less than the emission limit calculated using the equation in § 63.765(b)(1)(iii).

(i) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites at the outlet of the glycol dehydration unit process vent. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(ii) The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(iii) The BTEX emissions from the outlet of the glycol dehydration unit process vent shall be determined using the procedures specified in paragraph (e)(3)(v) of this section. As an alternative, the mass rate of BTEX at the outlet of the glycol dehydration unit process vent may be calculated using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and shall be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1). When the BTEX mass rate is calculated for glycol dehydration units using the model GRI–GLYCalc™, all BTEX measured by Method 18, 40 CFR part 60, appendix A, shall be summed.

(e) *Control device performance test procedures.* This paragraph applies to the performance testing of control devices. The owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1) using a performance test as specified in paragraph (e)(3) of this section. Owners or operators using a condenser have the option to use a design analysis as specified in paragraph (e)(4) of this section. The owner or operator may elect to use the alternative procedures in paragraph (e)(5) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent. As an alternative to conducting a performance test under this section for combustion control devices, a control device that can be demonstrated to meet the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1) through a performance test conducted by the manufacturer, as specified in paragraph (h) of this section can be used.

(1) * * *

(i) Except as specified in paragraph (e)(2) of this section, a flare, as defined in § 63.761, that is designed and operated in accordance with § 63.11(b);

(ii) Except for control devices used for small glycol dehydration units, a boiler or process heater with a design heat input capacity of 44 megawatts or greater;

(iii) Except for control devices used for small glycol dehydration units, a boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel;

(iv) Except for control devices used for small glycol dehydration units, a boiler or process heater burning hazardous waste for which the owner or operator has either been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H; or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(v) Except for control devices used for small glycol dehydration units, a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O; or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

* * * * *

(2) An owner or operator shall design and operate each flare, as defined in § 63.761, in accordance with the requirements specified in § 63.11(b) and the compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

(3) For a performance test conducted to demonstrate that a control device meets the requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1), the owner or operator shall use the test methods and procedures specified in paragraphs (e)(3)(i) through (v) of this section. The initial and periodic performance tests shall be conducted according to the schedule specified in paragraph (e)(3)(vi) of this section.

(i) * * *

(B) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.765(b)(1)(iii), or the BTEX emission limit specified in § 63.771(f)(1) the sampling site shall be located at the outlet of the combustion device.

* * * * *

(iv) * * *

(C) * * *

(*1*) The emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B, 40 CFR part 60, appendix A, shall be used to determine the oxygen concentration. The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

* * * * *

(v) To determine compliance with the BTEX emission limit specified in § 63.771(f)(1) the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420–99 (2004), as specified in § 63.772(a)(1)(ii); or any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. The following procedures shall be used to calculate BTEX emissions:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The mass rate of BTEX (E_o) shall be computed using the equations and procedures specified in paragraphs (e)(3)(v)(B)(*1*) and (*2*) of this section.

(*1*) The following equation shall be used:

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj}M_{oj}\right)Q_o$$

Where:

E_o= Mass rate of BTEX at the outlet of the control device, dry basis, kilogram per hour.

C_{oj}= Concentration of sample component j of the gas stream at the outlet of the control device, dry basis, parts per million by volume.

M_{oj}= Molecular weight of sample component j of the gas stream at the outlet of the control device, gram/gram-mole.

Q_o= Flowrate of gas stream at the outlet of the control device, dry standard cubic meter per minute.

K_2= Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees C.

n = Number of components in sample.

(*2*) When the BTEX mass rate is calculated, only BTEX compounds measured by Method 18, 40 CFR part 60, appendix A, or ASTM D6420–99 (2004) as specified in § 63.772(a)(1)(ii), shall be summed using the equations in paragraph (e)(3)(v)(B)(*1*) of this section.

(vi) The owner or operator shall conduct performance tests according to the schedule specified in paragraphs (e)(3)(vi)(A) and (B) of this section.

(A) An initial performance test shall be conducted within 180 days after the compliance date that is specified for each affected source in § 63.760(f)(7) through (8), except that the initial performance test for existing combustion control devices at existing major sources shall be conducted no later than 3 years after the date of publication of the final rule in the **Federal Register**. If the owner or operator of an existing combustion control device at an existing major source chooses to replace such device with a control device whose model is tested under § 63.772(h), then the newly installed device shall comply with all provisions of this subpart no later than 3 years after the date of publication of the final rule in the **Federal Register**. The performance test results shall be submitted in the Notification of Compliance Status Report as required in § 63.775(d)(1)(ii).

(B) Periodic performance tests shall be conducted for all control devices required to conduct initial performance tests except as specified in paragraphs (e)(3)(vi)(B)(*1*) and (*2*) of this section. The first periodic performance test shall be conducted no later than 60 months after the initial performance test required in paragraph (e)(3)(vi)(A) of this section. Subsequent periodic performance tests shall be conducted at intervals no longer than 60 months following the previous periodic performance test or whenever a source desires to establish a new operating limit. The periodic performance test results must be submitted in the next Periodic Report as specified in § 63.775(e)(2)(xi). Combustion control devices meeting the criteria in either paragraph (e)(3)(vi)(B)(*1*) or (*2*) of this section are not required to conduct periodic performance tests.

(*1*) A control device whose model is tested under, and meets the criteria of, § 63.772(h), or

(*2*) A combustion control device tested under § 63.772(e) that meets the outlet TOC or HAP performance level specified in § 63.771(d)(1)(i)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC or HAP performance level.

(4) For a condenser design analysis conducted to meet the requirements of § 63.771(d)(1), (e)(3)(ii), or (f)(1), the owner or operator shall meet the requirements specified in paragraphs (e)(4)(i) and (e)(4)(ii) of this section. Documentation of the design analysis shall be submitted as a part of the Notification of Compliance Status Report as required in § 63.775(d)(1)(i).

(i) The condenser design analysis shall include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet. As an alternative to the condenser design analysis, an owner or operator may elect to use the procedures specified in paragraph (e)(5) of this section.

* * * * *

(5) As an alternative to the procedures in paragraph (e)(4)(i) of this section, an owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(f) *Compliance demonstration for control device performance requirements.* This paragraph applies to the demonstration of compliance with the control device performance requirements specified in § 63.771(d)(1)(i), (e)(3) and (f)(1). Compliance shall be demonstrated using the requirements in paragraphs (f)(1) through (3) of this section. As an alternative, an owner or operator that installs a condenser as the control device to achieve the requirements specified in § 63.771(d)(1)(ii), (e)(3) or (f)(1) may demonstrate compliance according to paragraph (g) of this section. An owner or operator may switch between compliance with paragraph (f) of this section and compliance with paragraph (g) of this section only after at least 1 year of operation in compliance with the selected approach. Notification of such a change in the compliance method shall be reported in the next Periodic Report, as required in § 63.775(e), following the change.

* * * * *

(2) The owner or operator shall calculate the daily average of the applicable monitored parameter in accordance with § 63.773(d)(4) except that the inlet gas flow rate to the control device shall not be averaged.

(3) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (f)(2) of this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under paragraph (f)(1) of this section. For inlet gas flow rate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under § 63.772(h).

(4) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), the CMS required in § 63.773(d) must be operated at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Monitoring system repairs are required to be completed in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(5) Data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. All the data collected during all other required data collection periods must be used in assessing the operation of the control device and associated control system.

(6) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

(g) *Compliance demonstration with percent reduction or emission limit performance requirements—condensers.* This paragraph applies to the demonstration of compliance with the performance requirements specified in § 63.771(d)(1)(ii),(e)(3) or (f)(1) for condensers. Compliance shall be demonstrated using the procedures in paragraphs (g)(1) through (3) of this section.

(1) The owner or operator shall establish a site-specific condenser performance curve according to § 63.773(d)(5)(ii). For sources required to meet the BTEX limit in accordance with § 63.771(e) or (f)(1) the owner or operator shall identify the minimum percent reduction necessary to meet the BTEX limit.

(2) Compliance with the requirements in § 63.771(d)(1)(ii),(e)(3) or (f)(1) shall be demonstrated by the procedures in paragraphs (g)(2)(i) through (iii) of this section.

* * * * *

(iii) Except as provided in paragraphs (g)(2)(iii)(A) and (B) of this section, at the end of each operating day, the owner or operator shall calculate the 365-day average HAP, or BTEX, emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (g)(2)(ii) of this section for the preceding 365 operating days. If the owner or operator uses a combination of process modifications and a condenser in accordance with the requirements of § 63.771(e), the 365-day average HAP, or BTEX, emission reduction shall be calculated using the emission reduction achieved through process modifications and the condenser efficiency as determined in paragraph (g)(2)(ii) of this section, both for the previous 365 operating days.

(A) After the compliance dates specified in § 63.760(f), an owner or operator with less than 120 days of data for determining average HAP, or BTEX, emission reduction, as appropriate, shall calculate the average HAP, or BTEX emission reduction, as appropriate, for the first 120 days of operation after the compliance dates. For sources required to meet the overall 95.0 percent reduction requirement, compliance is achieved if the 120-day average HAP emission reduction is equal to or greater than 90.0 percent. For sources required to meet the BTEX limit under § 63.765(b)(1)(iii), compliance is achieved if the average BTEX emission reduction is at least 95.0 percent of the required 365-day value identified under paragraph (g)(1) of this section (*i.e.,* at least 76.0 percent if the 365-day design value is 80.0 percent).

(B) After 120 days and no more than 364 days of operation after the compliance dates specified in § 63.760(f), the owner or operator shall calculate the average HAP emission reduction as the HAP emission reduction averaged over the number of days between the current day and the applicable compliance date. For sources required to meet the overall 95.0-percent reduction requirement, compliance with the performance requirements is achieved if the average HAP emission reduction is equal to or greater than 90.0 percent. For sources required to meet the BTEX limit under § 63.765(b)(1)(iii), compliance is achieved if the average BTEX emission reduction is at least 95.0 percent of the required 365-day value identified under paragraph (g)(1) of this section (*i.e.,* at least 76.0 percent if the 365-day design value is 80.0 percent).

(3) If the owner or operator has data for 365 days or more of operation, compliance is achieved based on the applicable criteria in paragraphs (g)(3)(i) or (ii) of this section.

(i) For sources meeting the HAP emission reduction specified in § 63.771(d)(1)(ii) or (e)(3) the average HAP emission reduction calculated in paragraph (g)(2)(iii) of this section is equal to or greater than 95.0 percent.

(ii) For sources required to meet the BTEX limit under § 63.771(e)(3) or (f)(1), compliance is achieved if the average BTEX emission reduction calculated in paragraph (g)(2)(iii) of this section is equal to or greater than the minimum percent reduction identified in paragraph (g)(1) of this section.

* * * * *

(h) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer shall demonstrate that a specific model of control device achieves the performance requirements in (h)(7) of this section by conducting a performance test as specified in paragraphs (h)(2) through (6) of this section.

(2) Performance testing shall consist of three one-hour (or longer) test runs for each of the four following firing rate settings making a total of 12 test runs per test. Propene (propylene) gas shall be used for the testing fuel. All fuel analyses shall be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at 0 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 100 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 0 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures shall be tested simultaneously and with all burners operational. Results shall be reported for the each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data shall be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. Data shall be submitted with the test report in accordance with paragraph (8)(iii) of this section.

(4) Inlet testing shall be conducted as specified in paragraphs (h)(4)(i) through (iii) of this section.

(i) The fuel flow metering system shall be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure fuel flow rate at the control device inlet location. The fitting for filling fuel sample containers shall be located a minimum of 8 pipe diameters upstream of any inlet fuel flow monitoring meter.

(ii) Inlet flow rate shall be determined using Method 2A, 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) Inlet fuel sampling shall be conducted in accordance with the criteria in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) At the inlet fuel sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 1 hour period. Filling shall be conducted as specified in the following:

(*1*) Open the canister sampling valve at the beginning of the total hydrocarbon (THC) test, and close the canister at the end of the THC test.

(*2*) Fill one canister for each THC test run.

(*3*) Label the canisters individually and record on a chain of custody form.

(B) Each fuel sample shall be analyzed using the following methods. The results shall be included in the test report.

(*1*) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03.

(*2*) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03.

(*3*) Carbonyl sulfide, carbon disulfide plus mercaptans using ASTM D5504.

(*4*) Higher heating value using ASTM D3588–98 or ASTM D4891–89.

(5) Outlet testing shall be conducted in accordance with the criteria in paragraphs (h)(5)(i) through (v) of this section.

(i) Sampling and flowrate measured in accordance with the following:

(A) The outlet sampling location shall be a minimum of 4 equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports shall be used.

(B) Flow rate shall be measured using Method 1, 40 CFR part 60, Appendix 1, for determining flow measurement traverse point location; and Method 2, 40 CFR part 60, Appendix 1, shall be used to measure duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer shall be used to obtain an accurate flow profile.

(ii) Molecular weight shall be determined as specified in paragraphs (h)(4)(iii)(B), (h)(5)(ii)(A), and (h)(5)(ii)(B) of this section.

(A) An integrated bag sample shall be collected during the Method 4, 40 CFR part 60, Appendix A, moisture test. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the following criteria:

(*1*) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(*2*) The sampling line shall be purged with stack gas before opening the valve and beginning to fill the bag.

(*3*) The bag contents shall be kneaded or otherwise vigorously mixed prior to the GC analysis.

(*4*) The GC–TCD calibration procedure in Method 3C, 40 CFR part 60, Appendix A, shall be modified by using EPAAlt–045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, the initial calibration using at least three concentration levels shall be repeated.

(B) Report the molecular weight of: O_2, CO_2, methane (CH4), and N_2 and include in the test report submitted under § 63.775(d)(iii). Moisture shall be determined using Method 4, 40 CFR part 60, Appendix A. Traverse both ports with the Method 4, 40 CFR part 60, Appendix A, sampling train during each test run. Ambient air shall not be introduced into the Method 3C, 40 CFR part 60, Appendix A, integrated bag sample during the port change.

(iii) Carbon monoxide shall be determined using Method 10, 40 CFR part 60, Appendix A. The test shall be run at the same time and with the sample points used for the EPA Method 25A, 40 CFR part 60, Appendix A, testing. An instrument range of 0–10 per million by volume-dry (ppmvd) shall be used.

(iv) Visible emissions shall be determined using Method 22, 40 CFR part 60, Appendix A. The test shall be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, will be taken once per test run and the four photos included in the test report.

(6) Total hydrocarbons (THC) shall be determined as specified by the following criteria:

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, Appendix A, except the option for locating the probe in the center 10 percent of the stack shall not be allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during the testing.

(ii) A valid test shall consist of three Method 25A, 40 CFR part 60, Appendix A, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases will be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121 (or more recent if updated since 1999).

(v) THC measurements shall be reported in terms of ppmvw as propane.

(vi) THC results shall be corrected to 3 percent CO_2, as measured by Method 3C, 40 CFR part 60, Appendix A.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(7) Performance test criteria:

(i) The control device model tested must meet the criteria in paragraphs (h)(7)(i)(A) through (C) of this section:

(A) Method 22, 40 CFR part 60, Appendix A, results under paragraph (h)(5)(v) of this section with no indication of visible emissions, and

(B) Average Method 25A, 40 CFR part 60, Appendix A, results under paragraph (h)(6) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2, and

(C) Average CO emissions determined under paragraph (h)(5)(iv) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(ii) The manufacturer shall determine a maximum inlet gas flow rate which shall not be exceeded for each control device model to achieve the criteria in paragraph (h)(7)(i) of this section.

(iii) A control device meeting the criteria in paragraphs (h)(7)(i)(A) through (C) of this section will have demonstrated a destruction efficiency of 98.0 percent for HAP regulated under this subpart.

(8) The owner or operator of a combustion control device model tested under this section shall submit the information listed in paragraphs (h)(8)(i) through (iii) of this section in the test report required under § 63.775(d)(1)(iii).

(i) Full schematic of the control device and dimensions of the device components.

(ii) Design net heating value (minimum and maximum) of the device.

(iii) Test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flow rate.

(iv) Air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (h)(8)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold pressure.

(I) Pilot flame sensor.

(J) Pilot flame design fuel and fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report shall include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated with test times and calibration values.

(i) *Compliance demonstration for combustion control devices—manufacturers' performance test.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (h) of this section. Owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1), by installing a device tested under paragraph (h) of this section and complying with the following criteria:

(1) The inlet gas flow rate shall meet the range specified by the manufacturer. Flow rate shall be measured as specified in § 63.773(d)(3)(i)(H)(*1*).

(2) A pilot flame shall be present at all times of operation. The pilot flame shall be monitored in accordance with § 63.773(d)(3)(i)(H)(*2*).

(3) Devices shall be operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. A visible emissions test using Method 22, 40 CFR part 60, Appendix A, shall be performed monthly. The observation period shall be 2 hours and shall be used according to Method 22.

(4) Compliance with the operating parameter limit is achieved when the following criteria are met:

(i) The inlet gas flow rate monitored under paragraph (i)(1) of this section is equal to or below the maximum established by the manufacturer; and

(ii) The pilot flame is present at all times; and

(iii) During the visible emissions test performed under paragraph (i)(3) of this section the duration of visible emissions does not exceed a total of 5 minutes during the observation period. Devices failing the visible emissions test shall follow the requirements in paragraphs (i)(4)(iii)(A) and (B) of this section.

(A) Following the first failure, the fuel nozzle(s) and burner tubes shall be replaced.

(B) If, following replacement of the fuel nozzle(s) and burner tubes as specified in paragraph (i)(4)(iii)(A), the visible emissions test is not passed in the next scheduled test, either a performance test shall be performed under paragraph (e) of this section, or the device shall be replaced with another control device whose model was tested, and meets, the requirements in paragraph (h) of this section.

19. Section 63.773 is amended by:

a. Adding paragraph (b);

b. Revising paragraph (d)(1) introductory text;

c. Revising paragraph (d)(1)(ii) and adding paragraphs (d)(1)(iii) and (iv);

d. Revising paragraphs (d)(2)(i) and (d)(2)(ii);

e. Revising paragraphs (d)(3)(i)(A) and (B);

f. Revising paragraphs (d)(3)(i)(D) and (E);

g. Revising paragraphs (d)(3)(i)(F)(*1*) and (*2*);

h. Revising paragraph (d)(3)(i)(G);

i. Adding paragraph (d)(3)(i)(H);

j. Revising paragraph (d)(4);

k. Revising paragraph (d)(5)(i);

l. Revising paragraphs (d)(5)(ii)(A) through (C);

m. Revising paragraphs (d)(6)(ii) and (iii);

n. Adding paragraph (d)(6)(vi);

o. Revising paragraph (d)(8)(i)(A); and

p. Revising paragraph (d)(8)(ii) to read as follows:

§ 63.773 Inspection and monitoring requirements.

* * * * *

(b) The owner or operator of a control device whose model was tested under § 63.772(h) shall develop an inspection and maintenance plan for each control device. At a minimum, the plan shall contain the control device manufacturer's recommendations for ensuring proper operation of the device. Semi-annual inspections shall be conducted for each control device with maintenance and replacement of control device components made in accordance with the plan.

* * * * *

(d) *Control device monitoring requirements.* (1) For each control device, except as provided for in paragraph (d)(2) of this section, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of paragraphs (d)(3) through (9) of this section. Owners or operators that install and operate a flare in accordance with § 63.771(d)(1)(iii) or (f)(1)(iii) are exempt from the requirements of paragraphs (d)(4) and (5) of this section. The continuous monitoring system shall be designed and operated so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 63.771(d), (e)(3) or (f)(1). Each continuous parameter monitoring system shall meet the following specifications and requirements:

* * * * *

(ii) A site-specific monitoring plan must be prepared that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraph (d) of this section and in § 63.8(d). Each CPMS must be installed, calibrated, operated, and maintained in accordance with the procedures in your approved site-specific monitoring plan. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (d)(1)(ii)(A) through (E) of this section in your site-specific monitoring plan.

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(B) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(C) Equipment performance checks, system accuracy audits, or other audit procedures;

(D) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (c)(3); and

(E) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(iii) The owner or operator must conduct the CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(iv) The owner or operator must conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

(2) * * *

(i) Except for control devices for small glycol dehydration units, a boiler or process heater in which all vent streams are introduced with the primary fuel or is used as the primary fuel; or

(ii) Except for control devices for small glycol dehydration units, a boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) * * *

(i) * * *

(A) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 63.772(e) that the combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

(B) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations and have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

* * * * *

(D) For a boiler or process heater a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

(E) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.8 degrees C, whichever value is greater. The temperature sensor shall be installed at a location in the exhaust vent stream from the condenser.

(F) * * *

(*1*) A continuous parameter monitoring system to measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. The mechanical connections for leakage must be checked at least every month, and a visual inspection must be performed at least every 3 months of all components of the flow CPMS for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow CPMS is not equipped with a redundant flow sensor; and

(*2*) A continuous parameter monitoring system to measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and to measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater.

(G) For a nonregenerative-type carbon adsorption system, the owner or operator shall monitor the design carbon replacement interval established using a performance test performed in accordance with § 63.772(e)(3) shall be based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device model whose model is tested under § 63.772(h):

(*1*) A continuous monitoring system that measures gas flow rate at the inlet to the control device. The monitoring instrument shall have an accuracy of plus or minus 2 percent or better.

(*2*) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

* * * * *

(4) Using the data recorded by the monitoring system, except for inlet gas flow rate, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(5) * * *

(i) The owner or operator shall establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1). Each minimum or maximum operating parameter value shall be established as follows:

(A) If the owner or operator conducts performance tests in accordance with the requirements of § 63.772(e)(3) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(B) If the owner or operator uses a condenser design analysis in accordance with the requirements of § 63.772(e)(4) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the condenser design analysis and may be supplemented by the condenser manufacturer's recommendations.

(C) If the owner or operator operates a control device where the performance test requirement was met under § 63.772(h) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the maximum inlet gas flow rate shall be established based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(ii) * * *

(A) If the owner or operator conducts a performance test in accordance with the requirements of § 63.772(e)(3) to demonstrate that the condenser achieves the applicable performance requirements in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the condenser performance curve shall be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.772(e)(4)(i) to demonstrate that the condenser achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the condenser performance curve shall be based on the condenser design analysis and may be supplemented by the control device manufacturer's recommendations.

(C) As an alternative to paragraph (d)(5)(ii)(B) of this section, the owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

* * * * *

(6) * * *

(ii) For sources meeting § 63.771(d)(1)(ii), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than 95.0 percent. For sources meeting § 63.771(f)(1), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than 95.0 percent of the identified 365-day required percent reduction.

(iii) For sources meeting § 63.771(d)(1)(ii), if an owner or operator has less than 365 days of data, an excursion occurs when the average condenser efficiency calculated according to the procedures specified in § 63.772(g)(2)(iii)(A) or (B) is less than 90.0 percent. For sources meeting § 63.771(d)(1)(ii), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than the identified 365-day required percent reduction.

* * * * *

(vi) For control device whose model is tested under § 63.772(h) an excursion occurs when:

(A) The inlet gas flow rate exceeds the maximum established during the test conducted under § 63.772(h).

(B) Failure of the monthly visible emissions test conducted under § 63.772(i)(3) occurs.

* * * * *

(8) * * *

(i) * * *

(A) During a malfunction when the affected facility is operated during such period in accordance with § 63.6(e)(1); or

* * * * *

(ii) For each control device, or combinations of control devices installed on the same emissions unit, one excused excursion is allowed per semiannual period for any reason. The initial semiannual period is the 6-month reporting period addressed by the first Periodic Report submitted by the owner or operator in accordance with § 63.775(e) of this subpart.

* * * * *

20. Section 63.774 is amended by:

a. Revising paragraph (b)(3) introductory text;

b. Removing and reserving paragraph (b)(3)(ii);

c. Revising paragraph (b)(4)(ii) introductory text;

d. Adding paragraph (b)(4)(ii)(C);

e. Adding paragraph (b)(7)(ix); and

f. Adding paragraphs (g) through (i) to read as follows:

§ 63.774 Recordkeeping requirements.

* * * * *

(b) * * *

(3) Records specified in § 63.10(c) for each monitoring system operated by the owner or operator in accordance with the requirements of § 63.773(d). Notwithstanding the requirements of § 63.10(c), monitoring data recorded during periods identified in paragraphs (b)(3)(i) through (b)(3)(iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating or failed to collect required data.

* * * * *

(ii) [Reserved]

* * * * *

(4) * * *

(ii) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.773(d)(4) of this subpart, except as specified in paragraphs (b)(4)(ii)(A) through (C) of this section.

* * * * *

(C) For control device whose model is tested under § 63.772(h), the records required in paragraph (h) of this section.

* * * * *

(7) * * *

(ix) Records identifying the carbon replacement schedule under § 63.771(d)(5) and records of each carbon replacement.

* * * * *

(g) The owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment. The owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.764(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(h) Record the following when using a control device whose model is tested under § 63.772(h) to comply with § 63.771(d), (e)(3)(ii) and (f)(1):

(1) All visible emission readings and flowrate measurements made during the compliance determination required by § 63.772(i); and

(2) All hourly records and other recorded periods when the pilot flame is absent.

(i) The date the semi-annual maintenance inspection required under § 63.773(b) is performed. Include a list of any modifications or repairs made to the control device during the inspection and other maintenance performed such as cleaning of the fuel nozzles.

21. Section 63.775 is amended by:

a. Revising paragraph (b)(1);

b. Revising paragraph (b)(6);

c. Removing and reserving paragraph (b)(7);

d. Revising paragraph (c)(1);

e. Revising paragraph (c)(6);

f. Revising paragraph (c)(7)(i);

g. Revising paragraph (d)(1)(i);

h. Revising paragraph (d)(1)(ii) introductory text;

i. Revising paragraph (d)(5)(ii);

j. Adding paragraph (d)(5)(iv);

k. Revising paragraph (d)(11);

l. Adding paragraphs (d)(13) and (d)(14);

m. Revising paragraphs (e)(2) introductory text, (e)(2)(ii)(B) and (C);

n. Adding paragraphs (e)(2)(ii)(E) and (F);

o. Adding paragraphs (e)(2)(xi) through (xiii); and

p. Adding paragraph (g) to read as follows:

§ 63.775 Reporting requirements.

* * * * *

(b) * * *

(1) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted as provided in paragraphs (b)(1)(i) and (ii) of this section.

(i) Except as otherwise provided in paragraph (ii), the initial notifications shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000 and plan to be area sources by June 17, 2002 shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

(ii) An affected source identified under § 63.760(f)(7) or (9) shall submit an initial notification required for existing affected sources under § 63.9(b)(2) within 1 year after the affected source becomes subject to the provisions of this subpart or by one year after publication of the final rule in the **Federal Register**, whichever is later. An affected source identified under § 63.760(f)(7) or (9) that plans to be an area source by three years after publication of the final rule in the **Federal Register**, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.764(j), including actions taken to correct a malfunction.

(7) [Reserved]

* * * * *

(c) * * *

(1) The initial notifications required under § 63.9(b)(2) not later than January 3, 2008. In addition to submitting your initial notification to the addressees specified under § 63.9(a), you must also submit a copy of the initial notification to the EPA's Office of Air Quality Planning and Standards. Send your notification via e-mail to *Oil and Gas Sector@epa.gov* or via U.S. mail or other mail delivery service to U.S. EPA, Sector Policies and Programs Division/ Fuels and Incineration Group (E143–01), Attn: Oil and Gas Project Leader, Research Triangle Park, NC 27711.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and

a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.764(j), including actions taken to correct a malfunction.

(7) * * *

(i) Documentation of the source's location relative to the nearest UA plus offset and UC boundaries. This information shall include the latitude and longitude of the affected source; whether the source is located in an urban cluster with 10,000 people or more; the distance in miles to the nearest urbanized area boundary if the source is not located in an urban cluster with 10,000 people or more; and the name of the nearest urban cluster with 10,000 people or more and nearest urbanized area.

* * * * *

(d) * * *

(1) * * *

(i) The condenser design analysis documentation specified in § 63.772(e)(4) of this subpart, if the owner or operator elects to prepare a design analysis.

(ii) If the owner or operator is required to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.772(e)(3) and that the test conditions are representative of current operating conditions. If the owner or operator operates a combustion control device model tested under § 63.772(h), an electronic copy of the performance test results shall be submitted via e-mail to *Oil and Gas PT@EPA.GOV.*

* * * * *

(5) * * *

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.773(d)(5). This explanation shall include any data and calculations used to develop the value and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1).

* * * * *

(iv) For each carbon adsorber, the predetermined carbon replacement schedule as required in § 63.771(d)(5)(i).

* * * * *

(11) The owner or operator shall submit the analysis prepared under § 63.771(e)(2) to demonstrate the conditions by which the facility will be operated to achieve the HAP emission reduction of 95.0 percent, or the BTEX limit in § 63.765(b)(1)(iii), through process modifications or a combination of process modifications and one or more control devices.

* * * * *

(13) If the owner or operator installs a combustion control device model tested under the procedures in § 63.772(h), the data listed under § 63.772(h)(8).

(14) For each combustion control device model tested under § 63.772(h), the information listed in paragraphs (d)(14)(i) through (vi) of this section.

(i) Name, address and telephone number of the control device manufacturer.

(ii) Control device model number.

(iii) Control device serial number.

(iv) Date of control device certification test.

(v) Manufacturer's HAP destruction efficiency rating.

(vi) Control device operating parameters, maximum allowable inlet gas flowrate.

(e) * * *

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (xiii) of this section, as applicable.

* * * * *

(ii) * * *

(B) For each excursion caused when the 365-day average condenser control efficiency is less than the value specified in § 63.773(d)(6)(ii), the report must include the 365-day average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

(C) For each excursion caused when condenser control efficiency is less than the value specified in § 63.773(d)(6)(iii), the report must include the average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

* * * * *

(E) For each excursion caused when the maximum inlet gas flow rate identified under § 63.772(h) is exceeded, the report must include the values of the inlet gas identified and the date and duration of the period that the excursion occurred.

(F) For each excursion caused when visible emissions determined under § 63.772(i) exceed the maximum allowable duration, the report must include the date and duration of the period that the excursion occurred.

* * * * *

(xi) The results of any periodic test as required in § 63.772(e)(3) conducted during the reporting period.

(xii) For each carbon adsorber used to meet the control device requirements of § 63.771(d)(1), records of each carbon replacement that occurred during the reporting period.

(xiii) For combustion control device inspections conducted in accordance with § 63.773(b) the records specified in § 63.774(i).

* * * * *

(g) *Electronic reporting.* (1) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to the EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*). Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into the EPA's WebFIRE database.

(2) All reports required by this subpart not subject to the requirements in paragraphs (g)(1) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (g)(1) of this section in paper format.

22. Appendix to subpart HH of part 63 is amended by revising Table 2 to read as follows:

Appendix to Subpart HH of Part 63—Tables

* * * * *

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH

General provisions reference	Applicable to subpart HH	Explanation
§ 63.1(a)(1)	Yes.	
§ 63.1(a)(2)	Yes.	
§ 63.1(a)(3)	Yes.	
§ 63.1(a)(4)	Yes.	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6)	Yes.	
§ 63.1(a)(7) through (a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes.	
§ 63.1(a)(11)	Yes.	
§ 63.1(a)(12)	Yes.	
§ 63.1(b)(1)	No	Subpart HH specifies applicability.
§ 63.1(b)(2)	No	Section reserved.
§ 63.1(b)(3)	Yes.	
§ 63.1(c)(1)	No	Subpart HH specifies applicability.
§ 63.1(c)(2)	Yes	Subpart HH exempts area sources from the requirement to obtain a Title V permit unless otherwise required by law as specified in § 63.760(h).
§ 63.1(c)(3) and (c)(4)	No	Section reserved.
§ 63.1(c)(5)	Yes.	
§ 63.1(d)	No	Section reserved.
§ 63.1(e)	Yes.	
§ 63.2	Yes	Except definition of major source is unique for this source category and there are additional definitions in subpart HH.
§ 63.3(a) through (c)	Yes.	
§ 63.4(a)(1) through (a)(2)	Yes.	
§ 63.4(a)(3) through (a)(5)	No	Section reserved.
§ 63.4(b)	Yes.	
§ 63.4(c)	Yes.	
§ 63.5(a)(1)	Yes.	
§ 63.5(a)(2)	Yes.	
§ 63.5(b)(1)	Yes.	
§ 63.5(b)(2)	No	Section reserved.
§ 63.5(b)(3)	Yes.	
§ 63.5(b)(4)	Yes.	
§ 63.5(b)(5)	No	Section reserved.
§ 63.5(b)(6)	Yes.	
§ 63.5(c)	No	Section reserved.
§ 63.5(d)(1)	Yes.	
§ 63.5(d)(2)	Yes.	
§ 63.5(d)(3)	Yes.	
§ 63.5(d)(4)	Yes.	
§ 63.5(e)	Yes.	
§ 63.5(f)(1)	Yes.	
§ 63.5(f)(2)	Yes.	
§ 63.6(a)	Yes.	
§ 63.6(b)(1)	Yes.	
§ 63.6(b)(2)	Yes.	
§ 63.6(b)(3)	Yes.	
§ 63.6(b)(4)	Yes.	
§ 63.6(b)(5)	Yes.	
§ 63.6(b)(6)	No	Section reserved.
§ 63.6(b)(7)	Yes.	
§ 63.6(c)(1)	Yes.	
§ 63.6(c)(2)	Yes.	
§ 63.6(c)(3) through (c)(4)	No	Section reserved.
§ 63.6(c)(5)	Yes.	
§ 63.6(d)	No	Section reserved.
§ 63.6(e)	Yes.	
§ 63.6(e)(1)(i)	No	See § 63.764(j) for general duty requirement.
§ 63.6(e)(1)(ii)	No.	
§ 63.6(e)(1)(iii)	Yes.	
§ 63.6(e)(2)	No	Section reserved.
§ 63.6(e)(3)	No.	
§ 63.6(f)(1)	No.	
§ 63.6(f)(2)	Yes.	
§ 63.6(f)(3)	Yes.	
§ 63.6(g)	Yes.	
§ 63.6(h)	No	Subpart HH does not contain opacity or visible emission standards.
§ 63.6(i)(1) through (i)(14)	Yes.	
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes.	
§ 63.6(j)	Yes.	

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.7(a)(1)	Yes.	
§ 63.7(a)(2)	Yes	But the performance test results must be submitted within 180 days after the compliance date.
§ 63.7(a)(3)	Yes.	
§ 63.7(b)	Yes.	
§ 63.7(c)	Yes.	
§ 63.7(d)	Yes.	
§ 63.7(e)(1)	No.	
§ 63.7(e)(2)	Yes.	
§ 63.7(e)(3)	Yes.	
§ 63.7(e)(4)	Yes.	
§ 63.7(f)	Yes.	
§ 63.7(g)	Yes.	
§ 63.7(h)	Yes.	
§ 63.8(a)(1)	Yes.	
§ 63.8(a)(2)	Yes.	
§ 63.8(a)(3)	No	Section reserved.
§ 63.8(a)(4)	Yes.	
§ 63.8(b)(1)	Yes.	
§ 63.8(b)(2)	Yes.	
§ 63.8(b)(3)	Yes.	
§ 63.8(c)(1)	No.	
§ 63.8(c)(1)(i)	No.	
§ 63.8(c)(1)(ii)	Yes.	
§ 63.8(c)(1)(iii)	Pending.	
§ 63.8(c)(2)	Yes.	
§ 63.8(c)(3)	Yes.	
§ 63.8(c)(4)	Yes.	
§ 63.8(c)(4)(i)	No	Subpart HH does not require continuous opacity monitors.
§ 63.8(c)(4)(ii)	Yes.	
§ 63.8(c)(5) through (c)(8)	Yes.	
§ 63.8(d)	Yes.	
§ 63.8(d)(3)	Yes	Except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.8(e)	Yes	Subpart HH does not specifically require continuous emissions monitor performance evaluation, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes.	
§ 63.8(f)(6)	Yes.	
§ 63.8(g)	No	Subpart HH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes.	
§ 63.9(b)(1)	Yes.	
§ 63.9(b)(2)	Yes	Existing sources are given 1 year (rather than 120 days) to submit this notification. Major and area sources that meet § 63.764(e) do not have to submit initial notifications.
§ 63.9(b)(3)	No	Section reserved.
§ 63.9(b)(4)	Yes.	
§ 63.9(b)(5)	Yes.	
§ 63.9(c)	Yes.	
§ 63.9(d)	Yes.	
§ 63.9(e)	Yes.	
§ 63.9(f)	No	Subpart HH does not have opacity or visible emission standards.
§ 63.9(g)(1)	Yes.	
§ 63.9(g)(2)	No	Subpart HH does not have opacity or visible emission standards.
§ 63.9(g)(3)	Yes.	
§ 63.9(h)(1) through (h)(3)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit notifications of compliance status.
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) through (h)(6)	Yes.	
§ 63.9(i)	Yes.	
§ 63.9(j)	Yes.	
§ 63.10(a)	Yes.	
§ 63.10(b)(1)	Yes	§ 63.774(b)(1) requires sources to maintain the most recent 12 months of data onsite and allows offsite storage for the remaining 4 years of data.
§ 63.10(b)(2)	Yes.	
§ 63.10(b)(2)(i)	No	
§ 63.10(b)(2)(ii)	No	See § 63.774(g) for recordkeeping of occurrence, duration, and actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Yes.	
§ 63.10(b)(2)(iv) through (b)(2)(v)	No.	
§ 63.10(b)(2)(vi) through (b)(2)(xiv)	Yes.	

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.10(b)(3)	Yes	§ 63.774(b)(1) requires sources to maintain the most recent 12 months of data on-site and allows offsite storage for the remaining 4 years of data.
§ 63.10(c)(1)	Yes.	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) through (8)(c)(8)	Yes.	
§ 63.10(c)(9)	No	Section reserved.
§ 63.10(c)(10) through (11)	No	See § 63.774(g) for recordkeeping of malfunctions.
§ 63.10(c)(12) through (14)	Yes.	
§ 63.10(c)(15)	No.	
§ 63.10(d)(1)	Yes.	
§ 63.10(d)(2)	Yes	Area sources located outside UA plus offset and UC boundaries do not have to submit performance test reports.
§ 63.10(d)(3)	Yes.	
§ 63.10(d)(4)	Yes.	
§ 63.10(d)(5)	No	See § 63.775(b)(6) or (c)(6) for reporting of malfunctions.
§ 63.10(e)(1)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(2)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(3)(i)	Yes	Subpart HH requires major sources to submit Periodic Reports semi-annually. Area sources are required to submit Periodic Reports annually. Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(3)(i)(A)	Yes.	
§ 63.10(e)(3)(i)(B)	Yes.	
§ 63.10(e)(3)(i)(C)	No	Section reserved.
§ 63.10(e)(3)(ii) through (viii)	Yes.	
§ 63.10(f)	Yes.	
§ 63.11(a) and (b)	Yes.	
§ 63.11(c), (d), and (e)	Yes.	
§ 63.12(a) through (c)	Yes.	
§ 63.13(a) through (c)	Yes.	
§ 63.14(a) and (b)	Yes.	
§ 63.15(a) and (b)	Yes.	
§ 63.16	Yes.	

Subpart HHH—[Amended]

23. Section 63.1270 is amended by:

a. Revising paragraph (a) introductory text;

b. Revising paragraph (a)(4);

c. Revising paragraphs (d)(1) and (d)(2); and

d. Adding paragraphs (d)(3), (4) and (5) to read as follows:

§ 63.1270 Applicability and designation of affected source.

(a) This subpart applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of hazardous air pollutants (HAP) emissions as defined in § 63.1271. Emissions for major source determination purposes can be estimated using the maximum natural gas throughput calculated in either paragraph (a)(1) or (2) of this section and paragraphs (a)(3) and (4) of this section. As an alternative to calculating the maximum natural gas throughput, the owner or operator of a new or existing source may use the facility design maximum natural gas throughput to estimate the maximum potential emissions. Other means to determine the facility's major source status are allowed, provided the information is documented and recorded to the Administrator's satisfaction in accordance with § 63.10(b)(3). A compressor station that transports natural gas prior to the point of custody transfer or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage source category. A facility that is determined to be an area source, but subsequently increases its emissions or its potential to emit above the major source levels (without obtaining and complying with other limitations that keep its potential to emit HAP below major source levels), and becomes a major source, must comply thereafter with all applicable provisions of this subpart starting on the applicable compliance date specified in paragraph (d) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

* * * * *

(4) The owner or operator shall determine the maximum values for other parameters used to calculate potential emissions as the maximum over the same period for which maximum throughput is determined as specified in paragraph (a)(1) or (a)(2) of this section. These parameters shall be based on an annual average or the highest single measured value. For estimating maximum potential emissions from glycol dehydration units, the glycol circulation rate used in the calculation shall be the unit's maximum rate under its physical and operational design consistent with the definition of potential to emit in § 63.2.

* * * * *

(d) * * *

(1) Except as specified in paragraphs (d)(3) through (5) of this section, the owner or operator of an affected source, the construction or reconstruction of which commenced before February 6,

1998, shall achieve compliance with the provisions of this subpart no later than June 17, 2002 except as provided for in § 63.6(i). The owner or operator of an area source, the construction or reconstruction of which commenced before February 6, 1998, that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply with this subpart 3 years after becoming a major source.

(2) Except as specified in paragraphs (d)(3) through (5) of this section, the owner or operator of an affected source, the construction or reconstruction of which commences on or after February 6, 1998, shall achieve compliance with the provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later. Area sources, the construction or reconstruction of which commences on or after February 6, 1998, that become major sources shall comply with the provisions of this standard immediately upon becoming a major source.

(3) Each affected small glycol dehydration unit, as defined in § 63.1271, located at a major source, that commenced construction before August 23, 2011 must achieve compliance no later than 3 years after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

(4) Each affected small glycol dehydration unit, as defined in § 63.1271, located at a major source, that commenced construction on or after August 23, 2011 must achieve compliance immediately upon initial startup or the date of publication of the final rule in the **Federal Register**, whichever is later.

(5) Each large glycol dehydration unit, as defined in § 63.1271, that has complied with the provisions of this subpart prior to August 23, 2011 by reducing its benzene emissions to less than 0.9 megagrams per year must achieve compliance no later than 90 days after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

* * * * *

24. Section 63.1271 is amended by:

a. Adding, in alphabetical order, new definitions for the terms ''affirmative defense,'' ''BTEX,'' ''flare,'' ''large glycol dehydration units,'' ''small glycol dehydration units''; and

b. Revising the definitions for ''glycol dehydration unit baseline operations'' and ''temperature monitoring device'' to read as follows:

§ 63.1271 Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

BTEX means benzene, toluene, ethyl benzene and xylene.

* * * * *

Flare means a thermal oxidation system using an open flame (*i.e.,* without enclosure).

* * * * *

Glycol dehydration unit baseline operations means operations representative of the large glycol dehydration unit operations as of June 17, 1999 and the small glycol dehydration unit operations as of August 23, 2011. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, glycol dehydration unit baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (*i.e.,* at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

* * * * *

Large glycol dehydration unit means a glycol dehydration unit with an actual annual average natural gas flowrate equal to or greater than 283.0 thousand standard cubic meters per day and actual annual average benzene emissions equal to or greater than 0.90 Mg/yr, determined according to § 63.1282(a).

* * * * *

Small glycol dehydration unit means a glycol dehydration unit, located at a major source, with an actual annual average natural gas flowrate less than 283.0 thousand standard cubic meters per day or actual annual average benzene emissions less than 0.90 Mg/yr, determined according to § 63.1282(a).

Temperature monitoring device means an instrument used to monitor temperature and having a minimum accuracy of ± 1 percent of the temperature being monitored expressed in °C, or ± 2.5 °C, whichever is greater. The temperature monitoring device may measure temperature in degrees Fahrenheit or degrees Celsius, or both.

* * * * *

25. Section 63.1272 is revised to read as follows:

§ 63.1272 Startups and shutdowns.

(a) The provisions set forth in this subpart shall apply at all times.

(b) The owner or operator shall not shut down items of equipment that are required or utilized for compliance with the provisions of this subpart during times when emissions are being routed to such items of equipment, if the shutdown would contravene requirements of this subpart applicable to such items of equipment. This paragraph does not apply if the owner or operator must shut down the equipment to avoid damage due to a contemporaneous startup or shutdown of the affected source or a portion thereof.

(c) During startups and shutdowns, the owner or operator shall implement measures to prevent or minimize excess emissions to the maximum extent practical.

(d) In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined in § 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, the owner or operator must timely meet the notification requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in this subpart to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

26. Section 63.1274 is amended by:

a. Revising paragraph (c) introductory text;

b. Removing and reserving paragraph (d);

c. Revising paragraph (g); and

d. Adding paragraph (h) to read as follows:

§ 63.1274 General standards.

* * * * *

(c) The owner or operator of an affected source (*i.e.,* glycol dehydration unit) located at an existing or new major source of HAP emissions shall comply with the requirements in this subpart as follows:

* * * * *

(d) [Reserved]

* * * * *

(g) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this standard to fail to take action to repair the leak(s) within the specified time. If action is taken to repair the leak(s) within the specified time, failure of that action to successfully repair the leak(s) is not a violation of this standard. However, if the repairs are unsuccessful, and a leak is detected, the owner or operator shall take further action as required by the applicable provisions of this subpart.

(h) At all times the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

27. Section 63.1275 is amended by:

a. Revising paragraph (a);

b. Revising paragraph (b)(1);

c. Revising paragraph (c)(2); and

d. Revising paragraph (c)(3) to read as follows:

§ 63.1275 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit subject to this subpart that must be controlled for air emissions as specified in paragraph (c)(1) of § 63.1274.

(b) * * *

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i) or (b)(1)(iii) of this section.

(i) The owner or operator of a large glycol dehydration unit, as defined in § 63.1271, shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(d).

(ii) [Reserved]

(iii) You must limit BTEX emissions from each small glycol dehydration unit, as defined in § 63.1271, to the limit determined in Equation 1 of this section. The limit must be met in accordance with one of the alternatives specified in paragraphs (b)(i)(iii)(A) through (D) of this section.

$$EL_{BTEX} = 6.42x10^{-5} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams} \quad \text{Equation 1}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

6.42×10^{-5} = BTEX emission limit, grams BTEX/standard cubic meter -ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day

$C_{i,BTEX}$ = BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

(A) Connect the process vent to a control device or combination of control devices through a closed-vent system. The closed vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(f).

(B) Meet the emissions limit through process modifications in accordance with the requirements specified in § 63.1281(e).

(C) Meet the emission limit for each small glycol dehydration unit using a combination of process modifications and one or more control devices through the requirements specified in paragraphs (b)(1)(iii)(A) and (B) of this section.

(D) Demonstrate that the emissions limit is met through actual uncontrolled operation of the small glycol dehydration unit. Document operational parameters in accordance with the requirements specified in § 63.1281(e) and emissions in accordance with the requirements specified in § 63.1282(a)(3).

* * * * *

(c) * * *

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the large glycol dehydration unit process vent are reduced by 95.0 percent through process modifications or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.1281(e).

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraph (c)(3)(i) or (iii) through the installation and operation of controls as specified in paragraph (b)(1) of this section.

(i) For any large glycol dehydration unit, HAP emissions are reduced by 95.0 percent or more.

(ii) [Reserved]

(iii) For each small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated in paragraph (b)(1)(iii) of this section.

28. Section 63.1281 is amended by:

a. Revising paragraph (c)(1);

b. Revising the heading of paragraph (d).

c. Adding paragraph (d) introductory text;

d. Revising paragraph (d)(1)(i) introductory text;

e. Revising paragraph (d)(1)(i)(C);

f. Revising paragraphs (d)(1)(ii) and (iii);

g. Revising paragraph (d)(4)(i);

h. Revising paragraph (d)(5)(i);

i. Revising paragraph (e)(2);

j. Revising paragraph (e)(3) introductory text;

k. Revising paragraph (e)(3)(ii); and

l. Adding paragraph (f) to read as follows:

§ 63.1281 Control equipment requirements.

* * * * *

(c) * * *

(1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in an emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

* * * * *

(d) *Control device requirements for sources except small glycol dehydration units.* Owners and operators of small glycol dehydration units shall comply with the control requirements in paragraph (f) of this section.

(1) * * *

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated in accordance with one of the following performance requirements:

* * * * *

(C) For a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 63.1282(d), operates at a minimum temperature of 760 °C.

* * * * *

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.1282(d).

(iii) A flare, as defined in § 63.1271, that is designed and operated in accordance with the requirements of § 63.11(b).

* * * * *

(4) * * *

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the emissions unit or units through the closed vent system to the control device as required under § 63.1275. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

* * * * *

(5) * * *

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon adsorption system. Records identifying the schedule for replacement and records of each carbon replacement shall be maintained as required in § 63.1284(b)(7)(ix). The schedule for replacement shall be submitted with the Notification of Compliance Status Report as specified in § 63.1285(d)(4)(iv). Each carbon replacement must be reported in the Periodic Reports as specified in § 63.1285(e)(2)(xi).

* * * * *

(e) * * *

(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, or BTEX limit determined in § 63.1275(b)(1)(iii), as applicable, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the emission reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent or, if applicable, the BTEX limit determined in § 63.1275(b)(1)(iii) for the small glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including but not limited to changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall emission reduction due to process modifications.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit

determined in § 63.1275(b)(1)(iii), as applicable, using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.1275(b)(1)(iii), as applicable, using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (e)(3)(ii) of this section.

* * * * *

(ii) The owner or operator shall comply with the control device requirements specified in paragraph (d) or (f) of this section, as applicable, except that the emission reduction or limit achieved shall be the emission reduction or limit specified for the control device(s) in paragraph (e)(2) of this section.

(f) *Control device requirements for small glycol dehydration units.* (1) The control device used to meet BTEX the emission limit calculated in § 63.1275(b)(1)(iii) shall be one of the control devices specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.1282(d). If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.1282(d); or

(iii) A flare, as defined in § 63.1271, that is designed and operated in accordance with the requirements of § 63.11(b).

(2) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.1283(d), the owner or operator shall demonstrate compliance according to the requirements of either § 63.1282(e) or (h).

(3) For each carbon adsorption system used as a control device to meet the requirements of paragraph (f)(1) of this section, the owner or operator shall manage the carbon as required under (d)(5)(i) and (ii) of this section.

29. Section 63.1282 is amended by:

a. Revising paragraph (a) introductory text;

b. Revising paragraph (a)(1)(ii);

c. Revising paragraph (a)(2);

d. Adding paragraph (c);

e. Revising paragraph (d) introductory text;

f. Revising paragraphs (d)(1)(i) through (v);

g. Revising paragraph (d)(2);

h. Revising paragraph (d)(3) introductory text;

i. Revising paragraph (d)(3)(i)(B);

j. Revising paragraph (d)(3)(iv)(C)(*1*);

k. Adding paragraphs (d)(3)(v) and (vi);

l. Revising paragraph (d)(4) introductory text;

m. Revising paragraph (d)(4)(i);

n. Revising paragraph (d)(5);

o. Revising paragraph (e) introductory text;

p. Revising paragraphs (e)(2) and (e)(3);

q. Adding paragraphs (e)(4) through (e)(6);

r. Revising paragraph (f) introductory text;

s. Revising paragraph (f)(1);

t. Revising paragraph (f)(2) introductory text;

u. Revising paragraph (f)(2)(iii);

v. Revising paragraph (f)(3); and

w. Adding paragraphs (g) and (h) to read as follows:

§ 63.1282 Test methods, compliance procedures, and compliance demonstrations.

(a) *Determination of glycol dehydration unit flowrate, benzene emissions, or BTEX emissions.* The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate, benzene emissions, or BTEX emissions.

(1) * * *

(ii) The owner or operator shall document, to the Administrator's satisfaction, the actual annual average natural gas flowrate to the glycol dehydration unit.

(2) The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (a)(2)(i) or (a)(2)(ii) of this section. Emissions shall be determined either uncontrolled or with federally enforceable controls in place.

(i) The owner or operator shall determine actual average benzene or BTEX emissions using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1); or

(ii) The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement by performing three runs of Method 18 in 40 CFR part 60, appendix A (or an equivalent method), and averaging the results of the three runs. Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

* * * * *

(c) *Test procedures and compliance demonstrations for small glycol dehydration units.* This paragraph applies to the test procedures for small dehydration units.

(1) If the owner or operator is using a control device to comply with the emission limit in § 63.1275(b)(1)(iii), the requirements of paragraph (d) of this section apply. Compliance is demonstrated using the methods specified in paragraph (e) of this section.

(2) If no control device is used to comply with the emission limit in § 63.1275(b)(1)(iii), the owner or operator must determine the glycol dehydration unit BTEX emissions as specified in paragraphs (c)(2)(i) through (iii) of this section. Compliance is demonstrated if the BTEX emissions determined as specified in paragraphs (c)(2)(i) through (iii) are less than the emission limit calculated using the equation in § 63.1275(b)(1)(iii).

(i) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites at the outlet of the glycol dehydration unit process vent. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(ii) The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(iii) The BTEX emissions from the outlet of the glycol dehydration unit process vent shall be determined using the procedures specified in paragraph (d)(3)(v) of this section. As an alternative, the mass rate of BTEX at the outlet of the glycol dehydration unit process vent may be calculated using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and shall be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1). When the BTEX mass rate is calculated for glycol dehydration units using the model GRI–GLYCalc™, all BTEX measured by Method 18, 40 CFR part 60, appendix A, shall be summed.

(d) *Control device performance test procedures.* This paragraph applies to the performance testing of control devices. The owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) using a performance test as specified in paragraph (d)(3) of this section. Owners or operators using a condenser have the option to use a design analysis as specified in paragraph (d)(4) of this section. The owner or operator may elect to use the alternative procedures in paragraph (d)(5) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent. As an alternative to conducting a performance test under this section for combustion control devices, a control device that can be demonstrated to meet the performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) through a performance test conducted by the manufacturer, as specified in paragraph (g) of this section, can be used.

(1) * * *

(i) Except as specified in paragraph (d)(2) of this section, a flare, as defined in § 63.1271, that is designed and operated in accordance with § 63.11(b);

(ii) Except for control devices used for small glycol dehydration units, a boiler or process heater with a design heat input capacity of 44 megawatts or greater;

(iii) Except for control devices used for small glycol dehydration units, a boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel;

(iv) Except for control devices used for small glycol dehydration units, a boiler or process heater burning hazardous waste for which the owner or operator has either been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H, or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(v) Except for control devices used for small glycol dehydration units, a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O, or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

* * * * *

(2) An owner or operator shall design and operate each flare, as defined in § 63.1271, in accordance with the requirements specified in § 63.11(b) and the compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

(3) For a performance test conducted to demonstrate that a control device meets the requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) the owner or operator shall use the test methods and procedures specified in paragraphs (d)(3)(i) through (v) of this section. The initial and periodic performance tests shall be conducted according to the schedule specified in paragraph (d)(3)(vi) of this section.

(i) * * *

(B) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.1281(d)(1)(i)(B), or the BTEX emission limit specified in § 63.1275(b)(1)(iii), the sampling site shall be located at the outlet of the combustion device.

* * * * *

(iv) * * *

(C) * * *

(*1*) The emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B, 40 CFR part 60, appendix A, shall be used to determine the oxygen concentration ($\%O_{2d}$). The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

* * * * *

(v) To determine compliance with the BTEX emission limit specified in § 63.1281(f)(1) the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420–99 (2004), as specified in § 63.772(a)(1)(ii); or any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. The following procedures shall be used to calculate BTEX emissions:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The mass rate of BTEX (E_o) shall be computed using the equations and procedures specified in paragraphs (d)(3)(v)(B)(*1*) and (*2*) of this section.

(*1*) The following equation shall be used:

$$E_o = K_2 \left(\sum_{j=1}^{n} C_{oj} M_{oj} \right) Q_o$$

Where:

E_o = Mass rate of BTEX at the outlet of the control device, dry basis, kilogram per hour.

C_{oj} = Concentration of sample component j of the gas stream at the outlet of the control device, dry basis, parts per million by volume.

M_{oj} = Molecular weight of sample component j of the gas stream at the outlet of the control device, gram/gram-mole.

Q_o = Flowrate of gas stream at the outlet of the control device, dry standard cubic meter per minute.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees C.

n = Number of components in sample.

(*2*) When the BTEX mass rate is calculated, only BTEX compounds measured by Method 18, 40 CFR part 60, appendix A, or ASTM D6420–99 (2004) as specified in § 63.772(a)(1)(ii), shall be summed using the equations in paragraph (d)(3)(v)(B)(*1*) of this section.

(vi) The owner or operator shall conduct performance tests according to the schedule specified in paragraphs (d)(3)(vi)(A) and (B) of this section.

(A) An initial performance test shall be conducted within 180 days after the compliance date that is specified for each affected source in § 63.1270(d)(3) and (4) except that the initial performance test for existing combustion control devices at existing major sources shall be conducted no later than 3 years after the date of publication of the final rule in the **Federal Register**. If the owner or operator of an existing combustion control device at an existing major source chooses to replace such device with a control device whose model is tested under § 63.1282(g), then the newly installed device shall comply with all provisions of this subpart no later than 3 years after the date of publication of the final rule in the **Federal Register**. The performance test results shall be submitted in the Notification of Compliance Status Report as required in § 63.1285(d)(1)(ii).

(B) Periodic performance tests shall be conducted for all control devices required to conduct initial performance tests except as specified in paragraphs (e)(3)(vi)(B)(*1*) and (*2*) of this section. The first periodic performance test shall be conducted no later than 60 months after the initial performance test required in paragraph (d)(3)(vi)(A) of this section. Subsequent periodic performance tests shall be conducted at intervals no longer than 60 months following the previous periodic performance test or whenever a source desires to establish a new operating limit. The periodic performance test results must be submitted in the next Periodic Report as specified in § 63.1285(e)(2)(x). Combustion control devices meeting the criteria in either paragraph (e)(3)(vi)(B)(*1*) or (*2*) of this section are not required to conduct periodic performance tests.

(*1*) A control device whose model is tested under, and meets the criteria of, § 63.1282(g), or

(*2*) A combustion control device tested under § 63.1282(d) that meets the outlet TOC or HAP performance level specified in § 63.1281(d)(1)(i)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC or HAP performance level.

* * * * *

(4) For a condenser design analysis conducted to meet the requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1), the owner or operator shall meet the requirements specified in paragraphs (d)(4)(i) and (d)(4)(ii) of this section. Documentation of the design analysis shall be submitted as a part of the Notification of Compliance Status Report as required in § 63.1285(d)(1)(i).

(i) The condenser design analysis shall include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet. As an alternative to the condenser design analysis, an owner or operator may elect to use the procedures specified in paragraph (d)(5) of this section.

* * * * *

(5) As an alternative to the procedures in paragraph (d)(4)(i) of this section, an owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions,'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(e) *Compliance demonstration for control devices performance requirements.* This paragraph applies to the demonstration of compliance with the control device performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), and (f)(1). Compliance shall be demonstrated using the requirements in paragraphs (e)(1) through (3) of this section. As an alternative, an owner or operator that installs a condenser as the control device to achieve the requirements specified in § 63.1281(d)(1)(ii), (e)(3)(ii), or (f)(1) may demonstrate compliance according to paragraph (f) of this section. An owner or operator may switch between compliance with paragraph (e) of this section and compliance with paragraph (f) of this section only after at least 1 year of operation in compliance with the selected approach. Notification of such a change in the compliance method shall be reported in the next Periodic Report, as required in § 63.1285(e), following the change.

* * * * *

(2) The owner or operator shall calculate the daily average of the applicable monitored parameter in accordance with § 63.1283(d)(4) except that the inlet gas flowrate to the control device shall not be averaged.

(3) Compliance is achieved when the daily average of the monitoring parameter value calculated under paragraph (e)(2) of this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under paragraph (e)(1) of this section. For inlet gas flowrate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under § 63.1282(g).

(4) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), the CMS required in § 63.1283(d) must be operated at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Monitoring system repairs are required to be completed in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(5) Data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. All the data collected during all other required data collection periods must be used in assessing the operation of the control device and associated control system.

(6) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

(f) *Compliance demonstration with percent reduction or emission limit performance requirements—condensers.* This paragraph applies to the demonstration of compliance with the performance requirements specified in § 63.1281(d)(1)(ii), (e)(3) or (f)(1) for condensers. Compliance shall be demonstrated using the procedures in paragraphs (f)(1) through (f)(3) of this section.

(1) The owner or operator shall establish a site-specific condenser performance curve according to the procedures specified in § 63.1283(d)(5)(ii). For sources required to meet the BTEX limit in accordance with § 63.1281(e) or (f)(1) the owner or operator shall identify the minimum percent reduction necessary to meet the BTEX limit.

(2) Compliance with the percent reduction requirement in § 63.1281(d)(1)(ii), (e)(3), or (f)(1) shall be demonstrated by the procedures in paragraphs (f)(2)(i) through (iii) of this section.

* * * * *

(iii) Except as provided in paragraphs (f)(2)(iii)(A), (B), and (D) of this section, at the end of each operating day the owner or operator shall calculate the 30-day average HAP, or BTEX, emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (f)(2)(ii) of this section for the preceding 30 operating days. If the owner or operator uses a combination of process modifications and a condenser in accordance with the requirements of § 63.1281(e), the 30-day average HAP emission, or BTEX, emission reduction, shall be calculated using the emission reduction achieved through process modifications and the condenser efficiency as determined in paragraph (f)(2)(ii) of this section, both for the preceding 30 operating days.

(A) After the compliance date specified in § 63.1270(d), an owner or operator of a facility that stores natural gas that has less than 30 days of data for determining the average HAP, or BTEX, emission reduction, as appropriate, shall calculate the cumulative average at the end of the withdrawal season, each season, until 30 days of condenser operating data are accumulated. For a facility that does not store natural gas, the owner or operator that has less than 30 days of data for determining average HAP, or BTEX, emission reduction, as appropriate, shall calculate the cumulative average at the end of the calendar year, each year, until 30 days of condenser operating data are accumulated.

(B) After the compliance date specified in § 63.1270(d), for an owner or operator that has less than 30 days of data for determining the average HAP, or BTEX, emission reduction, as appropriate, compliance is achieved if the average HAP, or BTEX, emission reduction, as appropriate, calculated in paragraph (f)(2)(iii)(A) of this section is equal to or greater than 95.0 percent.

* * * * *

(3) Compliance is achieved based on the applicable criteria in paragraphs (f)(3)(i) or (ii) of this section.

(i) For sources meeting the HAP emission reduction specified in § 63.1281(d)(1)(ii) or (e)(3) if the average HAP emission reduction calculated in paragraph (f)(2)(iii) of this section is equal to or greater than 95.0 percent.

(ii) For sources required to meet the BTEX limit under § 63.1281(e)(3) or (f)(1), compliance is achieved if the average BTEX emission reduction calculated in paragraph (f)(2)(iii) of this section is equal to or greater than the minimum percent reduction identified in paragraph (f)(1) of this section.

* * * * *

(g) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer shall demonstrate that a specific model of control device achieves the performance requirements in (g)(7) of this section by conducting a performance test as specified in paragraphs (g)(2) through (6) of this section.

(2) Performance testing shall consist of three one-hour (or longer) test runs for each of the four following firing rate settings making a total of 12 test runs per test. Propene (propylene) gas shall be used for the testing fuel. All fuel analyses shall be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at 0 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 100 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 0 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures shall be tested simultaneously and with all burners operational. Results shall be reported for the each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data shall be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. Data shall be submitted with the test report in accordance with paragraph (g)(8)(iii) of this section.

(4) Inlet testing shall be conducted as specified in paragraphs (g)(4)(i) through (iii) of this section.

(i) The fuel flow metering system shall be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure fuel flow rate at the control device inlet location. The fitting for filling fuel sample containers shall be located a minimum of 8 pipe diameters upstream of any inlet fuel flow monitoring meter.

(ii) Inlet flow rate shall be determined using Method 2A, 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) Inlet fuel sampling shall be conducted in accordance with the criteria in paragraphs (g)(4)(iii)(A) and (B) of this section.

(A) At the inlet fuel sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 1 hour period. Filling shall be conducted as specified in the following:

(*1*) Open the canister sampling valve at the beginning of the total hydrocarbon (THC) test, and close the canister at the end of the THC test.

(*2*) Fill one canister for each THC test run.

(*3*) Label the canisters individually and record on a chain of custody form.

(B) Each fuel sample shall be analyzed using the following methods. The results shall be included in the test report.

(*1*) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03.

(*2*) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03.

(*3*) Carbonyl sulfide, carbon disulfide plus mercaptans using ASTM D5504.

(*4*) Higher heating value using ASTM D3588–98 or ASTM D4891–89.

(5) Outlet testing shall be conducted in accordance with the criteria in paragraphs (g)(5)(i) through (v) of this section.

(i) Sampling and flowrate measured in accordance with the following:

(A) The outlet sampling location shall be a minimum of 4 equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports shall be used.

(B) Flow rate shall be measured using Method 1, 40 CFR part 60, Appendix 1, for determining flow measurement traverse point location; and Method 2, 40 CFR part 60, Appendix 1, shall be used to measure duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer shall be used to obtain an accurate flow profile.

(ii) Molecular weight shall be determined as specified in paragraphs (g)(4)(iii)(B), and (g)(5)(ii)(A) and (B) of this section.

(A) An integrated bag sample shall be collected during the Method 4, 40 CFR part 60, Appendix A, moisture test. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the following criteria:

(*1*) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(*2*) The sampling line shall be purged with stack gas before opening the valve and beginning to fill the bag.

(*3*) The bag contents shall be kneaded or otherwise vigorously mixed prior to the GC analysis.

(*4*) The GC–TCD calibration procedure in Method 3C, 40 CFR part 60, Appendix A, shall be modified by using EPAAlt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, the initial calibration using at least three concentration levels shall be repeated.

(B) Report the molecular weight of: O_2, CO_2, methane (CH4), and N_2 and include in the test report submitted under § 63.775(d)(iii). Moisture shall be determined using Method 4, 40 CFR part 60, Appendix A. Traverse both ports with the Method 4, 40 CFR part 60, Appendix A, sampling train during each test run. Ambient air shall not be introduced into the Method 3C, 40 CFR part 60, Appendix A, integrated bag sample during the port change.

(iv) Carbon monoxide shall be determined using Method 10, 40 CFR part 60, Appendix A. The test shall be run at the same time and with the sample points used for the EPA Method 25A, 40 CFR part 60, Appendix A, testing. An instrument range of 0–10 per million by volume-dry (ppmvd) shall be used.

(v) Visible emissions shall be determined using Method 22, 40 CFR part 60, Appendix A. The test shall be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, will be taken once per test run and the four photos included in the test report.

(6) Total hydrocarbons (THC) shall be determined as specified by the following criteria:

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, Appendix A, except the option for locating the probe in the center 10 percent of the stack shall not be allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during the testing.

(ii) A valid test shall consist of three Method 25A, 40 CFR part 60, Appendix A, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases will be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121 (or more recent if updated since 1999).

(v) THC measurements shall be reported in terms of ppmvw as propane.

(vi) THC results shall be corrected to 3 percent CO_2, as measured by Method 3C, 40 CFR part 60, Appendix A.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(7) Performance test criteria:

(i) The control device model tested must meet the criteria in paragraphs (g)(7)(i)(A) through (C) of this section:

(A) Method 22, 40 CFR part 60, Appendix A, results under paragraph (g)(5)(v) of this section with no indication of visible emissions, and

(B) Average Method 25A, 40 CFR part 60, Appendix A, results under paragraph (g)(6) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2, and

(C) Average CO emissions determined under paragraph (g)(5)(iv) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(ii) The manufacturer shall determine a maximum inlet gas flow rate which shall not be exceeded for each control device model to achieve the criteria in paragraph (g)(7)(i) of this section.

(iii) A control device meeting the criteria in paragraph (g)(7)(i)(A) through (C) of this section will have demonstrated a destruction efficiency of 98.0 percent for HAP regulated under this subpart.

(8) The owner or operator of a combustion control device model tested under this section shall submit the information listed in paragraphs (g)(8)(i) through (iii) in the test report required under § 63.775(d)(1)(iii).

(i) Full schematic of the control device and dimensions of the device components.

(ii) Design net heating value (minimum and maximum) of the device.

(iii) Test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flow rate.

(iv) Air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (g)(8)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold pressure.

(I) Pilot flame sensor.

(J) Pilot flame design fuel and fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report shall include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated with test times and calibration values.

(h) *Compliance demonstration for combustion control devices—manufacturers' performance test.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (g) of this section. Owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.1281(d)(1), (e)(3)(ii) or (f)(1), by installing a device tested under paragraph (g) of this section and complying with the following criteria:

(1) The inlet gas flow rate shall meet the range specified by the manufacturer. Flow rate shall be measured as specified in § 63.1283(d)(3)(i)(H)(*1*).

(2) A pilot flame shall be present at all times of operation. The pilot flame shall be monitored in accordance with § 63.1283(d)(3)(i)(H)(*2*).

(3) Devices shall be operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. A visible emissions test using Method 22, 40 CFR part 60, Appendix A, shall be performed monthly. The observation period shall be 2 hours and shall be used according to Method 22.

(4) Compliance with the operating parameter limit is achieved when the following criteria are met:

(i) The inlet gas flow rate monitored under paragraph (h)(1) of this section is equal to or below the maximum established by the manufacturer; and

(ii) The pilot flame is present at all times; and

(iii) During the visible emissions test performed under paragraph (h)(3) of this section the duration of visible emissions does not exceed a total of 5 minutes during the observation period. Devices failing the visible emissions test shall follow the requirements in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) Following the first failure, the fuel nozzle(s) and burner tubes shall be replaced.

(B) If, following replacement of the fuel nozzle(s) and burner tubes as specified in paragraph (h)(4)(iii)(A), the visible emissions test is not passed in the next scheduled test, either a performance test shall be performed under paragraph (d) of this section, or the device shall be replaced with another control device whose model was tested, and meets, the requirements in paragraph (g) of this section.

30. Section 63.1283 is amended by:

a. Adding paragraph (b);

b. Revising paragraph (d)(1) introductory text;

c. Revising paragraph (d)(1)(ii) and adding paragraphs (d)(1)(iii) and (iv);

d. Revising paragraph (d)(2)(i) and (d)(2)(ii);

e. Revising paragraphs (d)(3)(i)(A) and (B);

f. Revising paragraphs (d)(3)(i)(D) and (E);

g. Revising paragraphs (d)(3)(i)(F)(*1*) and (*2*);

h. Revising paragraph (d)(3)(i)(G);

i. Adding paragraph (d)(3)(i)(H);

j. Revising paragraph (d)(4);

k. Revising paragraph (d)(5)(i);

l. Revising paragraphs (d)(5)(ii)(A) through (C);

m. Revising paragraph (d)(6) introductory text;

n. Revising paragraph (d)(6)(ii);

o. Adding paragraph (d)(6)(v);

p. Revising paragraph (d)(8)(i)(A); and

q. Revising paragraph (d)(8)(ii) to read as follows:

§ 63.1283 Inspection and monitoring requirements.

* * * * *

(b) The owner or operator of a control device whose model was tested under 63.1282(g) shall develop an inspection and maintenance plan for each control device. At a minimum, the plan shall contain the control device manufacturer's recommendations for ensuring proper operation of the device. Semi-annual inspections shall be conducted for each control device with maintenance and replacement of control device components made in accordance with the plan.

* * * * *

(d) *Control device monitoring requirements.* (1) For each control device except as provided for in paragraph (d)(2) of this section, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of paragraphs (d)(3) through (9) of this section. Owners or operators that install and operate a flare in accordance with § 63.1281(d)(1)(iii) or (f)(1)(iii) are exempt from the requirements of paragraphs (d)(4) and (5) of this section. The continuous monitoring system shall be designed and operated so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 63.1281(d), (e)(3), or (f)(1). Each continuous parameter monitoring system shall meet the following specifications and requirements:

* * * * *

(ii) A site-specific monitoring plan must be prepared that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraph (d) of this section and in § 63.8(d). Each CPMS must be installed, calibrated, operated, and maintained in accordance with the procedures in your approved site-specific monitoring plan. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (d)(1)(ii)(A) through (E) of this section in your site-specific monitoring plan.

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(B) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(C) Equipment performance checks, system accuracy audits, or other audit procedures;

(D) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (c)(3); and

(E) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(iii) The owner or operator must conduct the CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(iv) The owner or operator must conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

(2) * * *

(i) Except for control devices for small glycol dehydration units, a boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel;

(ii) Except for control devices for small glycol dehydration units, a boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) * * *

(i) * * *

(A) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 63.1282(d) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

(B) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperatures at two locations and have a minimum accuracy of ± 1 percent of the temperatures being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

* * * * *

(D) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

(E) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.8 degrees C, whichever value is greater. The temperature sensor shall be installed at a location in the exhaust vent stream from the condenser.

(F) * * *

(*1*) A continuous parameter monitoring system to measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. The mechanical connections for leakage must be checked at least every month, and a visual inspection must be performed at least every 3 months of all components of the flow CPMS for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow CPMS is not equipped with a redundant flow sensor; and

(*2*) A continuous parameter monitoring system to measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and to measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater.

(G) For a nonregenerative-type carbon adsorption system, the owner or operator shall monitor the design carbon replacement interval established using a performance test performed in accordance with § 63.1282(d)(3) and shall be based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device whose model is tested under § 63.1282(g):

(*1*) A continuous monitoring system that measures gas flow rate at the inlet to the control device. The monitoring instrument shall have an accuracy of plus or minus 2 percent or better.

(*2*) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

* * * * *

(4) Using the data recorded by the monitoring system, except for inlet gas flowrate, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(5) * * *

(i) The owner or operator shall establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1). Each minimum or maximum operating parameter value shall be established as follows:

(A) If the owner or operator conducts performance tests in accordance with the requirements of § 63.1282(d)(3) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer's recommendations or a combination of both.

(B) If the owner or operator uses a condenser design analysis in accordance with the requirements of § 63.1282(d)(4) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the condenser design analysis and may be supplemented by the condenser manufacturer's recommendations.

(C) If the owner or operator operates a control device where the performance test requirement was met under § 63.1282(g) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii) or (f)(1), then the maximum inlet gas flow rate shall be established based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(ii) * * *

(A) If the owner or operator conducts a performance test in accordance with the requirements of § 63.1282(d)(3) to demonstrate that the condenser achieves the applicable performance requirements in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.1282(d)(4)(i) to demonstrate that the condenser achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on the condenser design analysis and may be supplemented by the control device manufacturer's recommendations.

(C) As an alternative to paragraph (d)(5)(ii)(B) of this section, the owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(6) An excursion for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (d)(6)(i) through (d)(6)(v) of this section being met. When multiple operating parameters are monitored for the same control device and during the same operating day, and more than one of these operating parameters meets an excursion criterion specified in paragraphs (d)(6)(i) through (d)(6)(iv) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

* * * * *

(ii) For sources meeting § 63.1281(d)(1)(ii), an excursion occurs when average condenser efficiency calculated according to the requirements specified in § 63.1282(f)(2)(iii) is less than 95.0 percent, as specified in § 63.1282(f)(3). For sources meeting § 63.1281(f)(1), an excursion occurs when the 30-day average condenser efficiency calculated according to the requirements of § 63.1282(f)(2)(iii) is less than the identified 30-day required percent reduction.

* * * * *

(v) For control device whose model is tested under § 63.1282(g) an excursion occurs when:

(A) The inlet gas flow rate exceeds the maximum established during the test conducted under § 63.1282(g).

(B) Failure of the monthly visible emissions test conducted under § 63.1282(h)(3) occurs.

(8) * * *

(i) * * *

(A) During a malfunction when the affected facility is operated during such period in accordance with § 63.6(e)(1); or

* * * * *

(ii) For each control device, or combinations of control devices, installed on the same emissions unit, one excused excursion is allowed per semiannual period for any reason. The initial semiannual period is the 6-month reporting period addressed by the first Periodic Report submitted by the owner or operator in accordance with § 63.1285(e) of this subpart.

* * * * *

31. Section 63.1284 is amended by:

a. Revising paragraph (b)(3) introductory text;

b. Removing and reserving paragraph (b)(3)(ii);

c. Revising paragraph (b)(4)(ii);

d. Adding paragraph (b)(7)(ix); and

e. Adding paragraph (f), (g) and (h) to read as follows:

§ 63.1284 Recordkeeping requirements.

* * * * *

(b) * * *

(3) Records specified in § 63.10(c) for each monitoring system operated by the owner or operator in accordance with the requirements of § 63.1283(d). Notwithstanding the previous sentence, monitoring data recorded during periods identified in paragraphs (b)(3)(i) through (iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating or failed to collect required data.

* * * * *

(ii) [Reserved]

* * * * *

(4) * * *

(ii) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.1283(d)(4) of this subpart, except as specified in paragraphs (b)(4)(ii)(A) through (C) of this section.

(A) For flares, the records required in paragraph (e) of this section.

(B) For condensers installed to comply with § 63.1275, records of the annual 30-day rolling average condenser efficiency determined under § 63.1282(f) shall be kept in addition to the daily averages.

(C) For a control device whose model is tested under § 63.1282(g), the records required in paragraph (g) of this section.

* * * * *

(7) * * *

(ix) Records identifying the carbon replacement schedule under § 63.1281(d)(5) and records of each carbon replacement.

* * * * *

(f) The owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment. The owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.1274(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(g) Record the following when using a control device whose model is tested under § 63.1282(g) to comply with § 63.1281(d), (e)(3)(ii) and (f)(1):

(1) All visible emission readings and flowrate measurements made during the compliance determination required by § 63.1282(h); and

(2) All hourly records and other recorded periods when the pilot flame is absent.

(h) The date the semi-annual maintenance inspection required under § 63.1283(b) is performed. Include a list of any modifications or repairs made to the control device during the inspection and other maintenance performed such as cleaning of the fuel nozzles.

32. Section 63.1285 is amended by:

a. Revising paragraph (b)(1);

b. Revising paragraph (b)(6);

c. Removing paragraph (b)(7);

d. Revising paragraph (d)(1) introductory text;

e. Revising paragraph (d)(1)(i);

f. Revising paragraph (d)(1)(ii) introductory text;

g. Revising paragraph (d)(2) introductory text;

h. Revising paragraph (d)(4)(ii);

i. Adding paragraph (d)(4)(iv);

j. Revising paragraph (d)(10);

k. Adding paragraphs (d)(11) and (d)(12);

l. Revising paragraph (e)(2) introductory text;

m. Revising paragraph (e)(2)(ii)(B);

n. Adding paragraphs (e)(2)(ii)(D) and (E);

o. Adding paragraphs (e)(2)(x), (xi) and (xii); and

p. Adding paragraph (g) to read as follows:

§ 63.1285 Reporting requirements.

* * * * *

(b) * * *

(1) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted as provided in paragraphs (b)(1)(i) and (ii) of this section.

(i) Except as otherwise provided in paragraph (b)(1)(ii) of this section, the initial notification shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000 and plan to be area sources by June 17, 2002 shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

(ii) An affected source identified under § 63.1270(d)(3) shall submit an initial notification required for existing affected sources under § 63.9(b)(2) within 1 year after the affected source becomes subject to the provisions of this subpart or by one year after publication of the final rule in the **Federal Register**, whichever is later. An affected source identified under § 63.1270(d)(3) that plans to be an area source by three years after publication of the final rule in the **Federal Register**, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of

actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.1274(h), including actions taken to correct a malfunction.

* * * * *

(d) * * *

(1) If a closed-vent system and a control device other than a flare are used to comply with § 63.1274, the owner or operator shall submit the information in paragraph (d)(1)(iii) of this section and the information in either paragraph (d)(1)(i) or (ii) of this section.

(i) The condenser design analysis documentation specified in § 63.1282(d)(4) of this subpart if the owner or operator elects to prepare a design analysis; or

(ii) If the owner or operator is required to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.1282(d)(3), and that the test conditions are representative of current operating conditions. If the owner or operator operates a combustion control device model tested under § 63.1282(g), an electronic copy of the performance test results shall be submitted via e-mail to *Oil_and_Gas_PT@EPA.GOV*.

* * * * *

(2) If a closed-vent system and a flare are used to comply with § 63.1274, the owner or operator shall submit performance test results including the information in paragraphs (d)(2)(i) and (ii) of this section. The owner or operator shall also submit the information in paragraph (d)(2)(iii) of this section.

* * * * *

(4) * * *

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.1283(d)(5) of this subpart. This explanation shall include any data and calculations used to develop the value, and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1).

* * * * *

(iv) For each carbon adsorber, the predetermined carbon replacement schedule as required in § 63.1281(d)(5)(i).

* * * * *

(10) The owner or operator shall submit the analysis prepared under § 63.1281(e)(2) to demonstrate that the conditions by which the facility will be operated to achieve the HAP emission reduction of 95.0 percent, or the BTEX limit in § 63.1275(b)(1)(iii) through process modifications or a combination of process modifications and one or more control devices.

(11) If the owner or operator installs a combustion control device model tested under the procedures in § 63.1282(g), the data listed under § 63.1282(g)(8).

(12) For each combustion control device model tested under § 63.1282(g), the information listed in paragraphs (d)(12)(i) through (vi) of this section.

(i) Name, address and telephone number of the control device manufacturer.

(ii) Control device model number.

(iii) Control device serial number.

(iv) Date of control device certification test.

(v) Manufacturer's HAP destruction efficiency rating.

(vi) Control device operating parameters, maximum allowable inlet gas flowrate.

* * * * *

(e) * * *

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (xii) of this section, as applicable.

* * * * *

(ii) * * *

(B) For each excursion caused when the 30-day average condenser control efficiency is less than the value, as specified in § 63.1283(d)(6)(ii), the report must include the 30-day average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

* * * * *

(D) For each excursion caused when the maximum inlet gas flow rate identified under § 63.1282(g) is exceeded, the report must include the values of the inlet gas identified and the date and duration of the period that the excursion occurred.

(E) For each excursion caused when visible emissions determined under § 63.1282(h) exceed the maximum allowable duration, the report must include the date and duration of the period that the excursion occurred.

* * * * *

(x) The results of any periodic test as required in § 63.1282(d)(3) conducted during the reporting period.

(xi) For each carbon adsorber used to meet the control device requirements of § 63.1281(d)(1), records of each carbon replacement that occurred during the reporting period.

(xii) For combustion control device inspections conducted in accordance with § 63.1283(b) the records specified in § 63.1284(h).

* * * * *

(g) *Electronic reporting.* (1) As of January 1, 2012, and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to the EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/).* Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into the EPA's WebFIRE database.

(2) All reports required by this subpart not subject to the requirements in paragraphs (g)(1) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (g)(1) of this section in paper format.

33. Section 63.1287 is amended by revising paragraph (a) to read as follows:

§ 63.1287 Alternative means of emission limitation.

(a) If, in the judgment of the Administrator, an alternative means of emission limitation will achieve a reduction in HAP emissions at least equivalent to the reduction in HAP emissions from that source achieved under the applicable requirements in §§ 63.1274 through 63.1281, the Administrator will publish a notice in the **Federal Register** permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

* * * * *

34. Appendix to Subpart HHH of Part 63—Table is amended by revising Table 2 to read as follows:

Appendix to Subpart HHH of Part 63—Tables

* * * * *

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.1(a)(1)	Yes.	
§ 63.1(a)(2)	Yes.	
§ 63.1(a)(3)	Yes.	
§ 63.1(a)(4)	Yes.	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6) through (a)(8)	Yes.	
§ 63.1(a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes.	
§ 63.1(a)(11)	Yes.	
§ 63.1(a)(12) through (a)(14)	Yes.	
§ 63.1(b)(1)	No	Subpart HHH specifies applicability.
§ 63.1(b)(2)	Yes.	
§ 63.1(b)(3)	No.	
§ 63.1(c)(1)	No	Subpart HHH specifies applicability.
§ 63.1(c)(2)	No.	
§ 63.1(c)(3)	No	Section reserved.
§ 63.1(c)(4)	Yes.	
§ 63.1(c)(5)	Yes.	
§ 63.1(d)	No	Section reserved.
§ 63.1(e)	Yes.	
§ 63.2	Yes	Except definition of major source is unique for this source category and there are additional definitions in subpart HHH.
§ 63.3(a) through (c)	Yes.	
§ 63.4(a)(1) through (a)(3)	Yes.	
§ 63.4(a)(4)	No	Section reserved.
§ 63.4(a)(5)	Yes.	
§ 63.4(b)	Yes.	
§ 63.4(c)	Yes.	
§ 63.5(a)(1)	Yes.	
§ 63.5(a)(2)	No	Preconstruction review required only for major sources that commence construction after promulgation of the standard.
§ 63.5(b)(1)	Yes.	
§ 63.5(b)(2)	No	Section reserved.
§ 63.5(b)(3)	Yes.	
§ 63.5(b)(4)	Yes.	
§ 63.5(b)(5)	Yes.	
§ 63.5(b)(6)	Yes.	
§ 63.5(c)	No	Section reserved.
§ 63.5(d)(1)	Yes.	
§ 63.5(d)(2)	Yes.	
§ 63.5(d)(3)	Yes.	
§ 63.5(d)(4)	Yes.	
§ 63.5(e)	Yes.	
§ 63.5(f)(1)	Yes.	
§ 63.5(f)(2)	Yes.	
§ 63.6(a)	Yes.	
§ 63.6(b)(1)	Yes.	
§ 63.6(b)(2)	Yes.	
§ 63.6(b)(3)	Yes.	
§ 63.6(b)(4)	Yes.	
§ 63.6(b)(5)	Yes.	
§ 63.6(b)(6)	No	Section reserved.
§ 63.6(b)(7)	Yes.	
§ 63.6(c)(1)	Yes.	
§ 63.6(c)(2)	Yes.	
§ 63.6(c)(3) and (c)(4)	No	Section reserved.
§ 63.6(c)(5)	Yes.	
§ 63.6(d)	No	Section reserved.
§ 63.6(e)	Yes.	
§ 63.6(e)	Yes	Except as otherwise specified.
§ 63.6(e)(1)(i)	No	See § 63.1274(h) for general duty requirement.
§ 63.6(e)(1)(ii)	No.	
§ 63.6(e)(1)(iii)	Yes.	
§ 63.6(e)(2)	Yes.	
§ 63.6(e)(3)	No.	
§ 63.6(f)(1)	No.	
§ 63.6(f)(2)	Yes.	
§ 63.6(f)(3)	Yes.	
§ 63.6(g)	Yes.	
§ 63.6(h)	No	Subpart HHH does not contain opacity or visible emission standards.
§ 63.6(i)(1) through (i)(14)	Yes.	

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH—Continued

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes.	
§ 63.6(j)	Yes.	
§ 63.7(a)(1)	Yes.	
§ 63.7(a)(2)	Yes	But the performance test results must be submitted within 180 days after the compliance date.
§ 63.7(a)(3)	Yes.	
§ 63.7(b)	Yes.	
§ 63.7(c)	Yes.	
§ 63.7(d)	Yes.	
§ 63.7(e)(1)	No.	
§ 63.7(e)(2)	Yes.	
§ 63.7(e)(3)	Yes.	
§ 63.7(e)(4)	Yes.	
§ 63.7(f)	Yes.	
§ 63.7(g)	Yes.	
§ 63.7(h)	Yes.	
§ 63.8(a)(1)	Yes.	
§ 63.8(a)(2)	Yes.	
§ 63.8(a)(3)	No	Section reserved.
§ 63.8(a)(4)	Yes.	
§ 63.8(b)(1)	Yes.	
§ 63.8(b)(2)	Yes.	
§ 63.8(b)(3)	Yes.	
§ 63.8(c)(1)	Yes.	
63.8(c)(1)(i)	No.	
§ 63.8(c)(1)(ii)	Yes.	
§ 63.8(c)(1)(iii)	Pending.	
§ 63.8(c)(2)	Yes.	
§ 63.8(c)(3)	Yes.	
§ 63.8(c)(4)	No.	
§ 63.8(c)(5) through (c)(8)	Yes.	
§ 63.8(d)	Yes.	
§ 63.8(d)(3)	Yes	Except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.8(e)	Yes	Subpart HHH does not specifically require continuous emissions monitor performance evaluations, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes.	
§ 63.8(f)(6)	No	Subpart HHH does not require continuous emissions monitoring.
§ 63.8(g)	No	Subpart HHH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes.	
§ 63.9(b)(1)	Yes.	
§ 63.9(b)(2)	Yes	Existing sources are given 1 year (rather than 120 days) to submit this notification.
§ 63.9(b)(3)	Yes.	
§ 63.9(b)(4)	Yes.	
§ 63.9(b)(5)	Yes.	
§ 63.9(c)	Yes.	
§ 63.9(d)	Yes.	
§ 63.9(e)	Yes.	
§ 63.9(f)	No.	
§ 63.9(g)	Yes.	
§ 63.9(h)(1) through (h)(3)	Yes.	
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) and (h)(6)	Yes.	
§ 63.9(i)	Yes.	
§ 63.9(j)	Yes.	
§ 63.10(a)	Yes.	
§ 63.10(b)(1)	Yes	Section 63.1284(b)(1) requires sources to maintain the most recent 12 months of data on-site and allows offsite storage for the remaining 4 years of data.
§ 63.10(b)(2)	Yes.	
§ 63.10(b)(2)(i)	No.	
§ 63.10(b)(2)(ii)	No	See § 63.1284(f) for recordkeeping of occurrence, duration, and actions taken during malfunction.
§ 63.10(b)(2)(iii)	Yes.	
§ 63.10(b)(2)(iv) through (b)(2)(v)	No.	
§ 63.10(b)(2)(vi) through (b)(2)(xiv)	Yes.	
§ 63.10(b)(3)	No.	
§ 63.10(c)(1)	Yes.	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) through (c)(8)	Yes.	
§ 63.10(c)(9)	No	Section reserved.

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH—Continued

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.10(c)(10) and (c)(11)	No	See § 63.1284(f)for recordkeeping of malfunctions
§ 63.10(c)(12) through (c)(14)	Yes.	
§ 63.10(c)(15)	No.	
§ 63.10(d)(1)	Yes.	
§ 63.10(d)(2)	Yes.	
§ 63.10(d)(3)	Yes.	
§ 63.10(d)(4)	Yes.	
§ 63.10(d)(5)	No	See § 63.1285(b)(6) for reporting of malfunctions.
§ 63.10(e)(1)	Yes.	
§ 63.10(e)(2)	Yes.	
§ 63.10(e)(3)(i)	Yes	Subpart HHH requires major sources to submit Periodic Reports semi-annually.
§ 63.10(e)(3)(i)(A)	Yes.	
§ 63.10(e)(3)(i)(B)	Yes.	
§ 63.10(e)(3)(i)(C)	No	Subpart HHH does not require quarterly reporting for excess emissions.
§ 63.10(e)(3)(ii) through (e)(3)(viii)	Yes.	
§ 63.10(f)	Yes.	
§ 63.11(a) and (b)	Yes.	
§ 63.11(c), (d), and (e)	Yes.	
§ 63.12(a) through (c)	Yes.	
§ 63.13(a) through (c)	Yes.	
§ 63.14(a) and (b)	Yes.	
§ 63.15(a) and (b)	Yes.	

[FR Doc. 2011–19899 Filed 8–22–11; 8:45 am]

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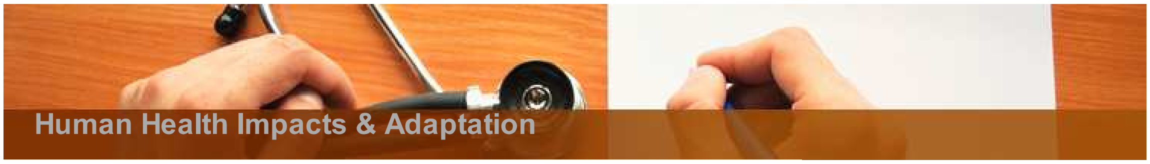
EPA United States Environmental Protection Agency

Climate Change

Human Health Impacts & Adaptation

climatechange/impacts-adaptation/health.html#adapt



Climate Impacts on Human Health

Adaptation Examples in Human Health

Weather and climate play a significant role in people's health. Changes in climate affect the average weather conditions that we are accustomed to. Warmer average temperatures will likely lead to hotter days and more frequent and longer heat waves. This could increase the number of heat-related illnesses and deaths. Increases in the frequency or severity of extreme weather events such as storms could increase the risk of dangerous flooding, high winds, and other direct threats to people and property. Warmer temperatures could increase the concentrations of unhealthy air and water pollutants. Changes in temperature, precipitation patterns, and extreme events could enhance the spread of some diseases.

ON THIS PAGE

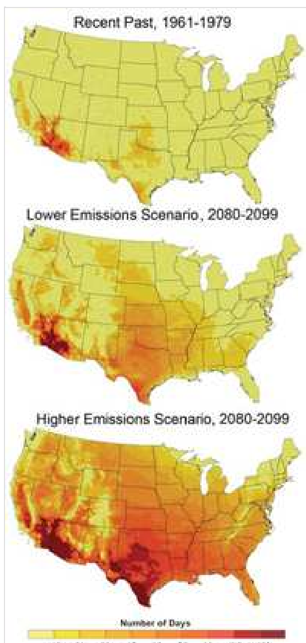
Key Points

- A warmer climate is expected to both increase the risk of heat-related illnesses and death and worsen conditions for air quality.
- Climate change will likely increase the frequency and strength of extreme events (such as floods, droughts, and storms) that threaten human safety and health.
- Climate changes may allow some diseases to spread more easily.

Sun setting over a city on a hot day. Source: EPA (2010)

The impacts of climate change on health will depend on many factors. These factors include the effectiveness of a community's public health and safety systems to address or prepare for the risk and the behavior, age, gender, and economic status of individuals affected. Impacts will likely vary by region, the sensitivity of populations, the extent and length of exposure to climate change impacts, and society's ability to adapt to change.

Although the United States has well-developed public health systems (compared with those of many developing countries), climate change will still likely affect many Americans. In addition, the impacts of climate change on public health around the globe could have important consequences for the United States. For example, more frequent and intense storms may require more disaster relief and declines in agriculture may increase food shortages.



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The number of 100-degree days per year is projected to increase. Source: USGCRP (2009)

Impacts from Heat Waves

Heat waves can lead to heat stroke and dehydration, and are the most common cause of weather-related deaths. [1] [2] Excessive heat is more likely to impact populations in northern latitudes where people are less prepared to cope with excessive temperatures. Young children, older adults, people with medical conditions, and the poor are more vulnerable than others to heat-related illness. The share of the U.S. population composed of adults over age 65 is currently 12%, but is projected to grow to 21% by 2050, leading to a larger vulnerable population. [1]

Climate change will likely lead to more frequent, more severe, and longer heat waves in the summer (see 100-degree-days figure), as well as less severe cold spells in the winter. A recent assessment of the science suggests that increases in heat-related deaths due to climate change would outweigh decreases in deaths from cold-snaps. [1]

Urban areas are typically warmer than their rural surroundings. Climate change could lead to even warmer temperatures in cities. This would increase the demand for electricity in the summer to run air conditioning, which in turn would increase air pollution and greenhouse gas emissions from power plants. The impacts of future heat waves could be especially severe in

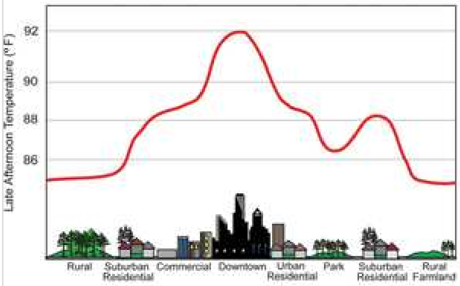
Related Links

EPA:

- Climate Change Indicators in the United States
- Heat Island Effect
- Excessive Heat Events Guidebook
- Global Change Research Program
- Climate Change and Children's Health
- Climate Change and Health Effects on Older Adults
- *Assessment of the Impacts of Global Change on Regional U.S. Air Quality: A Synthesis of Climate Change Impacts on Ground-Level Ozone*
- *Our Nation's Air: Status and Trends Through 2008*

Other:

- CDC Climate Change and Public Health
- USGCRP *Synthesis Assessment Product 4.6: Analyses of the Effects of Global Change on Human Health and Welfare and Human Systems*
- IPCC Fourth Assessment Report, Working Group II EXIT Disclaimer
- USGCRP, Global Climate Change Impacts in the United States: Human Health
- NRC America's Climate Choices: Adapting to the Impacts of Climate Change EXIT Disclaimer
- National Institute of Environmental Health Sciences: *A Human Health Perspective on Climate Change* (PDF)
- World Health Organization, *Climate Change and Human Health: Risks and Responses* EXIT Disclaimer



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The "urban heat island" refers to the fact that the local temperature in urban areas is a few degrees higher than the surrounding area. Source: USGCRP (2009)

large metropolitan areas. For example, in Los Angeles, annual heat-related deaths are projected to increase two- to seven-fold by the end of the 21st century, depending on the future growth of greenhouse gas emissions. [1] Heat waves are also often accompanied by periods of stagnant air, leading to increases in air pollution and the associated health effects

Impacts from Extreme Weather Events

The frequency and intensity of extreme precipitation events is projected to increase in some locations, as is the severity (wind speeds and rain) of tropical storms. [1] These extreme weather events could cause injuries and, in some cases, death. As with heat waves, the people most at risk include young children, older adults, people with medical conditions, and the poor. Extreme events can also indirectly threaten human health in a number of ways. For example, extreme events can:

- Reduce the availability of fresh food and water. [2]
- Interrupt communication, utility, and health care services. [2]
- Contribute to carbon monoxide poisoning from portable electric generators used during and after storms. [2]
- Increase stomach and intestinal illness among evacuees. [1]
- Contribute to mental health impacts such as depression and post-traumatic stress disorder (PTSD). [1]

Flooded streets in New Orleans after Hurricane Katrina in 2005. Source: FEMA (2005)

Climate Change Affects Human Health and Welfare

In 2008, the U.S. Global Change Research Program produced a report that analyzed the impacts of global climate change on human health and welfare. The report finds that:

- Many of the expected health effects are likely to fall mostly on the poor, the very old, the very young, the disabled, and the uninsured.
- Climate change will likely result in regional differences in U.S. impacts, due not only to a regional pattern of changes in climate but also to regional variations in the distribution of sensitive populations and the ability of communities to adapt to climate changes.
- Adaptation should begin now, starting with public health infrastructure. Individuals, communities, and government agencies can take steps to moderate the impacts of climate change on human health. (To learn more, see the Health Adaptation section)

Impacts from Reduced Air Quality

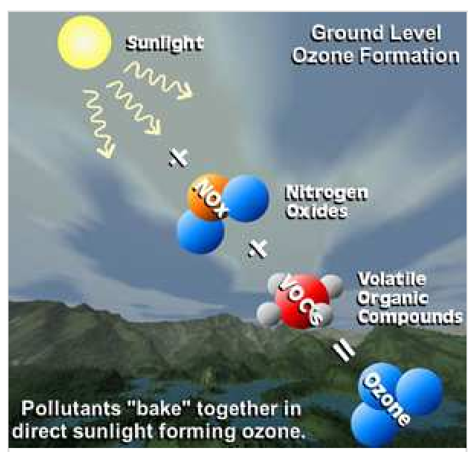
Despite significant improvements in U.S. air quality since the 1970s, as of 2008 more than 126 million Americans lived in counties that did not meet national air quality standards. [3]

Increases in Ozone

Scientists project that warmer temperatures from climate change will increase the frequency of days with unhealthy levels of ground-level ozone, a harmful air pollutant, and a component in smog. [2] [3]

- Ground-level ozone can damage lung tissue and can reduce lung function and inflame airways. This can increase respiratory symptoms and aggravate asthma or other lung diseases. It is especially harmful to children, older adults, outdoor workers, and those with asthma and other chronic lung diseases. [4]
- Ozone exposure also has been associated with increased susceptibility to respiratory infections, medication use, doctor visits, and emergency department visits and hospital admissions for individuals with lung disease. Some studies suggest that ozone may increase the risk of premature mortality, and possibly even the development of asthma. [1] [2] [3] [5]
- Ground-level ozone is formed when certain air pollutants, such as carbon monoxide, oxides of nitrogen (also called NO_X), and volatile organic compounds, are exposed to each other in sunlight. Ground-level ozone is one of the pollutants in smog. [2] [3]
- Because warm, stagnant air tends to increase the formation of ozone, climate change is likely to increase levels of ground-level ozone in already-polluted areas of the United States and increase the number of days with poor air quality. [1] If emissions of air pollutants remain fixed at today's levels until 2050, warming from climate change alone could increase the number of Red Ozone Alert Days (when the air is unhealthy for everyone) by 68% in the 50 largest eastern U.S. cities. [1] (See Box below "EPA Report on Air Quality and Climate Change.")

Smog in Los Angeles decreases visibility and can be harmful to human health. Source: California Air Resources Board (2011)



Ozone chemistry. Source: NASA (2012)

Changes in Fine Particulate Matter

Particulate matter is the term for a category of extremely small particles and liquid droplets suspended in the atmosphere. Fine particles include particles smaller than 2.5 micrometers (about one ten-thousandth of an inch). These particles may be emitted directly or may be formed in the atmosphere from chemical reactions of gases such as sulfur dioxide, nitrogen dioxide, and volatile organic compounds.

- Inhaling fine particles can lead to a broad range of adverse health effects, including premature mortality, aggravation of cardiovascular and respiratory disease, development of chronic lung disease, exacerbation of asthma, and decreased lung function growth in children. [6]
- Sources of fine particle pollution include power plants, gasoline and diesel engines, wood combustion, high-temperature industrial processes such as smelters and steel mills, and forest fires. [6]

Due to the variety of sources and components of fine particulate matter, scientists do not yet know whether climate change will increase or decrease particulate matter concentrations across the United States. [7] [8] A lot of particulate matter is cleaned from the air by rainfall, so increases in precipitation could have a beneficial effect. At the same time, other climate-related changes in stagnant air episodes, wind patterns, emissions from vegetation and the chemistry of atmospheric pollutants will likely affect particulate matter levels. [2] Climate change will also affect particulates through changes in wildfires, which are expected to become more frequent and intense in a warmer climate. [7]

Changes in Allergens

Climate change may affect allergies and respiratory health. [4] The spring pollen season is already occurring earlier in the United States due to climate change. The length of the season may also have increased. In addition, climate change may facilitate the spread of ragweed, an invasive plant with very allergenic pollen. Tests on ragweed show that increasing carbon dioxide concentrations and temperatures would increase the amount and timing of ragweed pollen production. [1] [2] [9]

Impacts from Climate-Sensitive Diseases

Changes in climate may enhance the spread of some diseases. [1] Disease-causing agents, called pathogens, can be transmitted through food, water, and animals such as deer, birds, mice, and insects. Climate change could affect all of these transmitters.

EPA Report on Air Quality and Climate Change

Improving America's air quality is one of EPA's top priorities. EPA's Global Change Research Program is investigating the potential consequences of climate change on U.S. air quality. A recent interim assessment finds that:

- Climate change could increase surface-level ozone concentrations in areas where pollution levels are already high.
- Climate change could make U.S. air quality management more difficult.
- Policy makers should consider the potential impacts of climate change on air quality when making air quality management decisions.

Food-borne Diseases

- Higher air temperatures can increase cases of salmonella and other bacteria-related food poisoning because bacteria grow more rapidly in warm environments. These diseases can cause gastrointestinal distress and, in severe cases, death. [1]
- Flooding and heavy rainfall can cause overflows from sewage treatment plants into fresh water sources. Overflows could contaminate certain food crops with pathogen-containing feces. [1]

Water-borne Diseases

- Heavy rainfall or flooding can increase water-borne parasites such as *Cryptosporidium* and *Giardia* that are sometimes found in drinking water. [1] These parasites can cause gastrointestinal distress and in severe cases, death.
- Heavy rainfall events cause stormwater runoff that may contaminate water bodies used for recreation (such as lakes and beaches) with other bacteria. [9] The most common illness contracted from contamination at beaches is gastroenteritis, an inflammation of the stomach and the intestines that can cause symptoms such as vomiting, headaches, and fever. Other minor illnesses include ear, eye, nose, and throat infections. [2]

Animal-borne Diseases

- The geographic range of ticks that carry Lyme disease is limited by temperature. As air temperatures rise, the range of these ticks is likely to continue to expand northward. [9] Typical symptoms of Lyme disease include fever, headache, fatigue, and a characteristic skin rash.
- In 2002, a new strain of West Nile virus, which can cause serious, life-altering disease, emerged in the United States. Higher temperatures are favorable to the survival of this new strain. [1]


Mosquitoes favor warm, wet climates and can spread diseases such as West Nile virus.

The spread of climate-sensitive diseases will depend on both climate and non-climate factors. The United States has public health infrastructure and programs to monitor, manage, and prevent the spread of many diseases. The risks for climate-sensitive diseases can be much higher in poorer countries that have less capacity to prevent and treat illness. [9] For more information, please visit the International Impacts & Adaptation page.

Other Heath Linkages

Other linkages exist between climate change and human health. For example, changes in temperature and precipitation, as well as droughts and floods, will likely affect agricultural yields and production. In some regions of the world, these impacts may compromise food security and threaten human health through malnutrition, the spread of infectious diseases, and food poisoning. The worst of these effects are projected to occur in developing countries, among vulnerable populations. [9] Declines in human health in other countries might affect the United States through trade, migration and immigration and have implications for national security. [1] [2]

Although the impacts of climate change have the potential to affect human health in the United States and around the world, there is a lot we can do to prepare for and adapt to these changes. Learn about how we can adapt to climate impacts on health.

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EPA United States Environmental Protection Agency

Sulfur Dioxide

Health

Current scientific evidence links short-term exposures to SO_2, ranging from 5 minutes to 24 hours, with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms. These effects are particularly important for asthmatics at elevated ventilation rates (e.g., while exercising or playing.)

Studies also show a connection between short-term exposure and increased visits to emergency departments and hospital admissions for respiratory illnesses, particularly in at-risk populations including children, the elderly, and asthmatics.

EPA's National Ambient Air Quality Standard for SO_2 is designed to protect against exposure to the entire group of sulfur oxides (SOx). SO_2 is the component of greatest concern and is used as the indicator for the larger group of gaseous sulfur oxides (SOx). Other gaseous sulfur oxides (e.g. SO3) are found in the atmosphere at concentrations much lower than SO_2.

Emissions that lead to high concentrations of SO_2 generally also lead to the formation of other SOx. Control measures that reduce SO_2 can generally be expected to reduce people's exposures to all gaseous SOx. This may have the important co-benefit of reducing the formation of fine sulfate particles, which pose significant public health threats.

SOx can react with other compounds in the atmosphere to form small particles. These particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death. EPA's NAAQS for particulate matter (PM) are designed to provide protection against these health effects.

Last updated on Thursday, July 12, 2012

Particulate Matter (PM)

Health

The size of particles is directly linked to their potential for causing health problems. Small particles less than10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream.

Exposure to such particles can affect both your lungs and your heart. Small particles of concern include "inhalable coarse particles" (such as those found near roadways and dusty industries), which are larger than 2.5 micrometers and smaller than 10 micrometers in diameter; and "fine particles" (such as those found in smoke and haze), which are 2.5 micrometers in diameter and smaller.

The Clean Air Act requires EPA to set air quality standards to protect both public health and the public welfare (e.g. visibility, crops and vegetation). Particle pollution affects both.

Health Effects

Particle pollution - especially fine particles - contains microscopic solids or liquid droplets that are so small that they can get deep into the lungs and cause serious health problems. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including:

- premature death in people with heart or lung disease,
- nonfatal heart attacks,
- irregular heartbeat,
- aggravated asthma,
- decreased lung function, and
- increased respiratory symptoms, such as irritation of the airways, coughing or difficulty breathing.

People with heart or lung diseases, children and older adults are the most likely to be affected by particle pollution exposure. However, even if you are healthy, you may experience temporary symptoms from exposure to elevated levels of particle pollution. For more information about asthma, visit www.epa.gov/asthma.

Environmental Effects

Visibility impairment
Fine particles ($PM_{2.5}$) are the main cause of reduced visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas. For more information about visibility, visit www.epa.gov/visibility.

Environmental damage
Particles can be carried over long distances by wind and then settle on ground or water. The effects of this settling include: making lakes and streams acidic; changing the nutrient balance in coastal waters and large river basins; depleting the nutrients in soil; damaging sensitive forests and farm crops; and affecting the diversity of ecosystems. More information about the effects of particle pollution and acid rain.

Aesthetic damage
Particle pollution can stain and damage stone and other materials, including culturally important objects such as statues and monuments. More information about the effects of particle pollution and acid rain.

For more information on particle pollution, health and the environment, visit:

Particle Pollution and Your Health (PDF) (2pp, 320k): Learn who is at risk from exposure to particle pollution, what health effects you may experience as a result of particle exposure, and simple measures you can take to reduce your risk.

How Smoke From Fires Can Affect Your Health: It's important to limit your exposure to smoke -- especially if you may be susceptible. This publication provides steps you can take to protect your health.

Integrated Science Assessment for Particulate Matter (December 2009): This comprehensive assessment of scientific data about the health and environmental effects of particulate matter is an important part of EPA's review of its particle pollution standards.

Last updated on Friday, June 15, 2012

United States Environmental Protection Agency

Visibility

Basic Information

How far can you see?

Every year there are over 280 million visitors to our nation's most treasured parks and wilderness areas. Unfortunately, many visitors aren't able to see the spectacular vistas they expect. During much of the year a veil of white or brown haze hangs in the air blurring the view. Most of this haze is not natural. It is air pollution, carried by the wind often many hundreds of miles from where it originated.

In our nation's scenic areas, the visual range has been substantially reduced by air pollution. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles. In the West, visual range has decreased from 140 miles to 35-90 miles.

What is haze?

Haze is caused when sunlight encounters tiny pollution particles in the air. Some light is absorbed by particles. Other light is scattered away before it reaches an observer. More pollutants mean more absorption and scattering of light, which reduce the clarity and color of what we see. Some types of particles such as sulfates, scatter more light, particularly during humid conditions.

Where does haze-forming pollution come from?

Air pollutants come from a variety of natural and manmade sources. Natural sources can include windblown dust, and soot from wildfires. Manmade sources can include motor vehicles, electric utility and industrial fuel burning, and manufacturing operations. Particulate matter pollution is the major cause of reduced visibility (haze) in parts of the United States, including many of our national parks. Find out more about particulate pollution.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are carried many miles from the source of the pollutants.

What else can these pollutants do to you and the environment?

Some of the pollutants which form haze have also been linked to serious health problems and environmental damage. Exposure to very small particles in the air have been linked with increased respiratory illness, decreased lung function, and even premature death. In addition, particles such as nitrates and sulfates contribute to acid rain formation which makes lakes, rivers, and streams unsuitable for many fish, and erodes buildings, historical monuments, and paint on cars.

How can I learn more about visibility?

How Air Pollution Affects the View (PDF) (2 pp, 793 KB) - EPA brochure describing the health and environmental effects of haze.

Introduction to Visibility (PDF) (79 pp., 3.3 MB) - Report by William Malm, National Park Service and Colorodo State Institute for Research on the Atmosphere

What other Federal agencies address visibility?

- National Park Service EXIT Disclaimer
- U.S. Forest Service EXIT Disclaimer
- U.S. Fish and Wildlife Service EXIT Disclaimer

Last updated on Thursday, May 31, 2012

DOE/EIA-0581(2009)

The National Energy Modeling System: An Overview 2009

October 2009

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

This publication is on the WEB at:
www.eia.doe.gov/oiaf/aeo/overview/

Preface

The National Energy Modeling System: An Overview 2009 provides a summary description of the National Energy Modeling System, which was used to generate the projections of energy production, demand, imports, and prices through the year 2030 for the *Annual Energy Outlook 2009, (DOE/EIA-0383(200*9)), released in March 2009. *AEO2009* presents national projections of energy markets for five primary cases—a reference case and four additional cases that assume higher and lower economic growth and higher and lower world oil prices than in the reference case. The Overview presents a brief description of the methodology and scope of each of the component modules of NEMS. The model documentation reports listed in the appendix of this document provide further details.

The Overview was prepared by the Energy Information Administration, Office of Integrated Analysis and Forecasting under the direction of John J. Conti (john.conti@eia.doe.gov, 202/586-2222), Director, Office of Integrated Analysis and Forecasting; Paul D. Holtberg (paul.holtberg@eia.doe.gov, 202/586-1284), Director of the Demand and Integration Division; Joseph A. Beamon (jbeamon@eia.doe.gov, 202/586-2025), Director of the Coal and Electric Power Division; A. Michael Schaal (michael,schaal@eia.doe.gov, 202/586-5590), Director of the Oil and Gas Division; Glen E. Sweetnam (glen.sweetnam@eia.doe.gov, 202-586-2188), Director, International, Economic, and Greenhouse Gases Division; and Andy S. Kydes (akydes@eia.doe.gov, 202/586-2222), Senior Technical Advisor.

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AEO2009 is available on the EIA Home Page on the Internet (http://www.eia.doe.gov/oiaf/aeo/index.html). Assumptions underlying the projections are available in Assumptions to the Annual Energy Outlook 2009 at http://www.eia.doe.gov/oiaf/aeo/assumption/index.html. Tables of regional projections and other underlying details of the reference case are available at http://www.eia.doe.gov/oiaf/aeo/supplement/index.html. Model documentation reports and The National Energy Modeling System: An Overview 2009 are also available on the Home Page at http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model documentation.

For ordering information and for questions on energy statistics, please contact EIA's National Energy Information Center.

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Introduction

Introduction

The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system of U.S. through 2030. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS was designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE).

The National Energy Modeling System: An Overview 2009 provides an overview of the structure and methodology of NEMS and each of its components. This chapter provides a description of the design and objectives of the system, followed by a chapter on the overall modeling structure and solution algorithm. The remainder of the report summarizes the methodology and scope of the component modules of NEMS. The model descriptions are intended for readers familiar with terminology from economic, operations research, and energy modeling. More detailed model documentation reports for all the NEMS modules are also available from EIA (Appendix, “Bibliography”).

Purpose of NEMS

NEMS is used by EIA to project the energy, economic, environmental, and security impacts on the United States of alternative energy policies and different assumptions about energy markets. The projection horizon is approximately 25 years into the future. The projections in *Annual Energy Outlook 2009 (AEO2009)* are from the present through 2030. This time period is one in which technology, demographics, and economic conditions are sufficiently understood in order to represent energy markets with a reasonable degree of confidence. NEMS provides a consistent framework for representing the complex interactions of the U.S. energy system and its response to a wide variety of alternative assumptions and policies or policy initiatives. As an annual model, NEMS can also be used to examine the impact of new energy programs and policies.

Energy resources and prices, the demand for specific energy services, and other characteristics of energy markets vary widely across the United States. To address these differences, NEMS is a regional model. The regional disaggregation for each module reflects the availability of data, the regional format typically used to analyze trends in the specific area, geology, and other factors, as well as the regions determined to be the most useful for policy analysis. For example, the demand modules (e.g., residential, commercial, industrial and transportation) use the nine Census divisions, the Electricity Market Module uses 15 supply regions based on the North American Electric Reliability Council (NERC) regions, the Oil and Gas Supply Modules use 12 supply regions, including 3 offshore and 3 Alaskan regions, and the Petroleum Market Module uses 5 regions based on the Petroleum Administration for Defense Districts.

Baseline projections are developed with NEMS and published annually in the *Annual Energy Outlook (AEO)*. In accordance with the requirement that EIA remain policy-neutral, the *AEO* projections are generally based on Federal, State, and local laws and regulations in affect at the time of the projection. The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require implementing regulations or appropriations of funds that have not been provided or specified in the legislation itself—are not reflected in NEMS. The first version of NEMS, completed in December 1993, was used to develop the projections presented in the *Annual Energy Outlook 1994*. This report describes the version of NEMS used for the *AEO2009*.[1]

The projections produced by NEMS are not considered to be statements of what will happen but of what might happen, given the assumptions and methodologies used. Assumptions include, for example, the estimated size of the economically recoverable resource base of fossil fuels, and changes in world energy supply and demand. The projections are business-as-usual trend estimates, given known technological and demographic trends.

Analytical Capability

NEMS can be used to analyze the effects of existing and proposed government laws and regulations related to energy production and use; the potential impact of new and advanced energy production, conversion, and consumption technologies; the impact and cost of greenhouse gas control; the impact of increased use of renewable energy sources; and the potential savings

1 Energy Information Administration, *Annual Energy Outlook 2009,* DOE/EIA-0383(2009) (Washington, DC, March 2009)

from increased efficiency of energy use; and the impact of regulations on the use of alternative or reformulated fuels.

In addition to producing the analyses in the *AEO*, NEMS is used for one-time analytical reports and papers, such as *An Updated Annual Energy Outlook 2009 Reference Case Reflecting Provisions of the American Recovery and Reinvestment Act and Recent Changes in the Economic Outlook*,[2] which updates the *AEO2009* reference case to reflect the enactment of the American Recovery and Reinvestment Act in February 2009 and to adopt a revised macroeconomic outlook for the U.S. and global economies. The revised *AEO2009* reference case will be used as the starting point for pending and future analyses of proposed energy and environmental legislation. Other analytical papers, which either describe the assumptions and methodology of the NEMS or look at current energy markets issues, are prepared using the NEMS. Many of these papers are published in the Issues In Focus section of the *AEO*. Past and current analyses are available at http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_analyes.html.

NEMS has also been used for a number of special analyses at the request of the Administration, U.S. Congress, other offices of DOE and other government agencies, who specify the scenarios and assumptions for the analysis. Some recent examples include:

- *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009*,[3] requested by Chairman Henry Waxman and Chairman Edward Markey to analyze the impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (ACESA), which was passed by the House of Representatives on June 26, 2009. ACESA is a complex bill that regulates emissions of greenhouse gases through market-based mechanisms, efficiency programs, and economic incentives.
- *Impacts of a 25-Percent Renewable Electricity Standard as Proposed in the American Clean Energy and Security Act*,[4] requested by Senator Markey to analyze the effects of a 25-percent Federal renewable electricity standard (RES) as included in the discussion draft of broader legislation, the American Clean Energy and Security Act.
- *Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues*,[5] requested by Senator Sessions *to* analyze the environmental and energy efficiency attributes of diesel-fueled light-duty vehicles (LDV's), including comparison of the characteristics of the vehicles with those of similar gasoline-fueled, E85-fueled, and hybrid vehicles, as well as a discussion of any technical, economic, regulatory, or other obstacles to increasing the use of diesel-fueled vehicles in the United States.
- *The Impact of Increased Use of Hydrogen on Petroleum Consumption and Carbon Dioxide Emissions*,[6] requested by Senator Dorgan to analyze the impacts on U.S. energy import dependence and emissions reductions resulting from the commercialization of advanced hydrogen and fuel cell technologies in the transportation and distributed generation markets.
- *Analysis of Crude Oil Production in the Arctic National Wildlife Refuge*,[7] requested by Senator Stevens to access the impact of Federal oil and natural gas leasing in the coastal plain of the Arctic National Wildlife Refuge in Alaska.
- *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of*

2 Energy Information Administration, *An Updated Annual Energy Outlook 2009 Reference Case Reflecting Provisions of the American Recovery and Reinvestment Act and Recent Changes in the Economic Outlook*, SR/OIAF/2009-4 (Washington, DC, April 2009).

3 Energy Information Administration, Energy Market and Economic Impacts of H.R. 2454, the American Clean energy and Security Act of 2009, SR/OIAF/2009-05 (Washington, DC, August 2009).

4 Energy Information Administration, *Impacts of a 25-Percent Renewable Electricity Standard as proposed in the American Clean Energy and Security Act Discussion*, SR/OIAF/2009-03 (Washington, DC, April 2009)

5 Energy Information Administration, *Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues*, SR/OIAF/2009-02 (Washington, DC, February 2009).

6 Energy Information Administration, *The Impact of Increased Use of Hydrogen on Petroleum Consumption and Carbon Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues*, SR/OIAF/2008-04 (Washington, DC, September 2008).

7 Energy Information Administration, *Analysis of Crude Oil Production in the Arctic National Wildlife Refuge*, SR/OIAF/2008-03 (Washington, DC, May 2008).

2007,[8] requested by Senators Lieberman, Warner, Inhofe, Voinovich, and Barrasso to analyze the impacts of the greenhouse gas cap-and-trade program that would be established under Title I of S.2191.

- *Energy Market and Economic Impact*s of S.1766, the Low Carbon Economy Act of 2007,[9] requested by Senators Bingaman and Specter to analyze the impact of the mandatory greenhouse gas allowance program under S.1766 designed to maintain covered emissions at approximately 2006 levels in 2020, 1990 levels in 2030, and at least 60 percent below 1990 levels by 2050.

Representations of Energy Market Interactions

NEMS is designed to represent the important interactions of supply and demand in U.S. energy markets. In the United States, energy markets are driven primarily by the fundamental economic interactions of supply and demand. Government regulations and policies can exert considerable influence, but the majority of decisions affecting fuel prices and consumption patterns, resource allocation, and energy technologies are made by private individuals who value attributes other than life cycle costs or companies attempting to optimize their own economic interests. NEMS represents the market behavior of the producers and consumers of energy at a level of detail that is useful for analyzing the implications of technological improvements and policy initiatives.

Energy Supply/Conversion/Demand Interactions

NEMS is a modular system. Four end-use demand modules represent fuel consumption in the residential, commercial, transportation, and industrial sectors, subject to delivered fuel prices, macroeconomic influences, and technology characteristics. The primary fuel supply and conversion modules compute the levels of domestic production, imports, transportation costs, and fuel prices that are needed to meet domestic and export demands for energy, subject to resource base characteristics, industry infrastructure and technology, and world market conditions. The modules interact to solve for the economic supply and demand balance for each fuel. Because of the modular design, each sector can be represented with the methodology andthe level of detail, including regional detail, appropriate for that sector. The modularity also facilitates the analysis, maintenance, and testing of the NEMS component modules in the multi-user environment.

Domestic Energy System/Economy Interactions

The general level of economic activity, represented by gross domestic product, has traditionally been used as a key explanatory variable or driver for projections of energy consumption at the sectoral and regional levels. In turn, energy prices and other energy system activities influence economic growth and activity. NEMS captures this feedback between the domestic economy and the energy system. Thus, changes in energy prices affect the key macroeconomic variables—such as gross domestic product, disposable personal income, industrial output, housing starts, employment, and interest rates—that drive energy consumption and capacity expansion decisions.

Domestic/World Energy Market Interactions

World oil prices play a key role in domestic energy supply and demand decision making and oil price assumptions are a typical starting point for energy system projections. The level of oil production and consumption in the U.S. energy system also has a significant influence on world oil markets and prices. In NEMS, an international module represents the response of world oil markets (supply and demand) to assumed world oil prices. The results/outputs of the module are international liquids consumption and production by region, and a crude oil supply curve representing international crude oil similar in quality to West Texas Intermediate that is available to U.S. markets through the Petroleum Market Module (PMM) of NEMS. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international liquids supply and demand, current investment trends in exploration and development, and long-term resource economics for 221 countries/territories. The oil production estimates include both conventional and unconventional supply recovery technologies.

8 Energy Information Administration, *Energy Market and Economic Impacts of S.2191, the Lieberan-Warner Climate Security Act of 2007*, SR/OIAF/2008-01 (Washington, DC, April 2008).

9 Energy Information Administration, *Energy Market and Economic Impacts of S.1766, the Low Carbon Economy Act of 2007*, SR/OIAF/2007-06 (Washington, DC, January 2008).

Economic Decision Making Over Time

The production and consumption of energy products today are influenced by past investment decisions to develop energy resources and acquire energy-using capital stock. Similarly, the production and consumption of energy in a future time period will be influenced by decisions made today and in the past.

Current investment decisions depend on expectations about future markets. For example, expectations of rising energy prices in the future increase the likelihood of current decisions to invest in more energy-efficient technologies or alternative energy sources. A variety of assumptions about planning horizons, the formation of expectations about the future, and the role of those expectations in economic decision making are applied within the individual NEMS modules.

Technology Representation

A key feature of NEMS is the representation of technology and technology improvement over time. Five of the sectors—residential, commercial, transportation, electricity generation, and refining—include extensive treatment of individual technologies and their characteristics, such as the initial capital cost, operating cost, date of availability, efficiency, and other characteristics specific to the particular technology. For example, technological progress in lighting technologies results in a gradual reduction in cost and is modeled as a function of time in these end-use sectors. In addition, the electricity sector accounts for technological optimism in the capital costs of first-of-a-kind generating technologies and for a decline in cost as experience with the technologies is gained both domestically and internationally. In each of these sectors, equipment choices are made for individual technologies as new equipment is needed to meet growing demand for energy services or to replace retired equipment.

In the other sectors—industrial, oil and gas supply, and coal supply—the treatment of technologies is more limited due to a lack of data on individual technologies. In the industrial sector, only the combined heat and power and motor technologies are explicitly considered and characterized. Cost reductions resulting from technological progress in combined heat and power technologies are represented as a function of time as experience with the technologies grows. Technological progress is not explicitly modeled for the industrial motor technologies. Other technologies in the energy-intensive industries are represented by technology bundles, with technology possibility curves representing efficiency improvement over time. In the oil and gas supply sector, technological progress is represented by econometrically estimated improvements in finding rates, success rates, and costs. Productivity improvements over time represent technological progress in coal production.

External Availability

In accordance with EIA requirements, NEMS is fully documented and archived. EIA has been running NEMS on four EIA terminal servers and several dual-processor personal computers (PCs) using the Windows XP operating system. The archive file provides the source language, input files, and output files to replicate the *Annual Energy Outlook* reference case runs on an identically equipped computer; however, it does not include the proprietary portions of the model, such as the IHS Global Insight, Inc. (formerly DRI-WEFA) macroeconomic model and the optimization modeling libraries. NEMS can be run on a high-powered individual PC as long as the required proprietary software resides on the PC. Because of the complexity of NEMS, and the relatively high cost of the proprietary software, NEMS is not widely used outside of the Department of Energy. However, NEMS, or portions of it, is installed at the Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, the Electric Power Research Institute, the National Energy Technology Laboratory, the National Renewable Energy Laboratory, several private consulting firms, and a few universities.

Overview of NEMS

Overview of NEMS

NEMS explicitly represents domestic energy markets by the economic decision making involved in the production, conversion, and consumption of energy products. Where possible, NEMS includes explicit representation of energy technologies and their characteristics. Since energy costs, availability, and energy-consuming characteristics vary widely across regions, considerable regional detail is included. Other details of production and consumption are represented to facilitate policy analysis and ensure the validity of the results. A summary of the detail provided in NEMS is shown in Table 1.

Table 1. Characteristics of Selected Modules

Energy Activity	Categories	Regions
Residential Demand	Twenty four end-use services Three housing types Fifty end-use technologies	Nine Census divisions
Commercial demand	Ten end-use services Eleven building types Eleven distributed generation technologies Sixty-three end-use technologies	Nine Census divisions
Industrial demand	Seven energy-intensive industries Eight non-energy-intensive industries Six non-manufacturing industries Cogeneration	Four Census regions, shared to nine Census divisions
Transportation demand	Six car sizes Six light truck sizes Sixty-three conventional fuel-saving technologies for light-duty vehicles Gasoline, diesel, and fourteen alternative-fuel vehicle technologies for light-duty vehicles Twenty vintages for light-duty vehicles Regional, narrow, and wide-body aircraft Six advanced aircraft technologies Light, medium, and heavy freight trucks Thirty-seven advanced freight truck technologies	Nine Census divisions
Electricity	Eleven fossil generation technologies Two distributed generation technologies Eight renewable generation technologies Conventional and advanced nuclear Storage technology to model load shifting Marginal and average cost pricing Generation capacity expansion Seven environmental control technologies	Fifteen electricity supply regions (including Alaska and Hawaii) based on the North American Electric Reliability Council regions and subregions Nine Census divisions for demand Fifteen electricity supply regions
Renewables	Two wind technologies—onshore and offshore—, geothermal, solar thermal, solar photovoltaic, landfill gas, biomass, conventional hydropower	
Oil supply	Lower-48 onshore Lower-48 deep and shallow offshore Alaska onshore and offshore	Six lower 48 onshore regions Three lower 48 offshore regions Three Alaska regions
Natural gas supply	Conventional lower-48 onshore Lower-48 deep and shallow offshore Coalbed methane Gas shales Tight sands	Six lower 48 onshore regions Three lower 48 offshore regions Three Alaska regions
Natural gas transmission and distribution	Core vs. noncore delivered prices Peak vs. off-peak flows and prices Pipeline capacity expansion Pipeline and distributor tariffs Canada, Mexico, and LNG imports and exports Alaska gas consumption and supply	Twelve lower 48 regions Ten pipeline border points Eight LNG import regions
Refining	Five crude oil categories Fourteen product categories More than 40 distinct technologies Refinery capacity expansion	Five refinery regions based on the Petroleum Administration for Defense Districts
Coal supply	Three sulfur categories Four thermal categories Underground and surface mining types Imports and Exports	Fourteen supply regions Fourteen demand regions Seventeen export regions Twenty import regions

Major Assumptions

Each module of NEMS embodies many assumptions and data to characterize the future production, conversion, or consumption of energy in the United States. Two of the more important factors influencing energy markets are economic growth and oil prices.

The *AEO2009* includes five primary fully-integrated cases: a reference case, high and low economic growth cases, and high and low oil price cases. The primary determinant for different economic growth rates are assumptions about growth in the labor force and productivity, while the long-term oil price paths are based on access to and cost of oil from the non-Organization of Petroleum Exporting Countries (OPEC), OPEC supply decisions, and the supply potential of unconventional liquids, as well as the demand for liquids.

In addition to the five primary fully-integrated cases, *AEO2009* includes 34 other cases that explore the impact of varying key assumptions in the individual components of NEMS. Many of these cases involve changes in the assumptions that impact the penetration of new or improved technologies, which is a major uncertainty in formulating projections of future energy markets. Some of these cases are run as fully integrated cases (e.g., integrated 2009 technology case, integrated high technology case, low and high renewables technology cost cases, slow and rapid oil and gas technology cases, and low and high coal cost cases). Others exploit the modular structure of NEMS by running only a portion of the entire modeling system in order to focus on the first-order impacts of changes in the assumptions (e.g., 2009, high, and best available technology cases in the residential and commercial sectors, 2009 and high technology cases in the industrial sector and, low and high technology cases in the transportation sector).

NEMS Modular Structure

Overall, NEMS represents the behavior of energy markets and their interactions with the U.S. economy. The model achieves a supply/demand balance in the end-use demand regions, defined as the nine Census divisions (Figure 1), by solving for the prices of each energy type that will balance the quantities producers are willing to supply with the quantities consumers wish to consume. The system reflects market economics, industry structure, and existing energy policies and regulations that influence market behavior.

NEMS consists of four supply modules (oil and gas, natural gas transmission and distribution, coal market, and renewable fuels); two conversion modules (electricity market and petroleum market); four end-use demand modules (residential demand, commercial demand, industrial demand, and transportation demand); one module to simulate energy/economy interactions (macroeconomic activity); one module to simulate international energy markets (international energy); and one module that provides the mechanism to achieve a general market equilibrium among all the other modules (integrating module). Figure 2 depicts the high-level structure of NEMS.

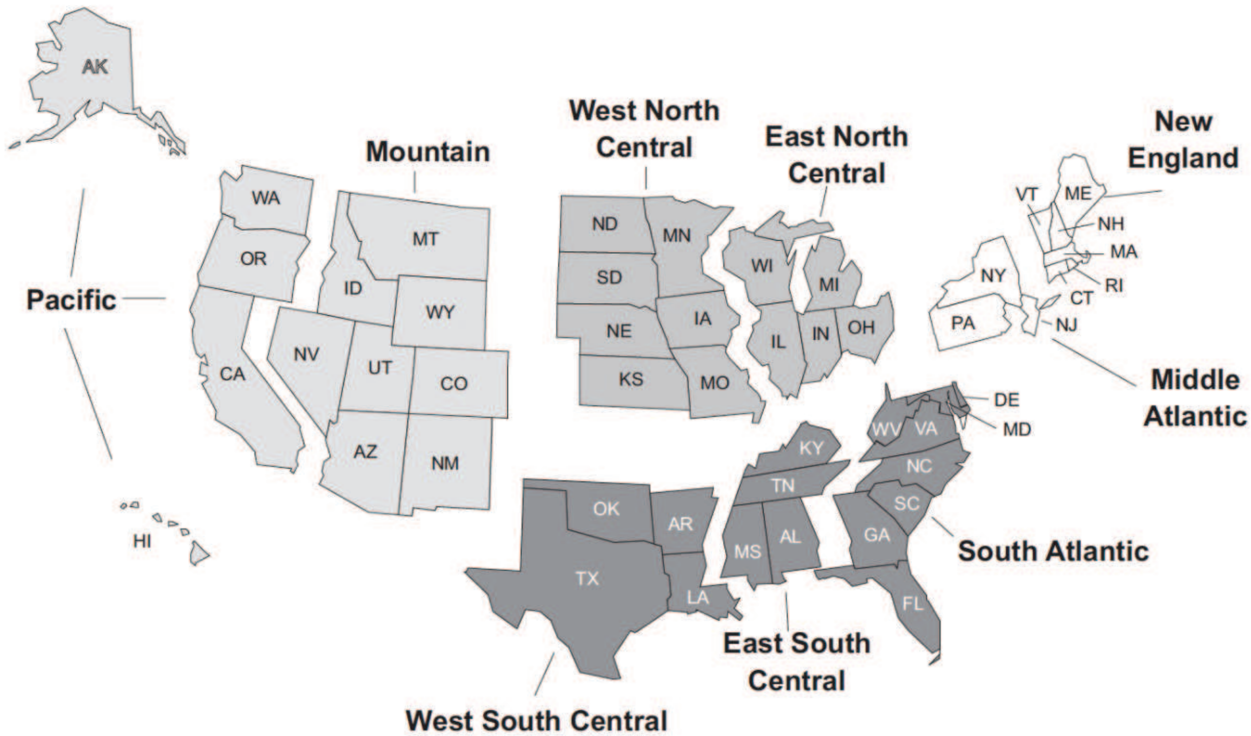
Because energy markets are heterogeneous, a single methodology does not adequately represent all supply, conversion, and end-use demand sectors. The modularity of the NEMS design provides the flexibility for each component of the U.S. energy system to use the methodology and coverage that is most appropriate. Furthermore, modularity provides the capability to execute the modules individually or in collections of modules, which facilitates the development and analysis of the separate component modules. The interactions among these modules are controlled by the integrating module.

The NEMS global data structure is used to coordinate and communicate the flow of information among the modules. These data are passed through common interfaces via the integrating module. The global data structure includes energy market prices and consumption; macroeconomic variables; energy production, transportation, and conversion information; and centralized model control variables, parameters, and assumptions. The global data structure excludes variables that are defined locally within the modules and are not communicated to other modules.

A key subset of the variables in the global data structure is the end-use prices and quantities of fuels that are used to equilibrate the NEMS energy balance in the convergence algorithm. These delivered prices of energy and the quantities demanded are defined by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The regions used for the price and quantity variables in the global data structure are the nine Census divisions. The four Census regions (shown in Figure 1 by breaks between State groups) and nine Census divisions are a common, mainstream level of regionality widely used by EIA and other organizations for data collection and analysis.

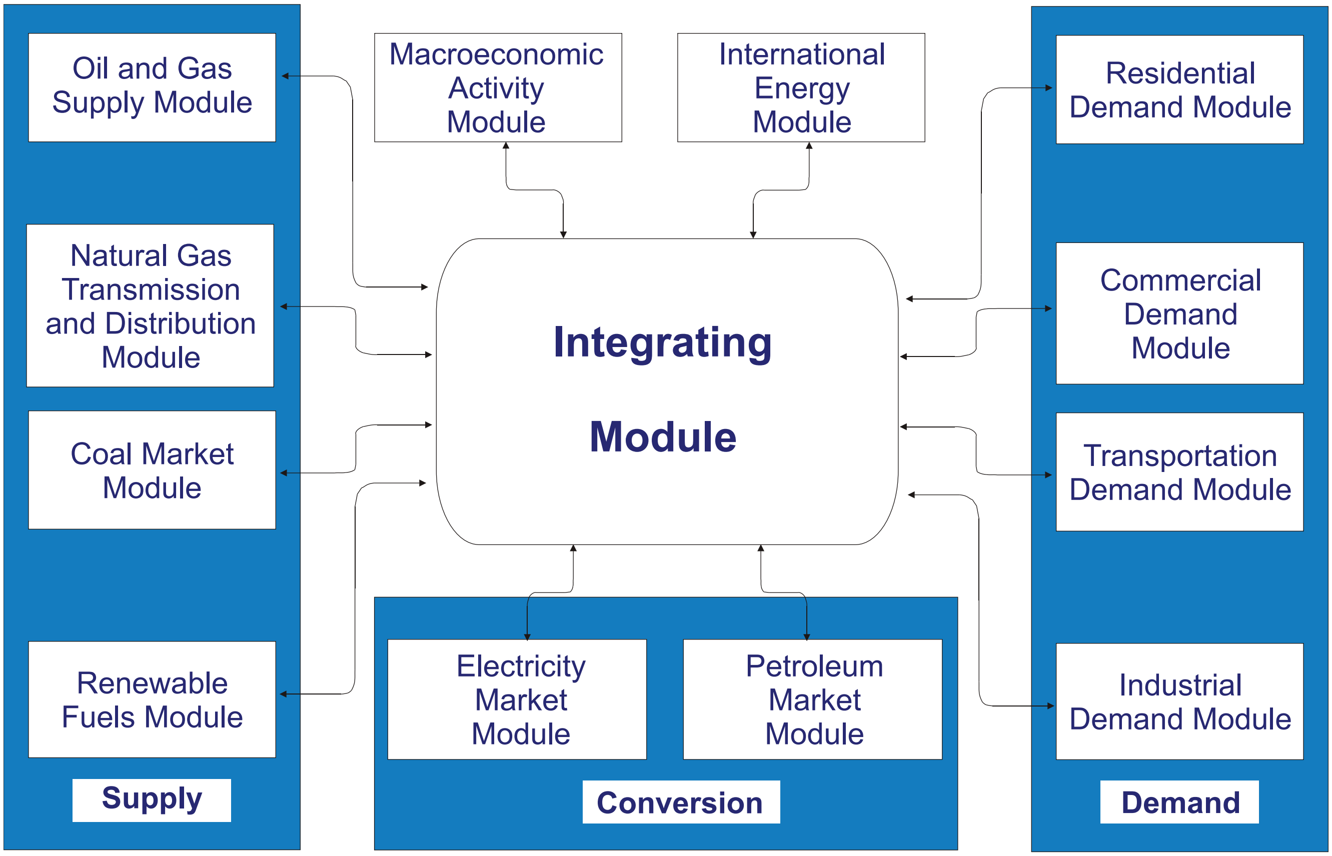
Overview of NEMS

Figure 1. Census Division



Division 1	Division 3	Division 5	Division 7	Division 9
New England	**East North Central**	**South Atlantic**	**West South Central**	**Pacific**
Connecticut	Illinois	Delaware	Arkansas	Alaska
Maine	Indiana	District of Columbia	Louisiana	California
Massachusetts	Michigan	Florida	Oklahoma	Hawaii
New Hampshire	Ohio	Georgia	Texas	Oregon
Rhode Island	Wisconsin	Maryland		Washington
Vermont		North Carolina	**Division 8**	
	Division 4	South Carolina	**Mountain**	
Division 2	**West North Central**	Virginia	Arizona	
Middle Atlantic	Iowa	West Virginia	Colorado	
New Jersey	Kansas		Idaho	
New York	Minnesota	**Division 6**	Montana	
Pennsylvania	Missouri	**East South Central**	Nevada	
	Nebraska	Alabama	New Mexico	
	North Dakota	Kentucky	Utah	
	South Dakota	Mississippi	Wyoming	
		Tennessee		

Figure 2. National Energy Modeling System



Integrating Module

The NEMS integrating module controls the entire NEMS solution process as it iterates to determine a general market equilibrium across all the NEMS modules. It has the following functions:

- Manages the NEMS global data structure
- Executes all or any of the user-selected modules in an iterative convergence algorithm
- Checks for convergence and reports variables that remain out of convergence
- Implements convergence relaxation on selected variables between iterations to accelerate convergence
- Updates expected values of the key NEMS variables.

The integrating module executes the demand, conversion, and supply modules iteratively until it achieves an economic equilibrium of supply and demand in all the consuming and producing sectors. Each module is called in sequence and solved, assuming that all other variables in the energy markets are fixed. The modules are called iteratively until the end-use prices and quantities remain constant within a specified tolerance, a condition defined as convergence. Equilibration is achieved annually throughout the projection period, currently through 2030, for each of the nine Census divisions.

In addition, the macroeconomic activity and international energy modules are executed iteratively to incorporate the feedback on the economy and international energy markets from changes in the domestic energy markets. Convergence tests check the stability of a set of key macroeconomic and international trade variables in response to interactions with the domestic energy system.

The NEMS algorithm executes the system of modules until convergence is reached. The solution procedure for one iteration involves the execution of all the component modules, as well as the updating of expectation variables (related to foresight assumptions) for use in the next iteration. The system is executed sequentially for each year in the projection period. During each iteration, the modules are executed in turn, with intervening convergence checks that isolate specific modules that are not converging. A convergence check is made for each price and quantity variable to see whether the percentage change in the variable is within the assumed tolerance. To avoid unnecessary iterations for changes in insignificant values, the quantity convergence check is omitted for quantities less than a user-specified minimum level. The order of execution of the modules may affect the rate of convergence but will generally not prevent convergence to an equilibrium solution or significantly alter the results. An optional relaxation routine can be executed to dampen swings in solution values between iterations. With this option, the current iteration values are reset partway between solution values from the current and previous iterations. Because of the modular structure of NEMS and the iterative solution algorithm, any single module or subset of modules can be executed independently. Modules not executed are bypassed in the calling sequence, and the values they would calculate and provide to the other modules are held fixed at the values in the global data structure, which are the solution values from a previous run of NEMS. This flexibility is an aid to independent development, debugging, and analysis.

Carbon Dioxide Emissions

Carbon Dioxide Emissions

The emissions policy submodule, part of the integrating module, estimates energy-related carbon dioxide emissions and is capable of representing two related greenhouse gas (GHG) emissions policies: a cap-and-trade program and a carbon dioxide emission tax.

Carbon dioxide emissions are calculated from fossil-fuel energy consumption and fuel-specific emissions factors. The estimates are adjusted for carbon capture technologies where applicable. Carbon dioxide emissions from energy use are dependent on the carbon content of the fossil fuel, the fraction of the fuel consumed in combustion, and the consumption of that fuel. The product of the carbon content at full combustion and the combustion fraction yields an adjusted carbon emission factor. The adjusted carbon emissions factors, one for each fuel and sector, are provided as input to the emissions policy module.

Data on past carbon dioxide emissions and emissions factors are updated each year from the EIA's annual inventory, *Emissions of Greenhouse Gases the United States*.[10] To provide a more complete accounting of greenhouse gas emissions consistent with that inventory, a baseline emissions projection for the non-energy carbon dioxide and other greenhouse gases may be specified as an exogenous input.

To represent carbon tax or cap-and-trade policies, an incremental cost of using each fossil fuel, on a dollar-per-Btu basis, is calculated based the carbon dioxide emissions factors and the per-ton carbon dioxide tax or cap-and-trade allowance cost. This incremental cost, or carbon price adjustment, is added to the corresponding energy prices as seen by the energy demand modules. These price adjustments influence energy demand and energy-related CO_2 emissions, as well as macroeconomic trends.

Under a cap-and-trade policy, the allowance or permit price is determined in an iterative solution process such that the annual covered emissions match the cap each year. If allowance banking is permitted, a constant-growth allowance price path is found such that cumulative emissions over the banking interval match the cumulative covered emissions. To the extent the policies cover greenhouse gases other than CO_2, the coverage assumptions and abatement potential for the gases must be provided as input. In past studies, EIA has drawn on work by the Environmental Protection Agency (EPA) to represent exogenous estimates of emissions abatement and the use of offsets as a function of allowance prices.

Representing specific cap-and-trade policies in NEMS almost always requires customization of the model. Among the issues that must be addressed are what gases and sectors are covered, what offsets are eligible as compliance measures, how the revenues raised by the taxes or allowance sales are used, how allowances or the value of allowances are distributed, and how the distribution affects energy pricing or the cost of using energy.

10 Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2007*, DOE/EIA-0573 (2007) (Washington, DC, December 2008), web site www.eia.doe.gov/oiaf/1605/ggrpt/index.html.

Macroeconomic Activity Module

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) links NEMS to the rest of the economy by providing projections of economic driver variables for use by the supply, demand, and conversion modules of NEMS. The derivation of the baseline macroeconomic projection lays a foundation for the determination of the energy demand and supply forecast. MAM is used to present alternative macroeconomic growth cases to provide a range of uncertainty about the growth potential for the economy and its likely consequences for the energy system. MAM is also able to address the macroeconomic impacts associated with changing energy market conditions, such as alternative world oil price assumptions. Outside of the *AEO* setting, MAM represents a system of linked modules which can assess the potential impacts on the economy of changes in energy events or policy proposals. These economic impacts then feed back into NEMS for an integrated solution. MAM consists of five submodules:

- Global Insight Model of the U.S. Economy
- Global Insight Industry Model
- Global Insight Employment Model
- EIA Regional Model
- EIA Commercial Floorspace Model

The IHS Global Insight Model of the U.S. Economy (Macroeconomic Model) is the same model used by IHS Global Insight, Inc. to generate the economic projections behind the company's monthly assessment of the U.S. economy. The Industry and Employment submodules, are derivatives of IHS Global Insight's Industry and Employment Models, and have been tailored to provide the industry and regional detail required by NEMS. The Regional and Commercial Floorspace Submodules were developed by EIA to complement the set of Global Insight models, providing a fully integrated approach to projecting economic activity at the national, industry and regional levels. The set of models is designed to run in a recursive manner (see Figure 3). Global Insight's Macroeconomic Model determines the national economy's growth path and final demand mix. The Global Insight Macroeconomic Model provides projections of over 1300 concepts spanning final demands, aggregate supply, prices, incomes, international trade, industrial detail, interest rates and financial flows.

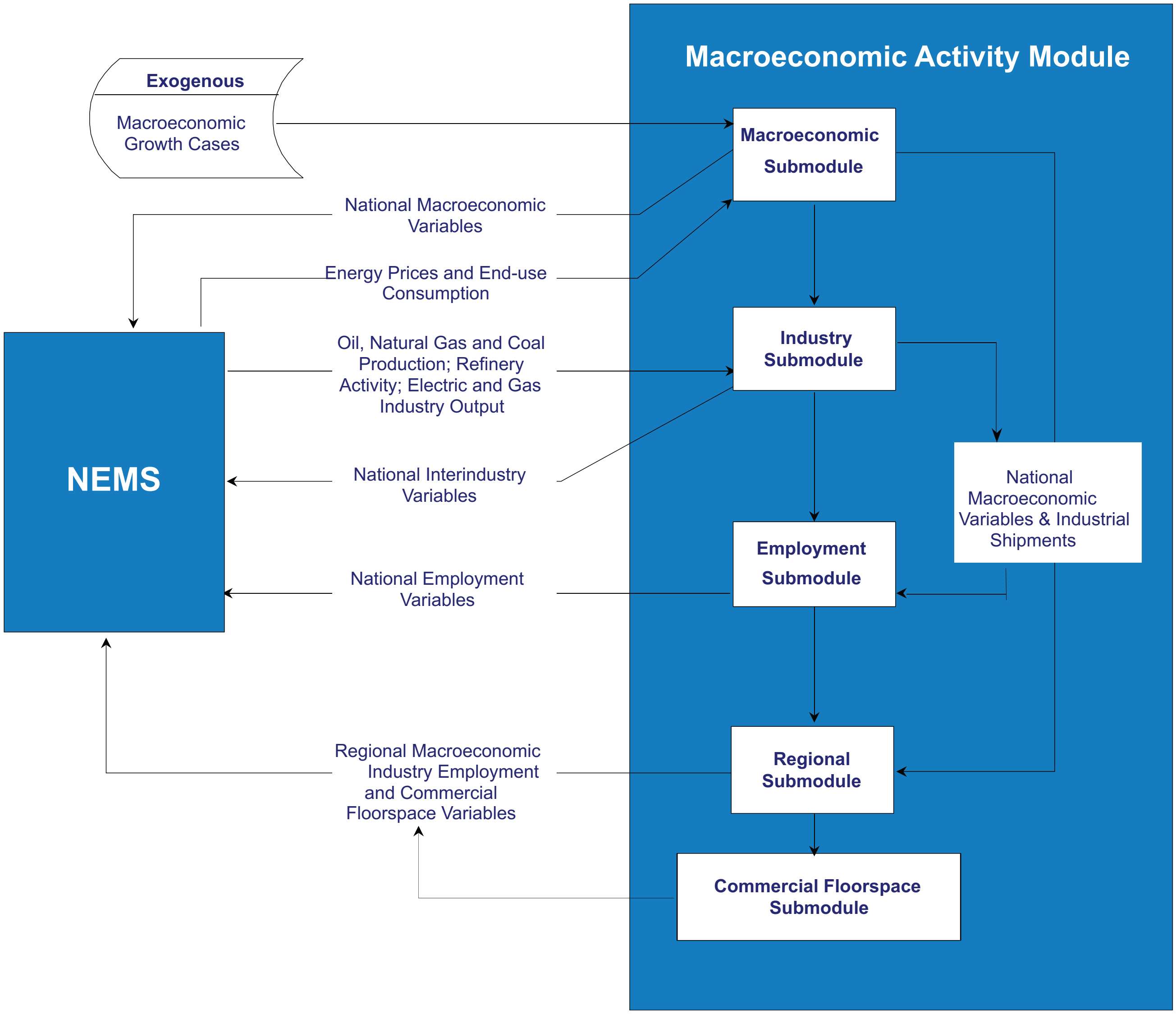
The Industry Submodule takes the final demand projections from the Macroeconomic Submodule as inputs to provide projections of output and other key indicators for 61 sectors, covering the entire economy. This is later aggregated to 41 sectors to provide information to NEMS. The Industry Submodule insures that supply by industry is consistent with the final demands (consumption, investment, government spending, exports and imports) generated in the Macroeconomic Submodule.

The Employment Submodule takes the industry output projections from the Industry Submodule and national wage rates, productivity trends and average work-week trends from the Macroeconomic Submodule to project employment for the 41 NEMS industries. The sum of non-agricultural employment is constrained to sum to the national total projected by the Macroeconomic Submodule.

The Regional Submodule determines the level of industry output and employment, population, incomes, and housing activity in each of nine Census regions. The Commercial Floorspace Submodule calculates regional floorspace for 13 types of building use by Census Division.

MAM Outputs	Inputs from NEMS	Exogenous Inputs
Gross domestic product Other economic activity measures, including housing starts, commercial floorspace growth, vehicle sales, population Price indices and deflators Production and employment for manufacturing Production and employment for nonmanufacturing Interest rates	Petroleum, natural gas, coal, and electricity prices Oil, natural gas, and coal production Electric and gas industry output Refinery output End-use energy consumption by fuel	Macroeconomic variables defining alternative economic growth cases

Figure 3. Macroeconomic Activity Module Structure



Integrated forecasts of NEMS center around estimating the state of the energy-economy system under a set of alternative energy conditions. Typically, the projections fall into the following four types of integrated NEMS simulations:

- Baseline Projection
- Alternative World Oil Prices
- Proposed Energy Fees or Emissions Permits
- Proposed Changes in Combined Average Fuel Economy (CAFE) Standards

In these integrated NEMS simulations, projection period baseline values for over 240 macroeconomic and demographic variables from MAM are passed to NEMS which solves for demand, supply and prices of energy for the projection period. These energy prices and quantities are passed back to MAM and solved in the Macroeconomic, Industry, Employment, Regional, and Commercial Floorspace Submodules in the EViews environment.[11]

11 Eviews is a model building nad operating software package maintained by QMS (Quantitative Micro Software.)

International Energy Module

International Energy Module

The International Energy Module (IEM) (Figure 4) performs the following functions:

- Calculates the world oil price (WOP) that equilibrates world crude-like liquids supply with demand for each year. The WOP is defined as the price of light, low sulfur crude oil delivered to Cushing, Oklahoma.
- Provides the projected world crude-like liquids supply curve (for each year) used by the Petroleum Market Module (PMM). These curves are adjusted to reflect expected conditions in international oil markets and projected changes in U.S. crude-like liquids production and consumption.
- Provide annual regional (country) level production detail for conventional and unconventional liquids based on exogenous assumptions about expected country-level liquid fuels production and producer behavior.
- Projects crude oil and light and heavy refined product import quantities into the U.S. by year and by source based on exogenous assumptions about future exploration, production, refining, and distribution investments worldwide.

Scope of IEM

Non-U.S. liquid fuels markets are represented in NEMS by the interaction between the PMM and the IEM. Using the specific algorithm described in the documentation of this module, IEM calculates the WOP that equilibrates world crude-like liquids supply with demand for each year. The IEM then estimates new world crude-like liquids supply curves based on exogenous, expected U.S. and world crude-like liquids supply and demand curves and that incorporate any changes in U.S. crude-like liquids production or consumption projected by other NEMS modules. Operationally, IEM passes to PMM an array of nine points of this supply curve, with the equilibrium point being the fifth point of this array.

Input data into IEM contain the historical percentages of imports of oils, heavy and light products imported into U.S. from different regions in the world. Using these values and total imports into the U.S. of crudes, heavy and light products provided by PMM, IEM generates a report, with imports by source for every year in the projection.

While the IEM is intended to be executed as a module of the NEMS system, and utilizing its complete capabilities and features requires a NEMS interface, it is also possible to execute the IEM module on a stand-alone basis. In stand-alone mode, the IEM calculates the WOP based on an exogenously specified projection of U.S. crude-like liquids production and consumption. Sensitivity analyses can be conducted to examine the response of the world oil market to changes in oil price, production capacity, and demand. To summarize, the model searches for the WOP that equilibrates crude-like liquids supply and demand at the world level.

Based on the final results for U.S. total liquids production and consumption, IEM also provides an International Petroleum Supply and Disposition Summary table for world conventional and unconventional liquids production as well as for world liquids demand by region. Exogenous data used to build this report is contained in omsinput.wk1 file. Each scenario has its own version of this file.

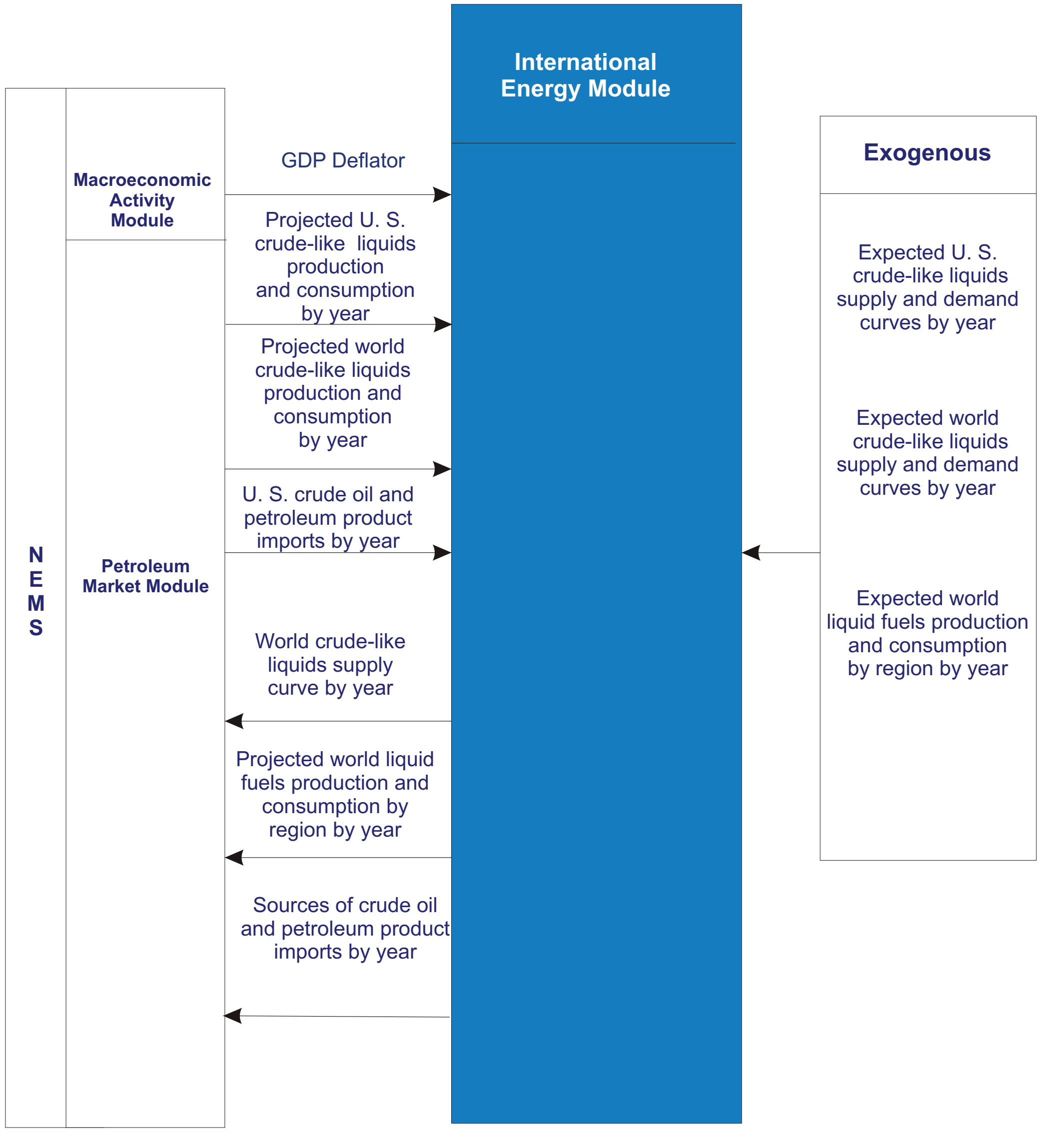
Because U.S. production and consumption of conventional liquids are dynamic values (output from NEMS), all other world regions have been proportionally updated such that the world liquids production and consumption reflect the corresponding value as in the *International Energy Outlook* (*IEO*).

Relation to Other NEMS Components

The IEM both uses information from and provides information to other NEMS components. It primarily uses information about projected U.S and world crude-like liquids production and consumption and petroleum imports and provides information about the world liquid fuels markets, including global crude-like liquids supply curves and the sources of petroleum imports into the U.S. It should be noted, however, that the present focus of the IEM is on the international oil market where the

IEM *Outputs*	Inputs from NEMS	Exogenous Inputs
World crude-like liquids supply curves Projected world liquid fuels production and consumption by region Sources of crude oil and petroleum product imports by year	Controlling information: iteration count, time horizon, etc GDP deflator Projected U.S. and world crude-like liquids production and consumption U.S. crude oil and petroleum product imports	Expected US and world crude-like liquids supply and demand curves Expected world liquid fuel production and consumption by region

Figure 4. International Energy Module Structure



WOP is computed. Any interactions between the U.S. and foreign regions in fuels other than oil (for example, coal trade) are modeled in the particular NEMS module that deals with that fuel.

For U.S. crude-like liquids production and consumption in any year of the projection period, the IEM uses projections generated by the NEMS PMM (based on supply curves provided by the Oil and Gas Supply Module (OGSM) and demand curves from the end-use demand modules).

U.S. and world expected crude-like liquids supply and demand curves, for any year in the projection period, are exogenously provided through data included in input file omsecon.txt, as detailed in the documentation of the IEM.

Residential Demand Module

Residential Demand Module

The residential demand module (RDM) projects energy consumption by Census division for seven marketed energy sources plus solar, wind, and geothermal energy. RDM is a structural model and its demand projections are built up from projections of the residential housing stock and energy-consuming equipment. The components of RDM and its interactions with the NEMS system are shown in Figure 5. NEMS provides projections of residential energy prices, population, disposable income, and housing starts, which are used by RDM to develop projections of energy consumption by end–use service, fuel type, and Census division.

RDM incorporates the effects of four broadly-defined determinants of energy consumption: economic and demographic effects, structural effects, technology turnover and advancement effects, and energy market effects. Economic and demographic effects include the number, dwelling type (single-family, multifamily or mobile homes), occupants per household, disposable income, and location of housing units.Structural effects include increasing average dwelling size and changes in the mix of desired end-use services provided by energy (new end uses and/or increasing penetration of current end uses, such as the increasing popularity of electronic equipment and computers). Technology effects include changes in the stock of installed equipment caused by normal turnover of old, worn out equipment with newer versions that tend to be more energy efficient, the integrated effects of equipment and building shell (insulation level) in new construction, and the projected availability of even more energy-efficient equipment in the future. Energy market effects include the short-run effects of energy prices on energy demands, the longer-run effects of energy prices on the efficiency of purchased equipment and the efficiency of building shells, and limitations on minimum levels of efficiency imposed by legislated efficiency standards.

Housing Stock Submodule

The base housing stock by Census division and dwelling type is derived from EIA's 2005 Residential Energy Consumption Survey (RECS). Each element of the of the base stock is retired on the basis of a constant rate of decay for each dwellling type. RDM receives as an input from the macroeconomic activity module projections of housing additions by type and Census division. RDM supplements the surviving stocks from the previous year with the projected additions by dwelling type and Census division. The average square footage of new construction is based on recent upward trends developed from the RECS and the Census Bureau's Characteristics of New Housing.

Appliance Stock Submodule

The installed stock of appliances is also taken from the 2005 RECS. The efficiency of the appliance stock is derived from historical shipments by efficiency level over a multi-year interval for the following equipment: heat pumps, gas furnaces, central air conditioners, room air conditioners, water heaters, refrigerators, freezers, stoves, dishwashers, clothes washers, and clothes dryers. A linear retirement function with both minimum and maximum equipment lives is used to retire equipment in surviving housing units. For equipment where shipment data are available, the efficiency of the retiring equipment varies over the projection. In early years, the retiring efficiency tends to be lower as the older, less efficient equipment in the stock turns over first. Also, as housing units retire, the associated appliances are removed from the base appliance stock as well. Additions to the base stock are tracked separately for housing units existing in 2005 and for cumulative new construction.

As appliances are removed from the stock, they are replaced by new appliances with generally higher efficiencies due to technology improvements, equipment standards, and market forces. Appliances added due to new construction are accumulated and retired parallel to appliances in the existing stock. Appliance stocks are maintained by fuel, end use, and technology as shown in Table 2.

Technology Choice Submodule

Fuel-specific equipment choices are made for both new construction and replacement purchases. For new construction, initial heating system shares (taken from the most recently available Census Bureau survey data covering new construction, currently 2005) are adjusted

RDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy demand by service and fuel type Changes in housing and appliance stocks Appliance stock efficiency	Energy product prices Housing starts Population	Current housing stocks and retirement rates Current appliance stocks and life expectancy New appliance types, efficiences, and costs Housing shell retrofit indices Unit energy consumption Square footage

Figure 5. Residential Demand Module Structure

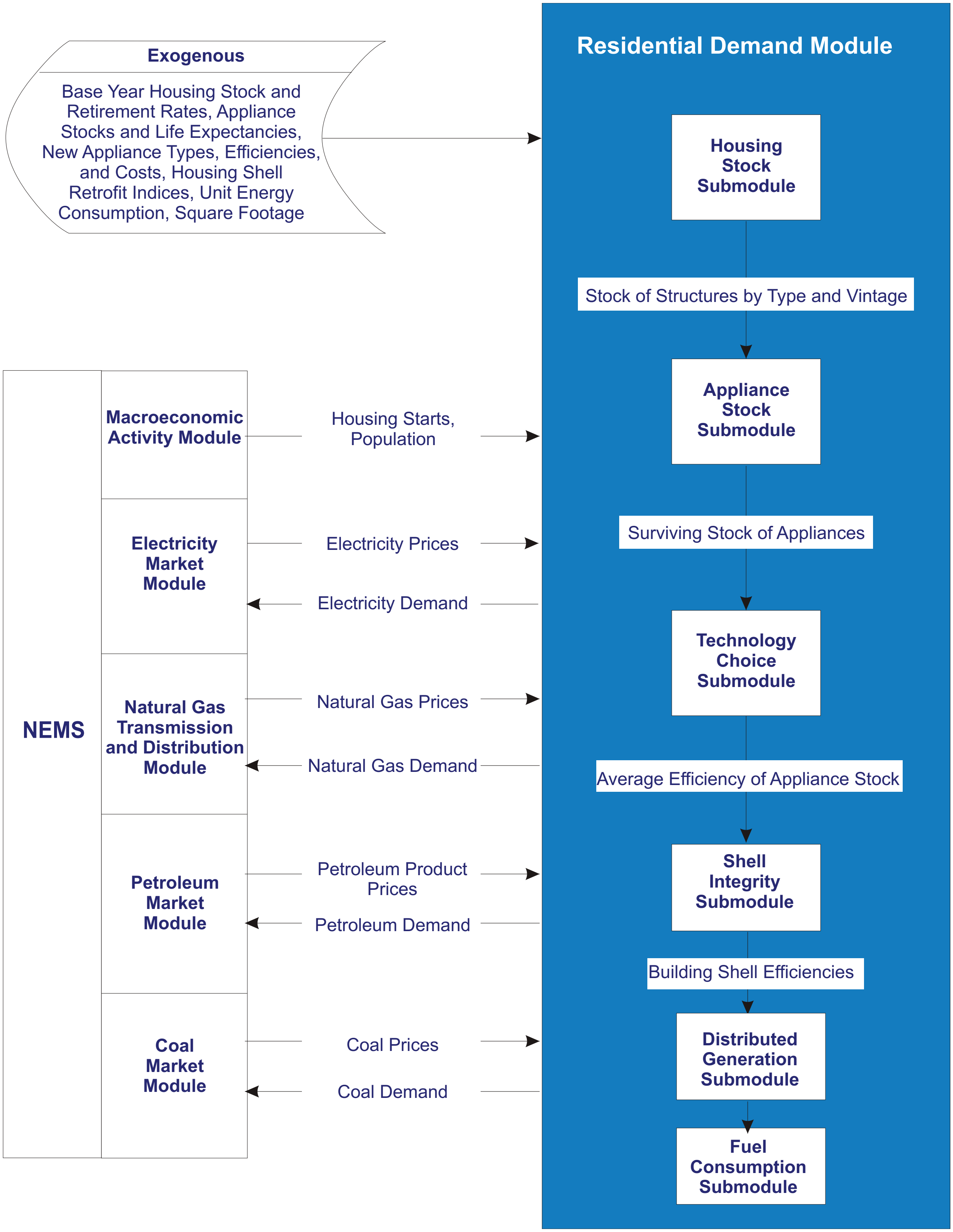


Table 2. NEMS Residential Module Equipment Summary

Space Heating Equipment: electric furnace, electric air-source heat pump, natural gas furnace, natural gas hydronic, kerosene furnace, liquefied petroleum gas, distillate furnace, distillate hydronic, wood stove, ground-source heat pump, natural gas heat pump.

Space Cooling Equipment: room air conditioner, central air conditioner, electric air-source heat pump, ground-source heat pump, natural gas heat pump.

Water Heaters: solar, natural gas, electric distiallate, liquefied petroleum gas.

Refrigerators: 18 cubic foot top-mounted freezer, 25 cubic foot side-by-side with through-the-door features.

Freezers: chest - manual defrost, upright - manual defrost.

Lighting: incandescent, compact fluorescent, LED, halogen, linear fluoresent.

Clothes Dryers: natural gas, electric.

Cooking: natural gas, electric, liquefied petroleum gas.

Dishwashers

Clothes Washers

Fuel Cells

Solar Photovoltaic

Wind

based on relative life cycle costs for all competing technology and fuel combinations. Once new home heating system shares are established, the fuel choices for other services, such as water heating and cooking, are determined based on the fuel chosen for space heating. For replacement purchases, fuel switching is allowed for an assumed percentage of all replacements but is dependent on the estimated costs of fuel-switching (for example, switching from electric to gas heating is assumed to involve the costs of running a new gas line).

For both replacement equipment and new construction, a “second-stage” of the equipment choice decision requires selecting from several available efficiency levels. The efficiency range of available equipment represents a “menu” of efficiency levels and installed cost combinations projected to be available at the time the choice is being made. Costs and efficiencies for selected appliances are shown in Table 3, derived from the report Assumptions to the *Annual Energy Outlook 2009*.[12] At the low end of the efficiency range are the minimum levels required by legislated standards. In any given year, higher efficiency levels are associated with higher installed costs. Thus, purchasing higher than the minimum efficiency involves a trade-off between higher installation costs and future savings in energy expenditures. In RDM, these trade-offs are calibrated to recent shipment, cost, and efficiency data. Changes in purchases by efficiency level are based on changes in either the installed capital costs or changes in the first-year operating costs across the available efficiency levels. As energy prices increase, the incentive of greater energy expenditures savings will promote increased purchases of higher-efficiency equipment. In some cases, due to government programs or general projections of technology improvement, increases in efficiency or decreases in the installed costs of higher-efficiency equipment will also promote purchases of higher-efficiency equipment.

Shell Integrity Submodule

Shell integrity is also tracked separately for the existing housing stock and new construction. Shell integrity for existing construction is assumed to respond to increases in real energy prices by becoming more efficient. There is no change in existing shell integrity when real energy prices decline. New shell efficiencies are based on the cost and performance of the heating and cooling equipment as well as the shell characteristics. Several efficiency levels of shell characteristics are available throughout the projection period and can change over time based on changes in building codes. All shell efficiencies are subject to a maximum shell efficiency based on studies of currently available residential construction methods.

Distributed Generation Submodule

Distributed generation equipment with explicit technology characterizations is also modeled for residential customers. Currently, three technologies are characterized, photovoltaics, wind, and fuel cells. The submodule incorporates historical estimates of photovoltaics (residential-sized fuel cells are not expected to be commercialized until after 2005, the base year of the model) from its technology characterization and exogenous penetration input file. Program-based photovoltaic

12 Energy Information Administration, Assumptions to the Annual Energy Outlook 2009, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2009).pdf (Washington, DC, March 2009).

estimates for the Department of Energy's Million Solar Roofs program are also input to the submodule from the exogenous penetration portion of the input file. Endogenous, economic purchases are based on a penetration function driven by a cash flow model that simulates the costs and benefits of distributed generation purchases. The cash flow calculations are developed from NEMS projected energy prices coupled with the technology characterizations provided from the input file.

Potential economic purchases are modeled by Census division and technology for all years subsequent to the base year. The cash flow model develops a 30-year cost-benefit horizon for each potential investment. It includes considerations of annual costs (down payments, loan payments, maintenance costs and, for fuel cells, gas costs) and annual benefits (interest tax deductions, any applicable tax credits, electricity cost savings, and water heating savings for fuel cells) over the entire 30-year period. Penetration for a potential investment in either photovoltaics, wind, or fuel cells is a function of whether it achieves a cumulative positive discounted cash flow, and if so, how many years it takes to achieve it.

Once the cumulative stock of distributed equipment is projected, reduced residential purchases of electricity are provided to NEMS. For fuel cells, increased residential natural gas consumption is also provided to NEMS based on the calculated energy input requirements of the fuel cells, partially offset by natural gas water heating savings from the use of waste heat from the fuel cell.

Energy Consumption Submodule

The fuel consumption submodule modifies base year energy consumption intensities in each projection year. Base year energy consumption for each end use is derived from energy intensity estimates from the 2005 RECS. The base year energy intensities are modified for the following effects: (1) increases in efficiency, based on a comparison of the appliance stock serving this end use relative to the base year stock, (2) changes in shell integrity for space heating and cooling end uses, (3) changes in real fuel prices—(short-run price elasticity effects), (4) changes in square footage, (5) changes in the number of occupants per household, (6) changes in disposable income, (7) changes in weather relative to the base year, (8) adjustments in utilization rates caused by efficiency increases (efficiency "rebound" effects), and (9) reductions in purchased electricity and increases in natural gas consumption from distributed generation. Once these modifications are made, total energy use is computed across end uses and housing types and then summed by fuel for each Census division.

Table 3. Characteristics of Selected Equipment

Equipment Type	Relative Performance[1]	2007 Installed Cost ($2007)[2]	Efficiency[3]	2020 Installed Cost ($2007)[2]	Efficiency[3]	Approximate Hurdle Rate
Electric Heat Pump	Minimum	$3,800	13.0	$3,800	13.0	15%
	Best	$6,700	17.0	$6,700	20.0	
Natural Gas Furnace	Minimum	$1,900	0.80	$1,900	0.80	15%
	Best	$3,050	0.96	$2,700	0.96	
Room Air Conditioner	Minimum	$310	9.8	$310	9.8	140%
	Best	$925	11.7	$875	12.0	
Central Air Conditioner	Minimum	$3,000	13.0	$3,000	13.0	15%
	Best	$5,700	21.0	$5,750	23.0	
Refrigerator (23.9 cubic ft in adjusted volume)	Minimum	$550	510	$550	510	19%
	Best	$950	417	$1000	417	
Electric Water Heater	Minimum	$400	0.90	$400	0.90	30%
	Best	$1,400	2.4	$1,700	2.4	

[1]Minimum performance refers to the lowest efficiency equipment available. Best refers to the highest efficiency equipment available.

[2]Installed costs are given in 2007 dollars in the original source document.

[3]Efficiency measurements vary by equipment type. Electric heat pumps and central air conditioners are rated for cooling performance using the Seasonal Energy Efficiency Ratio (SEER); natural gas furnaces are based on Annual Fuel Utilization Efficiency; room air conditioners are based on Energy Efficiency Ratio (EER); refrigerators are based on kilowatt-hours per year; and water heaters are based on Energy Factor (delivered Btu divided by input Btu).

Source: Navigant Consulting, *EIA Technology Forecast Updates-Residential and Commercial Buildings Technologies*, September 2007.

Commercial Demand Module

Commercial Demand Module

The commercial demand module (CDM) projects energy consumption by Census division for eight marketed energy sources plus solar, wind, and geothermal energy. For the three major commercial sector fuels, electricity, natural gas and distillate oil, CDM is a structural model and the projections are built up from the stock of commercial floorspace and energy-consuming equipment. For the remaining five marketed minor fuels, simple econometric projections are made.

The commercial sector encompasses business establishments that are not engaged in industrial or transportation activities. Commercial sector energy is consumed mainly in buildings, except for a relatively small amount for services such as street lights and water supply. CDM incorporates the effects of four broadly-defined determinants of energy consumption: economic and demographics, structural, technology turnover and change, and energy markets. Demographic effects include total floorspace, building type and location. Structural effects include changes in the mix of desired end-use services provided by energy (such as the penetration of telecommunications equipment, personal computers and other office equipment). Technology effects include changes in the stock of installed equipment caused by the normal turnover of old, worn out equipment to newer versions that tend to be more energy efficient, the integrated effects of equipment and building shell (insulation level) in new construction, and the projected availability of equipment with even greater energy-efficiency. Energy market effects include the short-run effects of energy prices on energy demands, the longer-run effects of energy prices on the efficiency of purchased equipment, and limitations on minimum levels of efficiency imposed by legislated efficiency standards. The model structure carries out a sequence of five basic steps, as shown in Figure 6. The first step is to project commercial sector floorspace. The second step is to project the energy services (space heating, lighting, etc.) required by the projected floorspace. The third step is to project the electricity generation and water and space heating supplied by distributed generation and combined heat and power (CHP) technologies. The fourth step is to select specific technologies (natural gas furnaces, fluorescent lights, etc.) to meet the demand for energy services. The last step is to determine how much energy will be consumed by the equipment chosen to meet the demand for energy services.

Floorspace Submodule

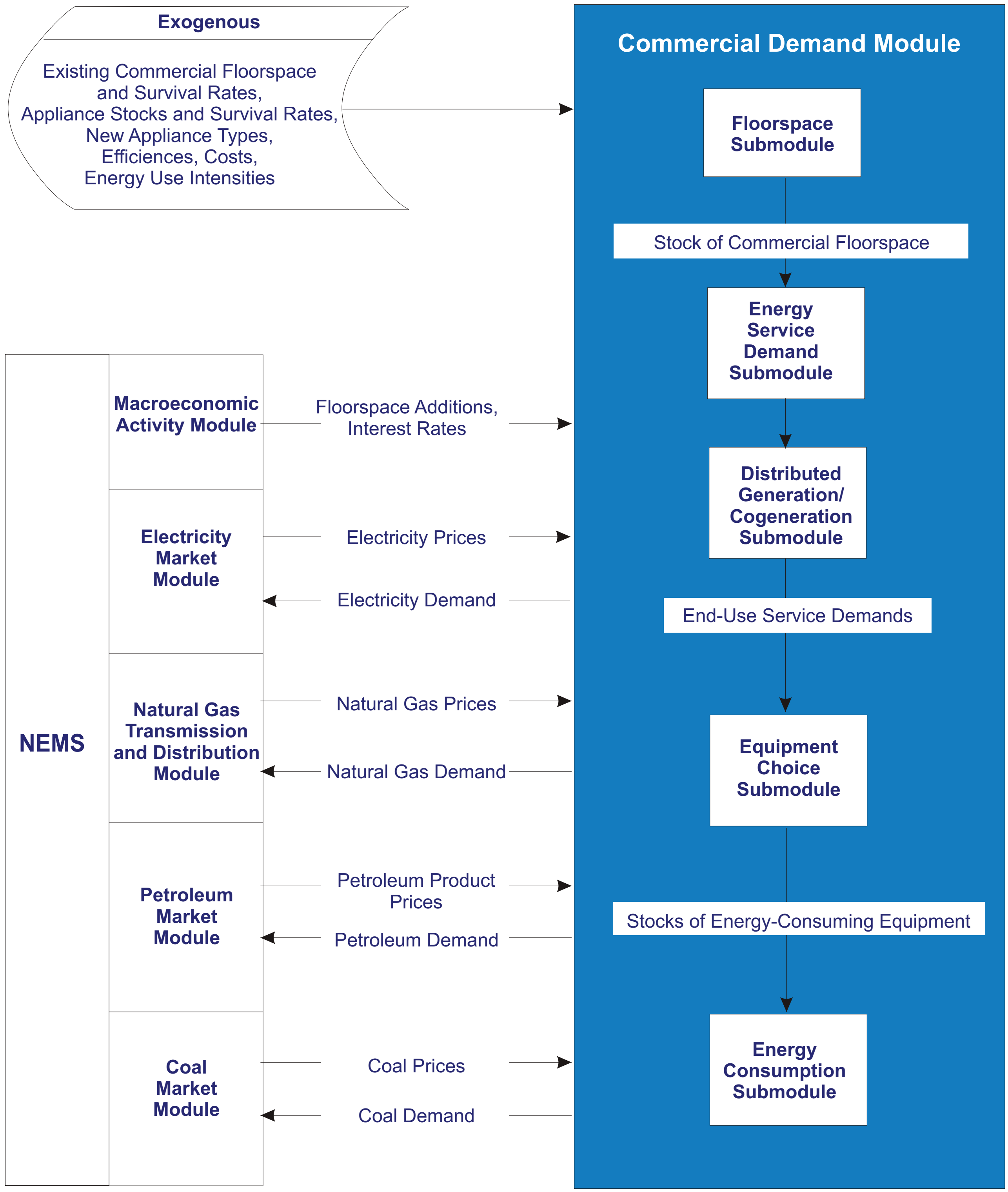
The base stock of commercial floorspace by Census division and building type is derived from EIA's 2003 Commercial Buildings Energy Consumption Survey (CBECS). CDM receives projections of total floorspace by building type and Census division from the macroeconomic activity module (MAM) based on IHS Global Insight, Inc. definitions of the commercial sector. These projections embody both economic and demographic effects on commercial floorspace. Since the definition of commercial floorspace from IHS Global Insight, Inc. is not calibrated to CBECS, CDM estimates the surviving floorspace from the previous year and then calibrates its new construction so that growth in total floorspace matches that from MAM by building type and Census division.

CDM models commercial floorspace for the following 11 building types:

- Assembly
- Education
- Food sales
- Food service
- Health care
- Lodging
- Office-large
- Office-small
- Mercantile and service
- Warehouse
- Other

CDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy demand by service and fuel type Changes in floorspace and appliance stocks	Energy product prices Interest rates Floorspace growth	Existing commercial floorspace Floorspace survival rates Appliance stocks and survival New appliance types, efficiencies, costs Energy use intensities

Figure 6. Commercial Demand Module Structure



Commercial Demand Module

Energy Service Demand Submodule

Energy consumption is derived from the demand for energy services. So the next step is to project energy service demands for the projected floorspace. CDM models service demands for the following ten end-use services:

- Heating
- Cooling
- Ventilation
- Water heating
- Lighting
- Cooking
- Refrigeration
- Office equipment personal computer
- Office equipment other
- Other end uses.

Different building types require unique combinations of energy services. A hospital must have more light than a warehouse. An office building in the Northeast requires more heating than one in the South. Total service demand for any service depends on the floorspace, type, and location of buildings. Base service demand by end use by building type and Census division is derived from estimates developed from CBECS energy consumption data. Projected service demands are adjusted for trends in new construction based on CBECS data concerning recent construction.

Distributed Generation and CHP Submodule

Commercial consumers may decide to purchase equipment to generate electricity (and perhaps provide heat as well) rather than depend on purchased electricity to fulfill all of their electric power requirements. The third step of the commercial module structure is to project electricity generation, fuel consumption, water heating, and space heating supplied by eleven distributed generation and CHP technologies. The technologies characterized include: photovoltaic solar systems, wind turbines, natural gas fuel cells, reciprocating engines, turbines and microturbines, diesel engine, coal-fired CHP, and municipal solid waste, wood, and hydroelectric generators.

Existing electricity generation by CHP technologies is derived from historical data contained in the most recent year's version of Form EIA-860, Annual Electric Generator Report. The estimated units form the installed base of CHP equipment that is carried forward into future years and supplemented with any additions. Proven installations of solar photovoltaic systems, wind turbines and fuel cells are also included based on information from the Departments of Energy and Defense. For years following the base year, an endogenous projection of distributed generation and CHP is developed based on the economic returns projected for distributed generation technologies. A detailed discounted cash-flow approach is used to estimate the internal rate of return for an investment. The calculations include the annual costs (down payments, loan payments, maintenance costs, and fuel costs) and returns (tax deductions, tax credits, and energy cost savings) from the investment covering a 30-year period from the time of the investment decision. Penetration of these technologies is a function of how quickly an investment in a technology is estimated to recoup its flow of costs. In terms of NEMS projections, investments in distributed generation reduce purchases of electricity. Fuel consuming technologies also generate waste heat that is assumed to be partially captured and used to offset commercial water heating and space heating energy use.

Equipment Choice Submodule

Once service demands are projected, the next step is to define the type and efficiency of equipment that will be used to satisfy the demands. The bulk of equipment required to meet service demand will carry over from the equipment stock of the previous model year. However, equipment must always be purchased to satisfy service demand for new construction. It must also be purchased to replace equipment that has either worn out (replacement equipment) or reached the end of its economically useful life (retrofit equipment). For required equipment replacements, CDM uses a constant decay rate based on equipment life. A technology will be retrofitted only if the combined annual operating and maintenance costs plus annualized capital costs of a potential technology are lower than the annual operating and maintenance costs of an existing technology.

Equipment choices are made based on a comparison of annualized capital and operating and maintenance costs across all allowable equipment for a particular end-use service. In order to add inertia to the equipment choices, only subsets of the total menu of potentially available equipment may be allowed for defined market segments. For example, only 7 percent of floorspace in large office buildings may consider all available equipment using any fuel or technology when making space heating equipment replacement decisions. A second segment equal to 31 percent of floorspace, must select from technologies using the same fuel as already installed. A third segment, the remaining 62 percent of floorspace, is constrained to consider only different efficiency levels of the same fuel and technology already installed. For lighting and refrigeration, all replacement choices are limited to the same technology class, where technologies are broadly defined to encompass the principal competing technologies for a particular application. For example, a commercial ice maker may replace another ice maker, but may not replace a refrigerated vending machine.

When computing annualized costs to determine equipment choices, commercial floorspace is segmented by what are referred to as hurdle rates or implicit discount rates (to distinguish them from the generally lower and more common notion of financial discount rates). Seven segments are used to simulate consumer behavior when purchasing commercial equipment. The segments range from rates as low as the 10-year Treasury bond rate to rates high enough to guarantee that only equipment with the lowest capital cost (and least efficiency) is chosen. As real energy prices increase (decrease) there is an incentive for all but the highest implicit discount rate segments to purchase increased (decreased) levels of efficiency.

The equipment choice submodule is designed to choose among a discrete set of technologies that are characterized by a menu which defines availability, capital costs, maintenance costs, efficiencies, and equipment life. Technology characteristics for selected space heating equipment are shown Table 4, derived from the report *Assumptions to the Annual Energy Outlook 2009.*[13] This menu of equipment includes technological innovation, market developments, and policy interventions. For the *AEO2009*, the technology types that are included for seven of the ten service demand categories are listed in Table 5.

The remaining three end-use services (PC-related office equipment, other office equipment, and other end uses) are considered minor services and are projected using exogenous equipment efficiency and market penetration trends.

Energy Consumption Submodule

Once the required equipment choices have been made, the total stock and efficiency of equipment for a particular end use are determined. Energy consumption by fuel can be calculated from the amount of service demand satisfied by each technology and the corresponding efficiency of the technology. At this stage, adjustments to energy consumption are also made. These include adjustments for changes in real energy prices (short-run price elasticity effects), adjustments in utilization rates caused by efficiency increases (efficiency rebound effects), and changes for weather relative to the CBECS survey year. Once these modifications are made, total energy use is computed across end uses and building types for the three major fuels, for each Census division. Combining these projections with the econometric/trend projections for the five minor fuels yields total projected commercial energy consumption.

13 Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2009).pdf (Washington, DC, March 2009)

Table 4. Capital Cost and Efficiency Ratings of Selected Commercial Space Heating Equipment[1]

Equipment Type	Vintage	Efficiency[2]	Capital Cost ($2007 per Mbtu/hour) [3]	Maintenance Cost ($2007 per Mbtu/hour) [3]	Service Life (Years)
Electric Rooftop Heat Pump	2007- typical	3.2	$72.78	$1.39	15
	2007- high efficiency	3.4	$96.67	$1.39	15
	2010 - typical (standard)	3.3	$76.67	$1.39	15
	2010 - high efficiency	3.4	$96.67	$1.39	15
	2020 - typical	3.3	$76.67	$1.39	15
	2020 - high efficiency	3.4	$96.67	$1.39	15
Ground-Source Heat Pump	2007 - typical	3.5	$140.00	$16.80	20
	2007 - high efficiency	4.9	$170.00	$16.80	20
	2010 - typical	3.5	$140.00	$16.80	20
	2010 - high efficiency	4.9	$170.00	$16.80	20
	2020 - typical	4.0	$140.00	$16.80	20
	2020 - high efficiency	4.9	$170.00	$16.80	20
Electric Boiler	Current typical	0.98	$17.53	$0.58	21
Packaged Electric	Typical	0.96	$16.87	$3.95	18
Natural Gas Furnace	Current Standard	0.80	$9.35	$0.97	20
	2007 - high efficiency	0.82	$9.90	$0.94	20
	2020 - typical	0.81	$9.23	$0.96	20
	2020 - high efficiency	0.90	$11.57	$0.86	20
	2030 - typical	0.82	$9.12	$0.94	20
	2030 - high efficiency	0.91	$11.44	$0.85	20
Natural Gas Boiler	Current Standard	0.80	$22.42	$0.50	25
	2007 - mid efficiency	0.85	$25.57	$0.47	25
	2007 - high efficiency	0.96	$39.96	$0.52	25
	2020 - typical	0.82	$21.84	$0.49	25
Natural Gas Heat Pump	2007 - absorption	1.4	$158.33	$2.50	15
	2010 - absorption	1.4	$158.33	$2.50	15
	2020 - absorption	1.4	$158.33	$2.50	15
Distillate Oil Furnace	Current Standard	0.81	$11.14	$0.96	20
	2020 - typical	0.81	$11.14	$0.96	20
Distillate Oil Boiler	Current Standard	0.83	$17.63	$0.15	20
	2007 - high efficiency	0.89	$19.84	$0.14	20
	2020 - typical	0.83	$17.63	$015	20

[1]Equipment listed is for the New England Census division, but is also representative of the technology data for the rest of the U.S. See the source referenced below for the complete set of technology data.·

[2]Efficiency measurements vary by equipment type. Electric rooftop air-source heat pumps, ground source and natural gas heat pumps are rated for heating performance using coefficient of performance; natural gas and distillate furnaces are based on Thermal Efficiency; and boilers are based on combustion efficiency.

[3]Capital and maintenance costs are given in 2007 dollars.

Source: Energy Information Administration, "EIA - Technology Forecast Updates - Residential and Commercial Building Technologies - Reference Case Second Edition (Revised)", Navigant Consulting, Inc., Reference Number 20070831.1, September 2007.

Table 5. Commercial End-Use Technology Types

End-Use Service by Fuel	Technology Types
Electric Space Heating	air-source heat pump, ground-source heat pump, boiler, packaged space heating
Natural Gas Space Heating	boiler, furnace, absorption heat pump
Fuel Oil Space Heating	boiler, furnace
Electric Space Cooling	air-source heat pump, ground-source heat pump, reciprocating chiller, centrifugal chiller, screw chiller, scroll chiller, rooftop air conditioner, residential style central air conditioner, window unit
Natural Gas Space Cooling	absorption chiller, engine-driven chiller, rooftop air conditioner, engine-driven heat pump, absorption heat pump
Electric Water Heating	electric resistance, heat pump water heater, solar water heater with electric back-up
Natural Gas Water Heating	natural gas water heater
Fuel Oil Water Heating	fuel oil water heater
Ventilation	constant air volume (CAV) system, variable air volume (VAV) system
Electric Cooking	range/oven/griddle, induction range/oven/griddle
Natural Gas Cooking	range/oven/griddle, power burner range/oven/griddle
Incandescent Style Lighting	incandescent, compact fluorescent, halogen, halogen-infrared, light emitting diode (LED)
Four-foot Fluorescent Lighting	magnetic ballast, electronic ballast-T8 electronic w/controls, electronic w/reflectors, electronic ballast-T5, electronic ballast-super T8, LED,
Eight-foot Fluorescent Lighting	magnetic ballast, electronic ballast, electronic-high output, LED
High Intensity-Discharge Lighting	metal halide, mercury vapor, high pressure sodium, electronic-T8 high output, electronic-T5 high output, LED
Refrigeration	supermarket compressor rack, suupermarket condenser, supermarket display case, walk-in cooler, walk-in freezer, reach-in refrigerator, reach-in freezer, ice machine, beverage merchandiser, refrigerated vending machine

Industrial Demand Module

Industrial Demand Module

The Industrial Demand Module (IDM) projects energy consumption for fuels and feedstocks for fifteen manufacturing industries and six nonmanufacturing industries, subject to delivered prices of energy and macroeconomic variables representing the value of shipments for each industry. The module includes electricity generated through Combined Heat and Power (CHP) systems that is either used in the industrial sector or sold to the electricity grid. The IDM structure is shown in Figure 7.

Industrial energy demand is projected as a combination of “bottom up” characterizations of the energy-using technology and “top down” econometric estimates of behavior. The influence of energy prices on industrial energy consumption is modeled in terms of the efficiency of use of existing capital, the efficiency of new capital acquisitions, and the mix of fuels utilized, given existing capital stocks. Energy conservation from technological change is represented over time by trend-based “technology possibility curves.” These curves represent the aggregate efficiency of all new technologies that are likely to penetrate the future markets as well as the aggregate improvement in efficiency of 2002 technology.

IDM incorporates three major industry categories: energy-intensive manufacturing industries, non-energy-intensive manufacturing industries, and nonmanufacturing industries (see Table 6). The level and type of modeling and detail is different for each. Manufacturing disaggregation is at the 3-digit North American Industrial Classification System (NAICS) level, with some further disaggregation of large and energy-intensive industries. Detailed industries include food, paper, chemicals, glass, cement, steel, and aluminum. Energy product demands are calculated independently for each industry.

Each industry is modeled (where appropriate) as three interrelated components: buildings (BLD), boilers/steam/cogeneration (BSC), and process/assembly (PA) activities. Buildings are estimated to account for 4 percent of energy consumption in manufacturing industries (in nonmanufacturing industries, building energy consumption is not currently calculated).

Table 6. Economic Subsectors Within the IDM

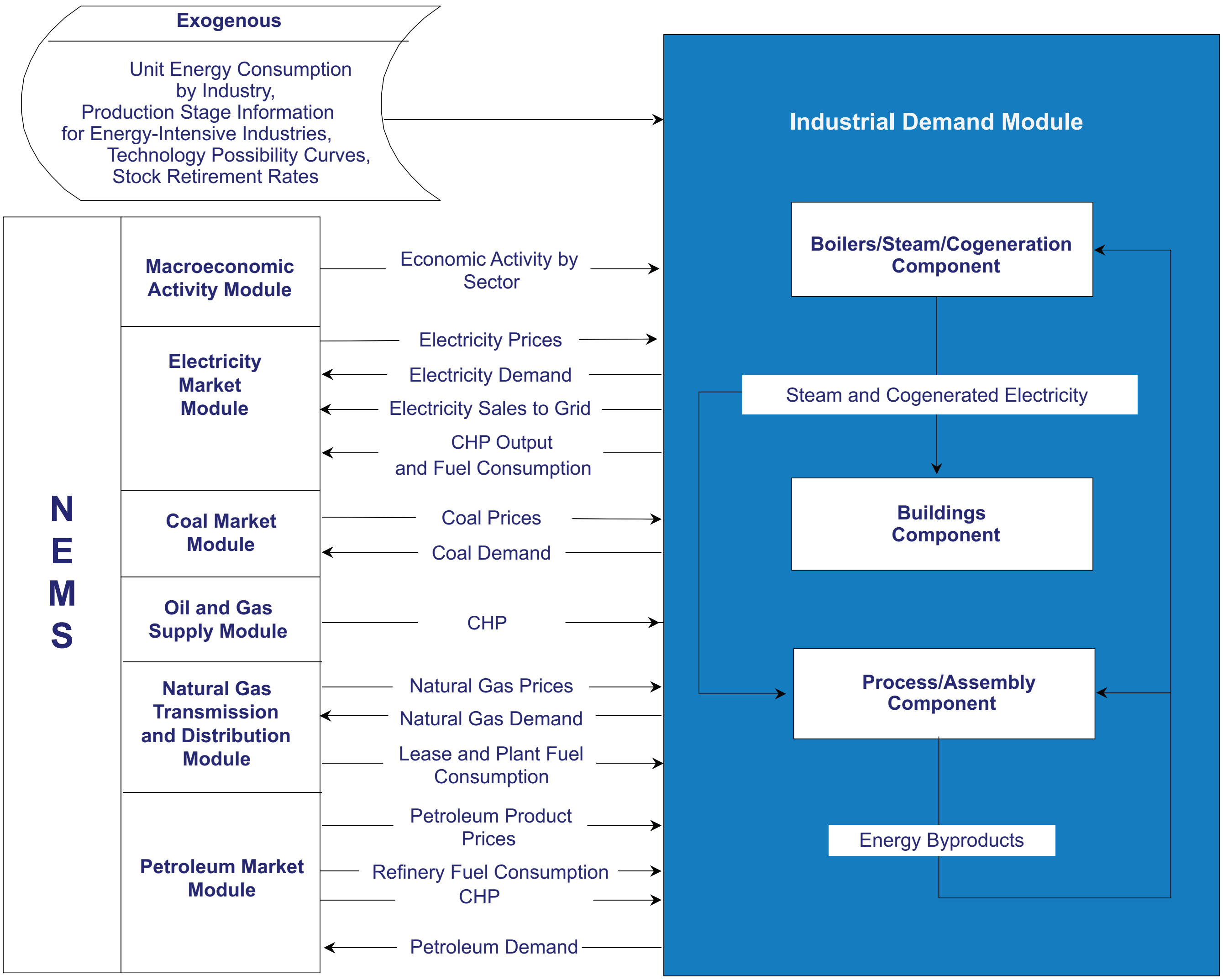
Energy-Intensive Manufacturing	**Nonmanufacturing Industries**
Food and Kindred Products (NAICS 311)	Agricultural Production - Crops (NAICS 111)
Paper and Allied Products (NAICS 322)	Other Agriculture including Livestock (NAICS 112-115)
Bulk Chemicals (NAICS 325)	Coal Mining (NAICS 2121)
Glass and Glass Products (NAICS 3272)	Oil and Gas Extraction (NAICS 211)
Hydraulic Cement (NAICS 32731)	Metal and Other Nonmetallic Mining (NAICS 2122-2123)
Blast Furnaces and Basic Steel (NAICS 331111)	Construction (NAICS 233-235)
Aluminum (NAICS 3313)	
Nonenergy-Intensive Manufacturing	
Metals-Based Durables (NAICS 332-336)	
Other Manufacturing (all remaining manufacturing NAICS)	

NAICS = North American Industry Classification System

Consequently, IDM uses a simple modeling approach for the BLD component. Energy consumption in industrial buildings is assumed to grow at the same rate as the average growth rate of employment and output in that industry. The BSC component consumes energy to meet the steam demands from and provide internally generated electricity to the other two components. The boiler component consumes by-product fuels and fossil fuels to produce steam, which is passed to the PA and BLD components.

IDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy demand by service and fuel type Electricity sales to grid Cogeneration output and fuel consumption	Energy product prices Economic output by industry Refinery fuel consumption Lease and plant fuel consumption Cogeneration from refineries and oil and gas production	Production stages in energy-intensive industries Technology possibility curves Unit energy consumption of outputs Capital stock retirement rates

Figure 7. Industrial Demand Module Structure



IDM models "traditional" CHP based on steam demand from the BLD and the PA components. The "non-traditional" CHP units are represented in the electricity market module since these units are mainly grid-serving, electricity-price-driven entities.

CHP capacity, generation, and fuel use are calculated from exogenous data on existing and planned capacity additions and new additions determined from an engineering and economic evaluation. Existing CHP capacity and planned additions are derived from Form EIA-860, "Annual Electric Generator Report," formerly Form EIA-867, "Annual Nonutility Power Producer Report." Existing CHP capacity is assumed to remain in service throughout the projection or, equivalently, to be refurbished or replaced with similar units of equal capacity.

Calculation of unplanned CHP capacity additions begins in 2009. Modeling of unplanned capacity additions is done in two parts: biomass-fueled and fossil-fueled. Biomass CHP capacity is assumed to be added to the extent possible as additional biomass waste products are produced, primarily in the pulp and paper industry. The amount of biomass CHP capacity added is equal to the quantity of new biomass available (in Btu), divided by the total heat rate from biomass steam turbine CHP.

Table 7. Fuel-Consuming Activities for the Energy-Intensive Manufacturing Subsectors

End Use Characterization
Food: direct fuel, hot water/steam, refrigeration, and other energy uses.
Bulk Chemicals: direct fuel, hot water/steam, electrotytic, and other energy uses.
Process Step characterization
Pulp and Paper: wood preparation, waste pulping, mechanical pulping, semi-chemical pulping, kraft pulping, bleaching, and paper making.
Glass: batch preparation, melting/refining, and forming.
Cement: dry process clinker, wet process clinker, and finish grinding.
Steel: coke oven, open hearth steel making, basic oxygen furnace steel making, electric arc furnace steel making, ingot casting, continuous casting, hot rolling, and cold rolling.
Aluminum: primary and secondary (scrap) aluminum smelting, semi-fabrication (e.g. sheet, wire, etc.).

It is assumed that the technical potential for fossil-fuel source CHP is based primarily on supplying thermal requirements. First, the model assesses the amount of capacity that could be added to generate the industrial steam requirements not met by existing CHP. The second step is an economic evaluation of gas turbine prototypes for each steam load segment. Finally, CHP additions are projected based on a range of acceptable payback periods.

The PA component accounts for the largest share of direct energy consumption for heat and power, 55 percent. For the seven most energy-intensive industries, process steps or end uses are modeled using engineering concepts. The production process is decomposed into the major steps, and the energy relationships among the steps are specified.

The energy intensities of the process steps or end uses vary over time, both for existing technology and for technologies expected to be adopted in the future. In IDM, this variation is based on engineering judgement and is reflected in the parameters of technology possibility curves, which show the declining energy intensity of existing and new capital relative to the 2002 stock.

IDM uses "technology bundles" to characterize technological change in the energy-intensive industries. These bundles are defined for each production process step for five of the industries and for end uses in the remaining two energy-intensive industries. The process step industries are pulp and paper, glass, cement, steel, and aluminum. The end-use industries are food and bulk chemicals (see Table 7).

Machine drive electricity consumption in the food, bulk chemicals, metal-based durables, and balance of manufacturing sectors is calculated by a motor stock model. The beginning stock of motors is modified over the projection horizon as motors are added to accommodate growth in shipments for each sector, as motors are retired and replaced, and as failed motors are rewound. When a new motor is added, either to accommodate growth or as a replacement, an economic choice is made between purchasing a motor that meets the EPACT minimum for efficiency or a premium efficiency motor. There are seven motor size groups in each of the four industries. The EPACT efficiency standards only apply to the five smallest groups (up to 200 horsepower). As the motor stock changes over the projection horizon, the overall efficiency of the motor population changes as well.

The Unit Energy Consumption (UEC) is defined as the energy use per ton of throughput at a process step or as energy use per dollar of shipments for the end-use industries. The "Existing UEC" is the current average installed intensity as of 2002. The "New 2002 UEC" is the intensity assumed to prevail for a new installation in 2002. Similarly, the "New 2030 UEC" is the intensity expected to prevail for a new installation in 2030. For intervening years, the intensity is interpolated.

The rate at which the average intensity declines is determined by the rate and timing of new additions to capacity. In IDM, the rate and timing of new additions are functions of retirement rates and industry growth rates.

IDM uses a vintaged capital stock accounting framework that models energy use in new additions to the stock and in the existing stock. This capital stock is represented as the aggregate vintage of all plants built within an industry and does not imply the inclusion of specific technologies or capital equipment.

The capital stock is grouped into three vintages: old, middle, and new. The old vintage consists of capital in production prior to 2002, which is assumed to retire at a fixed rate each year. Middle-vintage capital is that added after 2002. New production capacity is built in the projection years when the capacity of the existing stock of capital in

IDM cannot produce the output projected by the NEMS regional submodule of the macroeconomic activity module. Capital additions during the projection horizon are retired in subsequent years at the same rate as the pre-2002 capital stock.

The energy-intensive and/or large energy-consuming industries are modeled with a structure that explicitly describes the major process flows or “stages of production” in the industry (some industries have major consuming uses).

Technology penetration at the level of major processes in each industry is based on a technology penetration curve relationship. A second relationship can provide additional energy conservation resulting from increases in relative energy prices. Major process choices (where applicable) are determined by industry production, specific process flows, and exogenous assumptions.

Recycling, waste products, and byproduct consumption are modeled using parameters based on off-line analysis and assumptions about the manufacturing processes or technologies applied within industry. These analyses and assumptions are mainly based upon environmental regulations such as government requirements about the share of recycled paper used in offices. IDM also accounts for trends within industry toward the production of more specialized products such as specialized steel which can be produced using scrap material versus raw iron ore.

Transportation Demand Module

Transportation Demand Module

The transportation demand module (TRAN) projects the consumption of transportation sector fuels by transportation mode, including the use of renewables and alternative fuels, subject to delivered prices of energy and macroeconomic variables, including disposable personal income, gross domestic product, level of imports and exports, industrial output, new car and light truck sales, and population. The structure of the module is shown in Figure 8.

Projections of future fuel prices influence fuel efficiency, vehicle-miles traveled, and alternative-fuel vehicle (AFV) market penetration for the current fleet of vehicles. Alternative-fuel vehicle shares are projected on the basis of a multinomial logit model, subject to State and Federal government mandates for minimum AFV sales volumes.

Fuel Economy Submodule

This submodule projects new light-duty vehicle fuel economy by 12 U.S. Environmental Protection Agency (EPA) vehicle size classes and 16 propulsion technologies (gasoline, diesel, and 14 AFV technologies) as a function of energy prices and income-related variables. There are 61 fuel-saving technologies which vary in cost and marginal fuel savings by size class. Characteristics of a sample of these technologies are shown in Table 8, a complete list is published in Assumptions to the Annual Energy Outlook 2009.[14] Technologies penetrate the market based on a cost-effectiveness algorithm that compares the technology cost to the discounted stream of fuel savings and the value of performance to the consumer. In general, higher fuel prices lead to higher fuel efficiency estimates within each size class, a shift to a more fuel-efficient size class mix, and an increase in the rate at which alternative-fuel vehicles enter the marketplace.

Regional Sales Submodule

Vehicle sales from the MAM are divided into car and light truck sales. The remainder of the submodule is a simple accounting mechanism that uses endogenous estimates of new car and light truck sales and the historical regional vehicle sales adjusted for regional population trends to produce estimates of regional sales, which are subsequently passed to the alternative-fuel vehicle and the light-duty vehicle stock submodules.

Alternative-Fuel Vehicle Submodule

This submodule projects the sales shares of alternative-fuel technologies as a function of technology attributes, costs, and fuel prices. The alternative-fuel vehicles attributes are shown in Table 9, derived from *Assumptions to the Annual Energy Outlook 2009*. Both conventional and new technology vehicles are considered. The alternative-fuel vehicle submodule receives regional new car and light truck sales by size class from the regional sales submodule.

The projection of vehicle sales by technology utilizes a nested multinomial logit (NMNL) model that predicts sales shares based on relevant vehicle and fuel attributes. The nesting structure first predicts the probability of fuel choice for multi-fuel vechicles within a technology set. The second level nesting predicts penetration among similar technologies within a technology set (i.e. gasoline versus diesel hybrids). The third level choice determines market share among the the different technology sets.[15]

TRAN Outputs	Inputs from NEMS	Exogenous Inputs
Fuel demand by mode Sales, stocks, and characteristics of vehicle types by size class Vehicle-miles traveled Fuel economy by technology type Alternative-fuel vehicle sales by technology type Light-duty commercial fleet vehicle characteristics	Energy product prices Gross domestic product Disposable personal income Industrial output Vehicle sales International trade Natural gas pipeline Population	Existing vehicle stocks by vintage and fuel economy Vehicle survival rates New vehicle technology characteristics Fuel availability Commercial availability Vehicle safety and emissions reglations Vehicle miles-per-gallon degradation rates

14 Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009* http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2009) (Washington, DC, January 2009).

15 Greene, David L. and S.M. Chin, "Alternative Fuels and Vehicles (AFV) Model Changes," Center for Transportation Analysis, Oak Ridge National Laboratory, page 1, (Oak Ridge, TN, November 14, 2000).

Table 8. Selected Technology Characteristics for Automobiles

	Fractional Fuel Efficiency Change	First Year Introduced	Fractional Horsepower Change
Material Substitution IV	0.099	2006	0
Drag Reduction IV	0.042	2000	0
5-Speed Automatic	0.025	1995	0
CVT	0.052	1998	0
Automated Manual Trans	0.073	2004	0
VVL-6 Clinder	0.033	2000	0.10
Camless Valve Actuation 6 Cylinder	0.058	2020	0.13
Electric Power Steering	0.015	2004	0
42V-Launch Assist and Regen	0.075	2005	-0.05

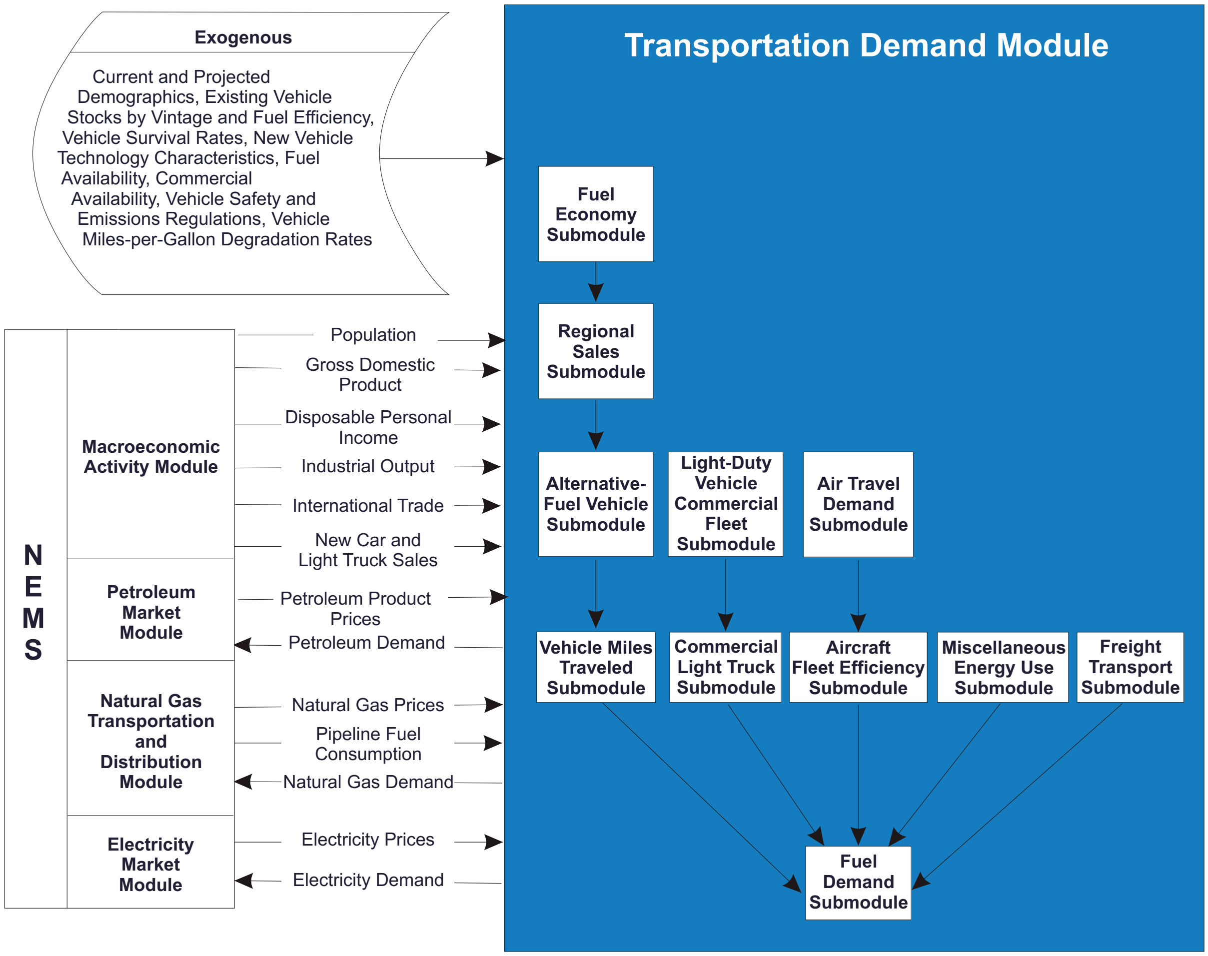
Table 9. Examples of Midsize Automobile Attributes

	Year	Gasoline	TDI Diesel	Ethanol Flex	LPG Bi-Fuel	Electric Gasoline Hybrid	Fuel Cell Hydrogen
Vehicle Price (thousand 2007 dollars)	2006	28.0	29.8	28.7	33.3	31.1	78.6*
	2030	29.8	30.7	30.2	35.0	31.0	54.2
Vehicle Miles per Gallon	2006	29.5	39.8	29.9	29.6	42.7	53.3*
	2030	37.8	48.2	38.1	37.7	51.0	54.9
Vehicle Range (miles)	2006	521	704	381	417	652	594*
	2030	674	910	492	539	843	674

*First year of availability

Transportation Demand Module

Figure 8. Transportation Demand Module Structure



Alternative Fuel Vehicles

Ethanol flex-fueled
Ethanol neat (85 percent ethanol)
Compressed natural gas (CNG)
CNG bi-fuel
Liquefied petroleum gas (LPG)
LPG bi-fuel
Battery electric vehicle
Plug-in hybrid with 10 mile all electric range
Plug-in hybrid with 40 mile all electric range
Gasoline hybrid
Diesel Hybrid
Fuel cell gasoline
Fuel cell hydrogen
Fuel cell methanol

The technology sets include:

- Conventional fuel capable (gasoline, diesel, bi-fuel and flex-fuel),
- Hybrid (gasoline and diesel) and plug-in hybrid
- Dedicated alternative fuel (compressed natural gas (CNG), liquified petroleum gas (LPG), and ethanol),
- Fuel cell (gasoline, methanol, and hydrogen),
- Electric battery powered (nickel-metal hydride, lithium)

The vehicles attributes considered in the choice algorithm include: price, maintenance cost, battery replacement cost, range, multi-fuel capability, home refueling capability, fuel economy, acceleration and luggage space.

With the exception of maintenance cost, battery replacement cost, and luggage space, vehicle attributes are determined endogenously.[16] The fuel attributes used in market share estimation include availability and price. Vehicle attributes vary by six EPA size classes for cars and light trucks and fuel availability varies by Census division. The NMNL model coefficients were developed to reflect purchase preferences for cars and light trucks separately.

Light-Duty Vehicle (LDV) Stock Submodule

This submodule specifies the inventory of LDVs from year to year. Survival rates are applied to each vintage, and new vehicle sales are introduced into the vehicle stock through an accounting framework. The fleet of vehicles and their fuel efficiency characteristics are important to the translation of transportation services demand into fuel demand.

TRAN maintains a level of detail that includes twenty vintage classifications and six passenger car and six light truck size classes corresponding to EPA interior volume classifications for all vehicles less than 8,500 pounds, as follows:

Light Duty Vehicle Size Classes

Cars:
- Mini-compact - less than 85 cubic feet
- Subcompact - between 85 and 99 cubic feet
- Compact - between 100 and 109 cubic feet
- Mid-size - between 110 and 119 cubic feet
- Large - 120 or more cubic feet
- Two-seater - designed to seat two adults

Trucks:
- Small vans - gross vehicle weight rating (GVWR) less than 4,750 pounds
- Large vans - GVWR 4,750 to 8,500 pounds
- Small pickups - GVWR less than 4,750 pounds
- Large pickups - GVWR 4,750 to 8,500 pounds
- Small utility - GVWR less than 4,750 pounds
- Large utility - GVWR 4,750 to 8,500 pounds

Vehicle-Miles Traveled (VMT) Submodule

This submodule projects travel demand for automobiles and light trucks. VMT per capita estimates are based on the fuel cost of driving per mile and per capita disposable personal income. Total VMT is calculated by multiplying VMT by the number of licensed drivers.

LDV Commercial Fleet Submodule

This submodule generates estimates of the stock of cars and trucks used in business, government, and utility fleets. It also estimates travel demand, fuel efficiency, and energy consumption for the fleet vehicles prior to their transition to the private sector at predetermined vintages.

Commercial Light Truck Submodule

The commercial light truck submodule estimates sales, stocks, fuel efficiencies, travel, and fuel demand for all trucks greater than 8,500 pounds and less than 10,000 pounds gross vehicle weight rating.

Air Travel Demand Submodule

This submodule estimates the demand for both passenger and freight air travel. Passenger travel is projected by domestic travel (within the U.S.), international travel (between U.S. and Non U.S.), and Non U.S. travel. Dedicated air freight travel is estimated for U.S. and Non U.S. demand. In each of the market segments, the demand for air travel is estimated as a function of the cost of air travel (including fuel costs) and economic growth (GDP, disposable income, and merchandise exports).

Aircraft Fleet Efficiency Submodule

This submodule projects the total world-wide stock and the average fleet efficiency of narrow body, wide body, and regional jets required to meet the projected travel demand. The stock estimation is based on the growth of travel demand and the flow of aircraft into and out of the United States The overall fleet efficiency is determined by the weighted average of the surviving aircraft efficiency (including retrofits) and the efficiencies of the newly acquired aircraft. Efficiency improvements of new aircraft are determined by projecting the market penetration of advanced aircraft technologies.

16 Energy and Environmental Analysis, Inc., Updates to the Fuel Economy Model (FEM) and Advanced Technology Vehicle (ATV:) Module of the National Energy Modeling System (NEMS) Transportation Model, prepared for the Energy Information Administration (EIA),

Freight Transport Submodule

This submodule translates NEMS estimates of industrial production into ton-miles traveled for rail and ships and into vehicle vehicle-miles traveled for trucks, then into fuel demand by mode of freight travel. The freight truck stock is subdivided into medium and heavy-duty trucks. VMT freight estimates by truck size class and technology are based on matching freight needs, as measured by the growth in industrial output by NAICS code, to VMT levels associated with truck stocks and new vehicles. Rail and shipping ton-miles traveled are also estimated as a function of growth in industrial output.

Freight truck fuel efficiency growth rates are tied to historical growth rates by size class and are also dependent on the maximum penetration, introduction year, fuel trigger price (based on cost-effectiveness), and fuel economy improvement of advanced technologies, which include alternative-fuel technologies. A subset of the technology characteristics are shown in Table 10. In the rail and shipping modes, energy efficiency estimates are structured to evaluate the potential of both technology trends and efficiency improvements related to energy prices.

Miscellaneous Energy Use Submodule

This submodule projects the use of energy in military operations, mass transit vehicles, recreational boats, and lubricants, based on endogenous variables within NEMS (e.g., vehicle fuel efficiencies) and exogenous variables (e.g., the military budget).

Table 10. Example of Truck Technology Characteristics (Diesel)

	Fuel Economy Improvement (percent)		Maximum Penetration (percent)		Introduction Year		Capital Cost (2001 dollars)	
	Medium	Heavy	Medium	Heavy	Medium	Heavy	Medium	Heavy
Aero Dynamics: bumper, underside air battles, wheel well covers	3.6	2.3	50	40	2002	N/A	N/A	$1,500
Low rolling resistence tires	2.3	2.7	50	66	2004	2005	$180	$550
Transmission: lock-up, electronic controls, reduced friction	1.8	1.8	100	100	2005	2005	$750	$1,000
Diesel Engine: hybrid electric powertrain	36.0	N/A	15	N/A	2010	N/A	$6,000	N/A
Reduce waste heat, thermal mgmt	N/A	9.0	N/A	35	N/A	2010	N/A	$2,000
Weight reduction	4.5	9.0	20	30	2010	2005	$1,300	$2,000
Diesel Emission No_x non-thermal plasma catalyst	-1.5	-1.5	25	25	2007	2007	$1,000	$1,250
PM catalytic filter	-2.5	-1.5	95	95	2008	2006	$1,000	$1,500
HC/CO: oxidation catalyst	-0.5	-0.5	95	95	2002	2002	$150	$250
NO_x adsorbers	-3.0	-3.0	90	90	2007	2007	$1,500	$2,500

Electricity Market Module

Electricity Market Module

The electricity market module (EMM) represents the generation, transmission, and pricing of electricity, subject to: delivered prices for coal, petroleum products, and natural gas; the cost of centralized generation from renewable fuels; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. The submodules consist of capacity planning, fuel dispatching, finance and pricing, and load and demand (Figure 9). In addition, nonutility supply and electricity trade are represented in the fuel dispatching and capacity planning submodules. Nonutility generation from CHP and other facilities whose primary business is not electricity generation is represented in the demand and fuel supply modules. All other nonutility generation is represented in the EMM. The generation of electricity is accounted for in 15 supply regions (Figure 10), and fuel consumption is allocated to the 9 Census divisions.

The EMM determines airborne emissions produced by the generation of electricity. It represents limits for sulfur dioxide and nitrogen oxides specified in the Clean Air Act Amendments of 1990 (CAAA90) and the Clean Air Interstate Rule. The *AEO2009* also models State-level regulations implementing mercury standards. The EMM also has the ability to track and limit emissions of carbon dioxide, and the *AEO2009* includes the regional carbon restrictions of the Regional Greenhouse Gas Initiative (RGGI).

Operating (dispatch) decisions are provided by the cost-minimizing mix of fuel and variable operating and maintenance (O&M) costs, subject to environmental costs. Capacity expansion is determined by the least-cost mix of all costs, including capital, O&M, and fuel. Electricity demand is represented by load curves, which vary by region and season. The solution to the submodules of EMM is simultaneous in that, directly or indirectly, the solution for each submodule depends on the solution to every other submodule. A solution sequence through the submodules can be viewed as follows:

- The electricity load and demand submodule processes electricity demand to construct load curves
- The electricity capacity planning submodule projects the construction of new utility and nonutility plants, the level of firm power trades, and the addition of equipment for environmental compliance
- The electricity fuel dispatch submodule dispatches the available generating units, both utility and nonutility, allowing surplus capacity in select regions to be dispatched to meet another regions needs (economy trade)
- The electricity finance and pricing submodule calculates total revenue requirements for each operation and computes average and marginal-cost based electricity prices.

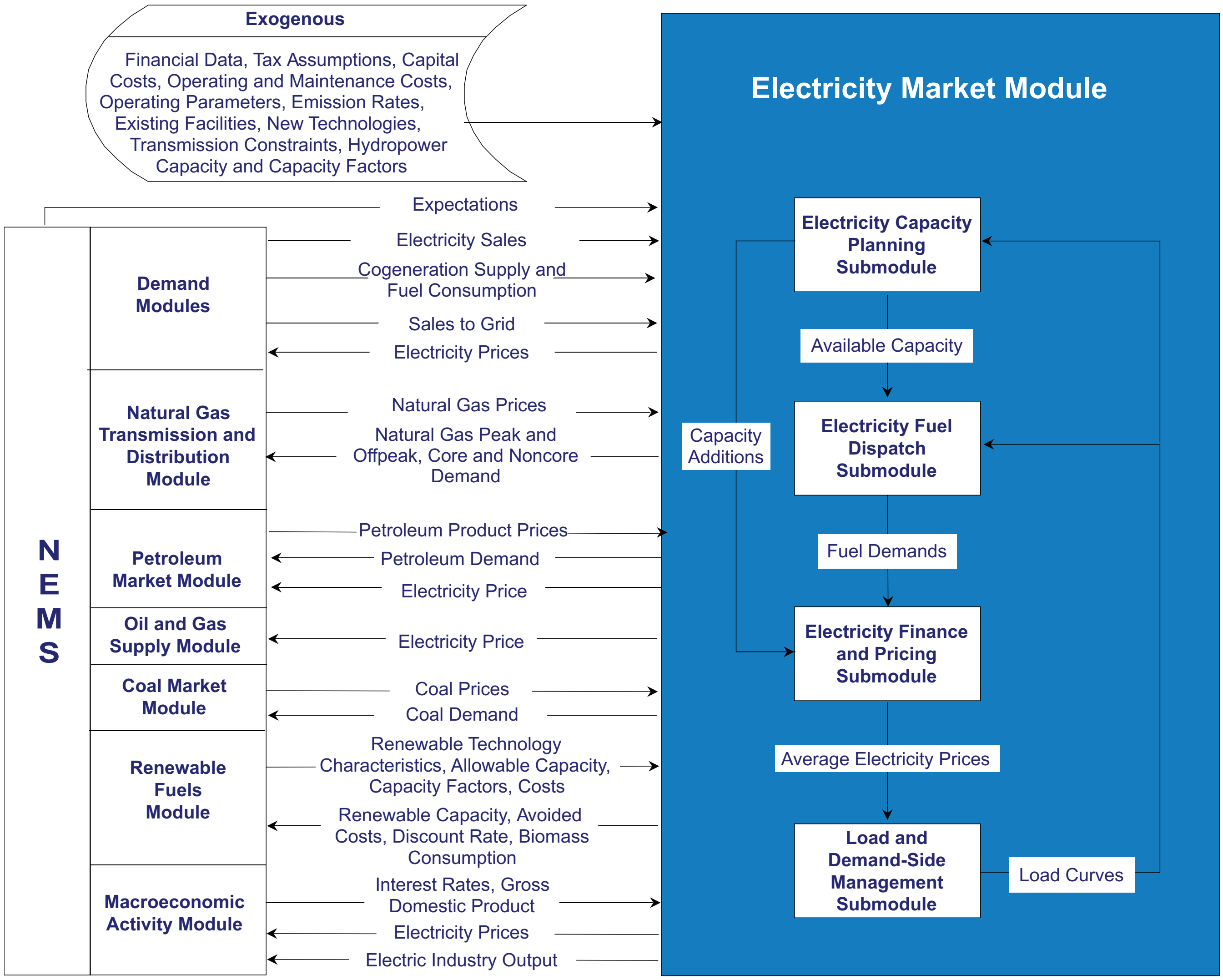
Electricity Capacity Planning Submodule

The electricity capacity planning (ECP) submodule determines how best to meet expected growth in electricity demand, given available resources, expected load shapes, expected demands and fuel prices, environmental constraints, and costs for utility and nonutility technologies. When new capacity is required to meet growth in electricity demand, the technology chosen is determined by the timing of the demand increase, the expected utilization of the new capacity, the operating efficiencies, and the construction and operating costs of available technologies.

The expected utilization of the capacity is important in the decision-making process. A technology with relatively high capital costs but comparatively low operating costs (primarily fuel costs) may be the appropriate choice if the capacity is expected to operate continuously (base load). However, a plant type with high operating costs but low capital costs may be the most economical selection to serve the peak load (i.e., the highest demands on the system), which occurs infrequently. Intermediate or cycling load occupies a middle ground between base and peak load and is best served

EMM Outputs	Inputs from NEMS	Exogenous Inputs
Electricity prices and price components Fuel demands Capacity additions Capital requirements Emissions Renewable capacity Avoided costs	Electricity sales Fuel prices Cogeneration supply and fuel consumption Electricity sales to the grid Renewable technology characteristics, allowable capacity, and costs Renewable capacity factors Gross domestic product Interest rates	Financial data Tax assumptions Capital costs Operation and maintenance costs Operating parameters Emmissions rates New technologies Existing facilities Transmission constraints

Figure 9. Electricity Market Module Strucuture



by plants that are cheaper to build than baseload plants and cheaper to operate than peak load plants.

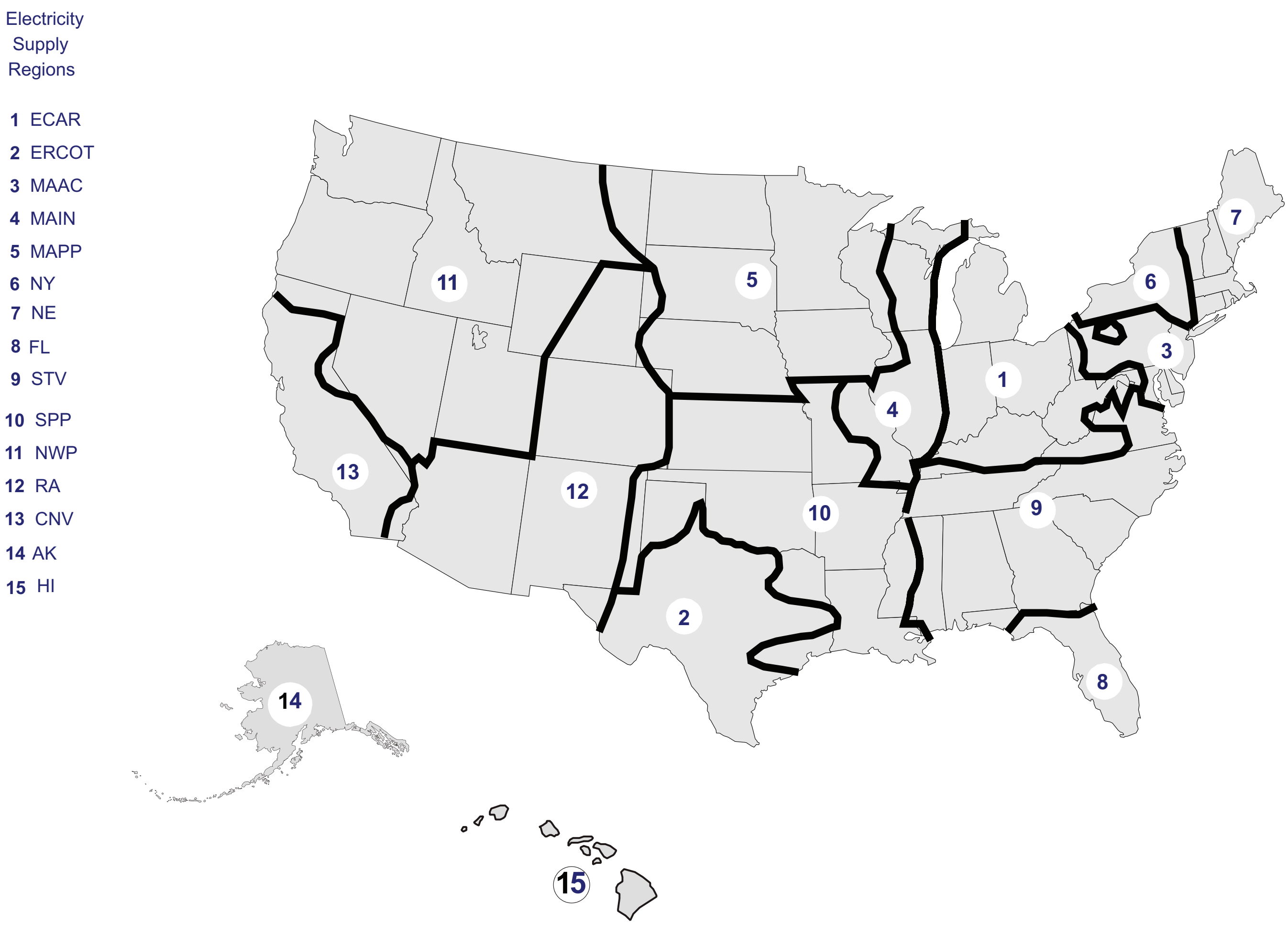
Technologies are compared on the basis of total capital and operating costs incurred over a 20-year period. As new technologies become available, they are competed against conventional plant types. Fossil-fuel, nuclear, and renewable central-station generating technologies are represented, as listed in Table 11. The EMM also considers two distributed generation technologies -baseload and peak. The EMM also has the ability to model a demand storage technology to represent load shifting.

Uncertainty about investment costs for new technologies is captured in ECP using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.

Learning factors represent reductions in capital costs due to learning-by-doing. For new technologies, cost reductions due to learning also account for international experience in building generating capacity. These factors

Electricity Market Module

Figure 10. Electricity Market Module Supply Regions



are calculated for each of the major design components of a plant type design. For modeling purposes, components are identified only if the component is shared between multiple plant types, so that the ECP can reflect the learning that occurs across technologies. The cost adjustment factors are based on the cumulative capacity of a given component. A 3-step learning curve is utilized for all design components.

Typically, the greatest amount of learning occurs during the initial stages of development and the rate of cost reductions declines as commercialization progresses. Each step of the curve is characterized by the learning rate and the number of doublings of capacity in which this rate is applied. Depending on the stage of development for a particular component, some of the learning may already be incorporated in the initial cost estimate.

Capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new technologies are assumed to contribute to reductions in capital costs for units that are installed in the United States to the extent that (1) the technology characteristics are similar to those used in U.S. markets, (2) the design and construction firms and key personnel compete in the U.S. market, (3) the owning and operating firm competes actively in the United States, and (4) there exists relatively complete information about the status of the associated facility. If the new foreign units do not satisfy one or more of these requirements, they are given a reduced weight or not included in the learning effects calculation. Capital costs, heat rates, and first year of availablilty from the *AEO2009* reference case are shown in Table 12; capital costs represent the costs of building new plants ordered in 2008. Additional information about costs and performance characteristics can be found on page 89 of the "Assumptions to the Annual Energy Outlook 2009."[17]

Initially, investment decisions are determined in ECP using cost and performance characteristics that are represented as single point estimates corresponding to the average (expected) cost. However, these parameters are also subject to uncertainty and are better represented by distributions. If the distributions of two or more options overlap, the option with the lowest average cost is not likely to capture the entire market. Therefore, ECP uses a market-sharing algorithm to adjust the initial solution and reallocate some of the capacity expansion decisions to technologies that are competitive but do not have the lowest average cost.

Fossil-fired steam and nuclear plant retirements are calculated endogenously within the model. Plants are retired if the market price of electricity is not sufficient to support continued operation. The expected revenues from these plants are compared to the annual going-forward costs, which are mainly fuel and O&M costs. A plant is retired if these costs exceed the revenues and the overall cost of electricity can be reduced by building replacement capacity.

The ECP submodule also determines whether to contract for unplanned firm power imports from Canada and from neighboring electricity supply regions. Imports from Canada are competed using supply curves developed from cost estimates for potential hydroelectric projects in Canada. Imports from neighboring electricity supply regions are competed in the ECP based on the cost of the unit in the exporting region plus the additional cost of transmitting the power. Transmission costs are computed as a fraction of revenue.

After building new capacity, the submodule passes total available capacity to the electricity fuel dispatch submodule and new capacity expenses to the electricity finance and pricing submodule.

Electricity Fuel Dispatch Submodule

Given available capacity, firm purchased-power agreements, fuel prices, and load curves, the electricity fuel dispatch (EFD) submodule minimizes variable costs as it solves for generation facility utilization and economy power exchanges to satisfy demand in each time period and region. Limits on emissions of sulfur dioxide from generating units and the engineering characteristics of units serve as constraints. Coal-fired capacity can co-fire with biomass in order to lower operating costs and/or emissions.

The EFD uses a linear programming (LP) approach to provide a minimum cost solution to allocating (dispatching) capacity to meet demand. It simulates the electric transmission network on the NERC region level and simultaneously dispatches capacity regionally by time slice until demand for the year is met. Traditional cogeneration and firm trade capacity is removed from the load duration curve prior to the dispatch decision. Capacity costs for each time slice are based on fuel and variable O&M costs, making adjustments for RPS

Table 11. Generating Technologies

Fossil
Existing coal steam plants (with or without environmental controls) New pulverized coal with environmental controls Advanced clean coal technology Advanced clean coal technology with sequestration Oil/Gas steam Conventional combined cycle Advanced combined cycle Advanced combined cycle with sequestration Conventional combustion turbine Fuel cells
Nuclear
Conventional nuclear Advanced nuclear
Renewables
Conventional hydropower Pumped storage Geothermal Solar-thermal Solar-photovoltaic Wind - onshore and offshore Wood Municipal solid waste
Environmental controls include flue gas desulfurization (FGD), selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), fabric filters, spray cooling, activated carbon injection (ACI), and particulate removal equipiment.

17 Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2009).pdf (March 2009)

credits, if applicable, and production tax credits. Generators are required to meet planned maintenance requirements, as defined by plant type.

Interregional economy trade is also represented in the EFD submodule by allowing surplus generation in one region to satisfy electricity demand in an importing region, resulting in a cost savings. Economy trade with Canada is determined in a similar manner as interregional economy trade. Surplus Canadian energy is allowed to displace energy in an importing region if it results in a cost savings. After dispatching, fuel use is reported back to the fuel supply modules and operating expenses and revenues from trade are reported to the electricity finance and pricing submodule.

Electricity Finance and Pricing Submodule

The costs of building capacity, buying power, and generating electricity are tallied in the electricity finance and pricing (EFP) submodule, which simulates both competitive electricity pricing and the cost-of-service method often used by State regulators to determine the price of electricity. The AEO2009 reference case assumes a transition to full competitive pricing in New York, Mid-Atlantic Area Council, and Texas, and a 95 percent transition to competitive pricing in New England (Vermont being the only fully-regulated State in that region). California returned to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998. In addition electricity prices in the

Table 12. 2008 Overnight Capital Costs (including Contingencies), 2008 Heat Rates, and Online Year by Technology for the AEO2009 Reference Case

Technology	Capital Costs[1] (2007$/KW)	Heatrate in 2008 (Btu/kWhr)	Online Year[2]
Scrubbed Coal New	2058	9200	2012
Integrated Coal-gasification Comb Cycle (IGCC)	2378	8765	2012
IGCC with carbon sequestration	3496	10781	2016
Coventional Gas/Oil Comb Cycle	962	7196	2011
Advanced Gas/Oil Comb Cycle (CC)	948	6752	2011
Advanced CC with carbon sequestration	1890	8613	2016
Conventional Combusion Turbine	670	10810	2010
Advanced Combusition Turbine	634	9289	2010
Fuel Cells	5360	7930	2011
Adv nuclear	3318	10434	2016
Distributed Generation - Base	1370	9050	2011
Distributed Generation - Peak	1645	10069	2010
Biomass	3766	9646	2012
MSW - Landfill Gas	2543	13648	2010
Geothermal[3]	1711	34633	2010
Conventional Hydropower [3,4]	2242	9919	2012
Wind[4]	1923	9919	2009
Wind Offshore[4]	3851	9919	2012
Solar Thermal	5021	9919	2012
Photovoltaic	6038	9919	2011

[1]Overnight capital cost including contingency factors, excluding reigonal multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2008. Capital costs are shown before investment tax credits are applied, where applicable.

[2]Online year represents the first year that a new unit could be completed, given an order date of 2008. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge the significant market activity already occuring in anticipation of the expiration of the Production Tax Credit in 2009 for wind and 2010 for the others.

[3]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[4]For hydro, wind, and solar technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2007. This isused for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

East Central Area Reliability Council, the Mid-American Interconnected Network, the Southeastern Electric Reliability Council, the Southwest Power Pool, the Northwest Power Pool, and the Rocky Mountain Power Area/Arizona are a mix of both competitive and regulated prices. Since some States in each of these regions have not taken action to deregulate their pricing of electricity, prices in those States are assumed to continue to be based on traditional cost-of-service pricing. The price for mixed regions is a load-weighted average of the competitive price and the regulated price, with the weight based on the percent of electricity load in the region that has taken action to deregulate. In regions where none of the states in the region have introduced competition—Florida Reliability Coordinating Council and Mid-Continent Area Power Pool—electricity prices are assumed to remain regulated and the cost-of-service calculation is used to determine electricity prices.

Using historical costs for existing plants (derived from various sources such as Federal Energy Regulatory Commission Form 1, Annual Report of Major Electric Utilities, Licensees and Others, and Form EIA-412, Annual Report of Public Electric Utilities), cost estimates for new plants, fuel prices from the NEMS fuel supply modules, unit operating levels, plant decommissioning costs, plant phase-in costs, and purchased power costs, the EFP submodule calculates total revenue requirements for each area of operation—generation, transmission, and distribution—for pricing of electricity in the fully regulated States. Revenue requirements shared over sales by customer class yield the price of electricity for each class. Electricity prices are returned to the demand modules. In addition, the submodule generates detailed financial statements.

For those States for which it is applicable, the EFP also determines competitive prices for electricity generation. Unlike cost-of-service prices, which are based on average costs, competitive prices are based on marginal costs. Marginal costs are primarily the operating costs of the most expensive plant required to meet demand. The competitive price also includes a reliability price adjustment, which represents the value consumers place on reliability of service when demands are high and available capacity is limited. Prices for transmission and distribution are assumed to remain regulated, so the delivered electricity price under competition is the sum of the marginal price of generation and the average price of transmission and distribution.

Electricity Load and Demand Submodule

The electricity load and demand (ELD) submodule generates load curves representing the demand for electricity. The demand for electricity varies over the course of a day. Many different technologies and end uses, each requiring a different level of capacity for different lengths of time, are powered by electricity. For operational and planning analysis, an annual load duration curve, which represents the aggregated hourly demands, is constructed. Because demand varies by geographic area and time of year, the ELD submodule generates load curves for each region and season.

Emissions

EMM tracks emission levels for sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Facility development, retrofitting, and dispatch are constrained to comply with the pollution constraints of the CAAA90 and other pollution constraints including the Clean Air Interstate Rule. An innovative feature of this legislation is a system of trading emissions allowances. The trading system allows a utility with a relatively low cost of compliance to sell its excess compliance (i.e., the degree to which its emissions per unit of power generated are below maximum allowable levels) to utilities with a relatively high cost of compliance. The trading of emissions allowances does not change the national aggregate emissions level set by CAAA90, but it does tend to minimize the overall cost of compliance.

In addition to SO_2, and NO_x, the EMM also determines mercury and carbon dioxide emissions. It represents control options to reduce emissions of these four gases, either individually or in any combination. Fuel switching from coal to natural gas, renewables, or nuclear can reduce all of these emissions. Flue gas desulfurization equipment can decrease SO_2 and mercury emissions. Selective catalytic reduction can reduce NO_x and mercury emissions. Selective non-catalytic reduction and low-NO_x burners can lower NO_x emissions. Fabric filters and activated carbon injection can reduce mercury emissions. Lower emissions resulting from demand reductions are determined in the end-use demand modules.

The *AEO2009* includes a generalized structure to model current state-level regulations calling for the best available control technology to control mercury. The *AEO2009* also includes the carbon caps for States that are part of the RGGI.

Renewable Fuels Module

Renewable Fuels Module

The renewable fuels module (RFM) represents renewable energy resoures and large–scale technologies used for grid-connected U.S. electricity supply (Figure 11). Since most renewables (biomass, conventional hydroelectricity, geothermal, landfill gas, solar photovoltaics, solar thermal, and wind) are used to generate electricity, the RFM primarily interacts with the electricity market module (EMM).

New renewable energy generating capacity is either model–determined or based on surveys or other published information. A new unit is only included in surveys or acccepted from published information if it is reported to or identified by the EIA and the unit meets EIA criteria for inclusion (the unit exists, is under construction, under contract, is publicly declared by the vendor, or is mandated by state law, such as under a state renewable portfolio standard). EIA may also assume minimal builds for reasons based on historical experience (floors). The penetration of grid-connected renewable energy generating technologies, with the exception of landfill gas, is determined by the EMM.

Each renewable energy submodule of the RFM is treated independently of the others, except for their least-cost competition in the EMM. Because variable operation and maintenance costs for renewable technologies are lower than for any other major generating technology, and because they generally produce little or no air pollution, all available renewable capacity, except biomass, is assumed to be dispatched first by the EMM. Because of its potentially significant fuel cost, biomass is dispatched according to its variable cost by the EMM.

With significant growth over time, installation costs are assumed to be higher because of growing constraints on the availability of sites, natural resource degradation, the need to upgrade existing transmission or distribution networks, and other resource-specific factors.

Geothermal-Electric Submodule

The geothermal-electric submodule provides the EMM the amounts of new geothermal capacity that can be built at known and well characterized geothermal resource sites, along with related cost and performance data. The information is expressed in the form of a three–step supply function that represents the aggregate amount of new capacity and associated costs that can be offered in each year in each region.

Only hydrothermal (hot water and steam) resources are considered. Hot dry rock resources are not included, because they are not expected to be economically accessible during the NEMS projection horizon.

Capital and operating costs are estimated separately, and life-cycle costs are calculated by the RFM. The costing methodology incorporates any applicable effects of Federal and State energy tax construction and production incentives

Wind-Electric Submodule

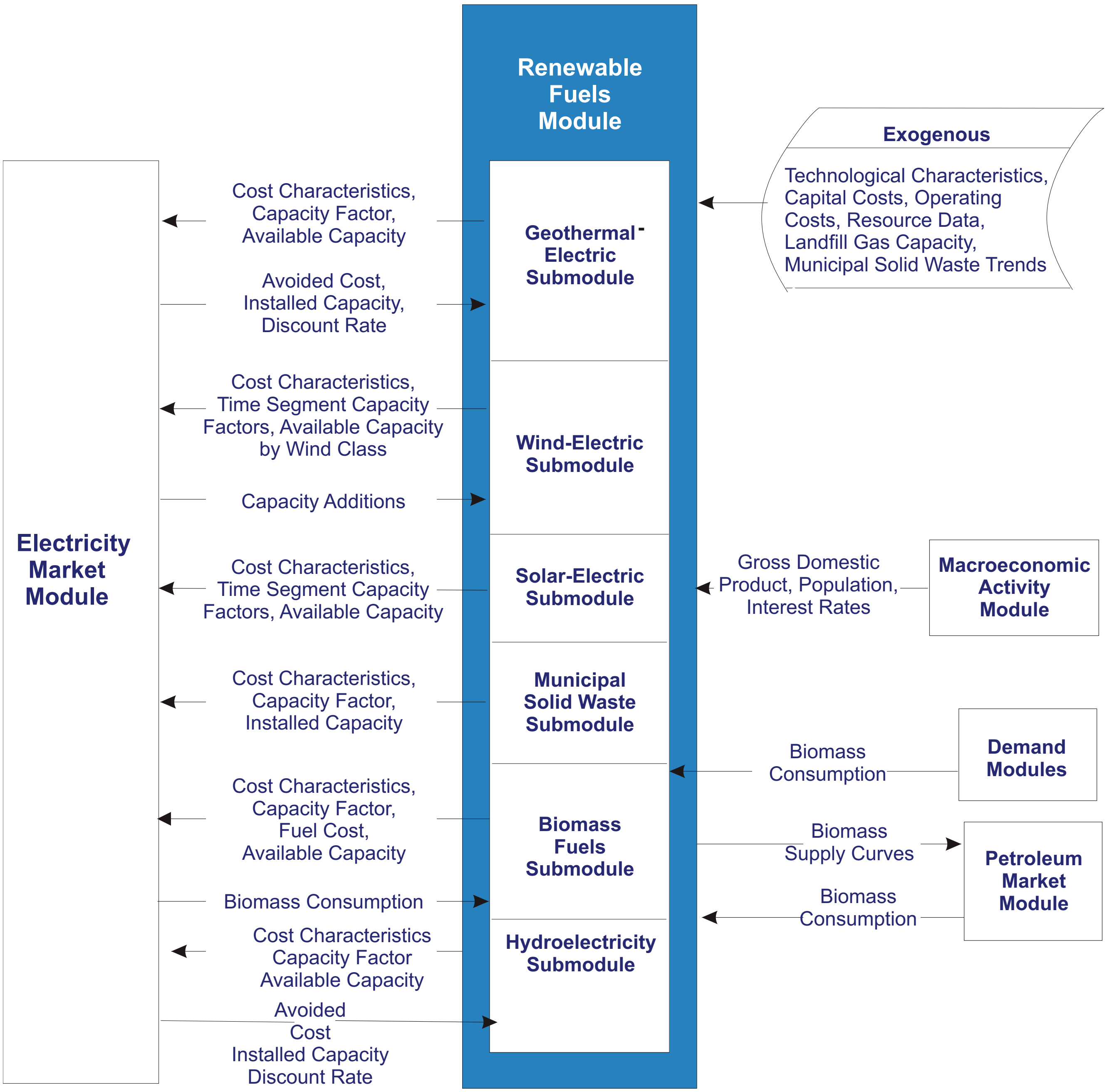
The wind-electric submodule projects the availability of wind resources as well as the cost and performance of wind turbine generators. This information is passed to EMM so that wind turbines can be built and dispatched in competition with other electricity generating technologies. The wind turbine data are expressed in the form of energy supply curves that provide the maximum amount, capital cost, and capacity factor of turbine generating capacity that could be installed in a region in a year, given the available land area and wind speed. The model also evaluates the contribution of the wind capacity to meeting system reliability requirements so that the EMM can appropriately incorporate wind capacity into calculations for regional reliability reserve margins.

Solar-Electric Submodule

The solar-electric submodule represents both photovoltaic and high-temperature thermal electric (concen-

RFM Outputs	Inputs from NEMS	Exogenous Inputs
Energy production capacities Capital costs Operating costs (including wood supply prices for the wood submodule) Capacity factors Available capacity Biomass fuel costs Biomass supply curves	Installed energy production capacity Gross domestic product Population Interest Rates Avoided cost of electricity Discount rate Capacity additions Biomass consumption	Site-specific geothermal resource quantity data Site-specific wind resource quality data Plant utilization (capacity factor) Technology cost and performance parameters Landfill gas capacity

Figure 11. Renewable Fuels Module Structure



trating solar power) installations. Only central-station, grid-connected applications constructed by a utility or independent power producer are considered in this portion of the model.

The solar-electric submodule provides the EMM with time-of-day and seasonal solar availability data for each region, as well as current costs. The EMM uses this data to evaluate the cost and performance of solar-electric technologies in regional grid applications. The commercial and residential demand modules of NEMS also model photovoltaic systems installed by consumers, as discussed in the demand module descriptions under “Distributed Generation.”

Landfill Gas Submodule

The landfill gas submodule provides annual projections of electricity generation from methane from landfills (landfill gas). The submodule uses the quantity of municipal solid waste (MSW) that is produced, the proportion of MSW that will be recycled, and the methane emission characteristics of three types of landfills to produce projections of the future electric power generating capacity from landfill gas. The amount of methane available is calculated by first determining the amount of total waste generated in the United States. The amount of total waste generated is derived from an econometric equation that uses gross domestic product and population as the projection drivers. It is assumed that no new mass burn waste–to–energy (MSW) facilities will be built and operated during the projection period in the United States. It is also assumed that operational mass-burn facilities will continue to operate and retire as planned throughout the projection period. The landfill gas submodule passes cost and performance characteristics of the landfill gas–to–electricity technology to the EMM for capacity planning decisions. The amount of new land-fill-gas-to-electricity capacity competes with other technologies using supply curves that are based on the amount of high, medium, and low methane producing landfills located in each EMM region.

Biomass Fuels Submodule

The biomass fuels submodule provides biomass-fired plant technology characterizations (capital costs, operating costs, capacity factors, etc.) and fuel information for EMM, thereby allowing biomass-fueled power plants to compete with other electricity generating technologies.

Biomass fuel prices are represented by a supply curve constructed according to the accessibility of resources to the electricity generation sector. The supply curve employs resource inventory and cost data for four categories of biomass fuel - urban wood waste and mill residues, forest residues, energy crops, and agricultural residues. Fuel distribution and preparation cost data are built into these curves. The supply schedule of biomass fuel prices is combined with other variable operating costs associated with burning biomass. The aggregate variable cost is then passed to EMM.

Hydroelectricity Submodule

The hydroelectricity submodule provides the EMM the amounts of new hydroelectric capacity that can be built at known and well characterized sites, along with related cost and performance data. The information is expressed in the form of a three–step supply function that represents the aggregate amount of new capacity and associated costs that can be offered in each year in each region. Sites include undeveloped stretches of rivers, existing dams or diversions that do not currently produce power, and existing hydroelectric plants that have known capability to expand operations through the addition of new generating units. Capacity or efficiency improvements through the replacement of existing equipment or changes to operating procedures at a facility are not included in the hydroelectricity supply.

Oil And Gas Supply Module

Oil and Gas Supply Module

The OGSM consists of a series of process submodules that project the availability of domestic crude oil production and dry natural gas production from onshore, offshore, and Alaskan reservoirs, as well as conventional gas production from Canada. The OGSM regions are shown in Figure 12.

The driving assumption of OGSM is that domestic oil and gas exploration and development are undertaken if the discounted present value of the recovered resources at least covers the present value of taxes and the cost of capital, exploration, development, and production. Crude oil is transported to refineries, which are simulated in the PMM, for conversion and blending into refined petroleum products. The individual submodules of the OGSM are solved independently, with feedbacks achieved through NEMS solution iterations (Figure 13).

Technological progress is represented in OGSM through annual increases in the finding rates and success rates, as well as annual decreases in costs. For conventional onshore, a time trend was used in econometrically estimated equations as a proxy for technology. Reserve additions per well (or finding rates) are projected through a set of equations that distinquish between new field discoveries and discoveries (extensions) and revisions in known fields. The finding rate equations capture the impacts of technology, prices, and declining resources. Another representation of technology is in the success rate equations. Success rates capture the impact of technology and saturation of the area through cumulative drilling. Technology is further represented in the determination of drilling, lease equipment, and operating costs. Technological progress puts downward pressure on the drilling, lease equipment, and operating cost projections. For unconventional gas, a series of eleven different technology groups are represented by time–dependent adjustments to factors which influence finding rates, success rates, and costs.

Conventional natural gas production in Western Canada is modeled in OGSM with three econometrically estimated equations: total wells drilled, reserves added per well, and expected production-to-reserves ratio. The model performs a simple reserves accounting and applies the expected production-to-reserve ratio to estimate an expected production level, which in turn is used to establish a supply curve for conventional Western Canada natural gas. The rest of the gas production sources in Canada are represented in the Natural Gas Transmission and Distribution Module (NGTDM).

Lower 48 Onshore and Shallow Offshore Supply Submodule

The lower 48 onshore supply submodule projects crude oil and natural gas production from conventional recovery techniques. This submodule accounts for drilling, reserve additions, total reserves, and production -to-reserves ratios for each lower 48 onshore supply region.

The basic procedure is as follows:

- First, the prospective costs of a representative drilling project for a given fuel category and well class within a given region are computed. Costs are a function of the level of drilling activity, average well depth, rig availability, and the effects of technological progress.
- Second, the present value of the discounted cash flows (DCF) associated with the representative project is computed. These cash flows include both the capital and operating costs of the project, including royalties and taxes, and the revenues derived from a declining well production profile, computed after taking into account the progressive effects of resource depletion and valued at constant real prices as of the year of initial valuation.
- Third, drilling levels are calculated as a function of projected profitability as measured by the projected DCF levels for each project and national level cashflow.

OGSM Outputs	Inputs from NEMS	Exogenous Inputs
Crude oil production Domestic nonassociated and Canadian conventional natural gas suply curves Cogeneration from oil and gas producton Reserves and reserve additions Drilling levels Domestic associated-dissolved gas production	Domestic and Canadian natural gas production and wellhead prices Crude oil demand World oil price Electricity price Gross domestic product Inflation rate	Resource levels Initial finding rate parameters and costs Production profiles Tax parameters

Figure 12. Oil and Gas Supply Module Regions

- Fourth, regional finding rate equations are used to project new field discoveries from new field wildcats, new pools, and extensions from other exploratory drilling, and reserve revisions from development drilling.
- Fifth, production is determined on the basis of reserves, including new reserve additions, previous productive capacity, flow from new wells, and, in the case of natural gas, fuel demands. This occurs within the market equilibration of the NGTDM for natural gas and within OGSM for oil.

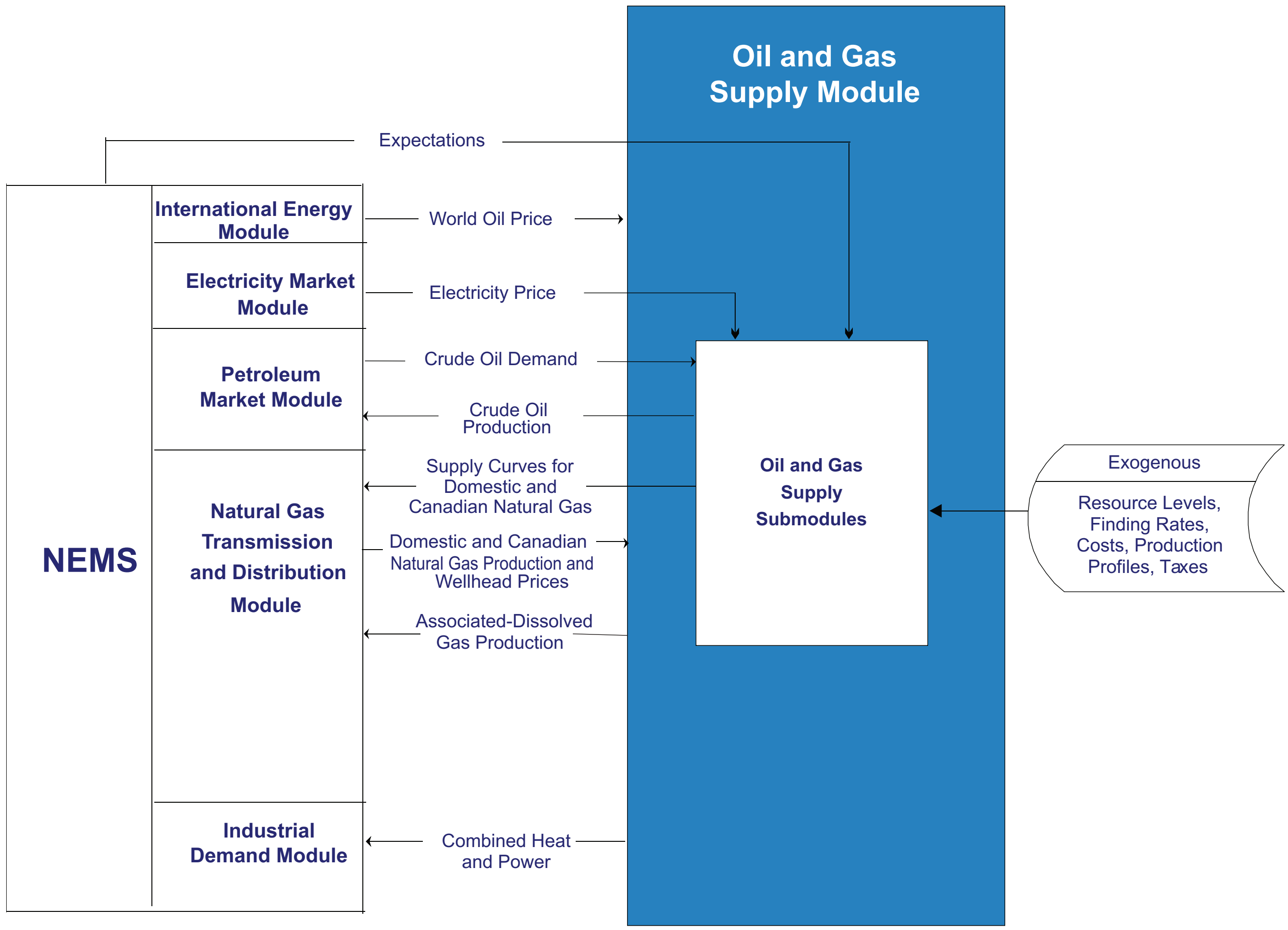
Unconventional Gas Recovery Supply Submodule

Unconventional gas is defined as gas produced from nonconventional geologic formations, as opposed to conventional (sandstones) and carbonate rock formations. The three unconventional geologic formations considered are low–permeability or tight sandstones, gas shales and coalbed methane.

For unconventional gas, a play–level model calculates the economic feasibility of individual plays based on locally specific wellhead prices and costs, resource quantity and quality, and the various effects of technology on both resources and costs. In each year, an initial resource characterization determines the expected ultimate recovery (EUR) for the wells drilled in a particular play. Resource profiles are adjusted to reflect assumed technological impacts on the size, availability, and industry knowledge of the resources in the play.

Oil and Gas Supply Module

Figure 13. Oil and Gas Supply Module Structure



Subsequently, prices received from NGTDM and endogenously determined costs adjusted to reflect technological progress are utilized to calculate the economic profitability (or lack thereof) for the play. If the play is profitable, drilling occurs according to an assumed schedule, which is adjusted annually to account for technological improvements, as well as varying economic conditions. This drilling results in reserve additions, the quantities of which are directly related to the EURs for the wells in that play. Given these reserve additions, reserve levels and expected production–to–reserves (P/R) ratios are calculated at both the OGSM and the NGTDM region level. The resultant values are aggregated with similar values from the conventional onshore and offshore submodules. The aggregate P/R ratios and reserve levels are then passed to NGTDM, which determines the prices and production for the following year through market equilibration.

Offshore Supply Submodule

This submodule uses a field-based engineering approach to represent the exploration and development of U.S. offshore oil and natural gas resources. The submodule simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore resources are divided into 3 categories:

- **Undiscovered Fields.** The number, location, and size of the undiscovered fields are based on the MMS's 2006 hydrocarbon resource assessment.
- **Discovered, Undeveloped Fields.** Any discovery that has been announced but is not currently producing is evaluated in this component of the model. The first production year is an input and is based on announced plans and expectations.

- **Producing Fields.** The fields in this category have wells that have produced oil and/or gas through the year prior to the AEO projection. The production volumes are from the Minerals Management Service (MMS) database.

Resource and economic calculations are performed at an evaluation unit basis. An evaluation unit is defined as the area within a planning area that falls into a specific water depth category. Planning areas are the Western Gulf of Mexico (GOM), Central GOM, Eastern GOM, Pacific, and Atlantic. There are six water depth categories: 0-200 meters, 200-400 meters, 400-800 meters, 800-1600 meters, 1600-2400 meters, and greater than 2400 meters.

Supply curves for crude oil and natural gas are generated for three offshore regions: Pacific, Atlantic, and GOM. Crude oil production includes lease condensate. Natural gas production accounts for both nonassociated gas and associated-dissolved gas. The model is responsive to changes in oil and natural gas prices, royalty relief assumptions, oil and natural gas resource base, and technological improvements affecting exploration and development.

Alaska Oil and Gas Submodule

This submodule projects the crude oil and natural gas produced in Alaska. The Alaskan oil submodule is divided into three sections: new field discoveries, development projects, and producing fields. Oil transportation costs to lower 48 facilities are used in conjunction with the relevant market price of oil to calculate the estimated net price received at the wellhead, sometimes called the netback price. A discounted cash flow method is used to determine the economic viability of each project at the netback price.

Alaskan oil supplies are modeled on the basis of discrete projects, in contrast to the onshore lower 48 conventional oil and gas supplies, which are modeled on an aggregate level. The continuation of the exploration and development of multiyear projects, as well as the discovery of new fields, is dependent on profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, historical production patterns, and announced plans for currently producing fields.

- Alaskan gas production is set separately for any gas targeted to flow through a pipeline to the lower 48 States and gas produced for consumption in the State and for export to Japan. The latter is set based on a projection of Alaskan consumption in the NGTDM and an exogenous specification of exports. North Slope production for the pipeline is dependent on construction of the pipeline, set to commence if the lower 48 average wellhead price is maintained at a level exceeding the established comparable cost of delivery to the lower 48 States.

Natural Gas Transmission and Distribution Module

Natural Gas Transmission And Distribution Module

The NGTDM of NEMS represents the natural gas market and determines regional market–clearing prices for natural gas supplies and for end–use consumption, given the information passed from other NEMS modules (Figure 14). A transmission and distribution network (Figure 15), composed of nodes and arcs, is used to simulate the interregional flow and pricing of gas in the contiguous United States and Canada in both the peak (December through March) and offpeak (April through November) period. This network is a simplified representation of the physical natural gas pipeline system and establishes the possible interregional flows and associated prices as gas moves from supply sources to end users.

Flows are further represented by establishing arcs from transshipment nodes to each demand sector represented in an NGTDM region (residential, commercial, industrial, electric generators, and transportation). Mexican exports and net storage injections in the offpeak period are also represented as flow exiting a transshipment node. Similarly, arcs are also established from supply points into a transshipment node. Each transshipment node can have one or more entering arcs from each supply source represented: U.S. or Canadian onshore or U.S. offshore production, liquefied natural gas imports, supplemental gas production, gas produced in Alaska and transported via pipeline, Mexican imports, or net storage withdrawals in the region in the peak period. Most of the types of supply listed above are set independently of current year prices and before NGTDM determines a market equilibrium solution.

Only the onshore and offshore lower 48 U.S. and Western Canadian Sedimentary Basin production, along with net storage withdrawals, are represented by short–term supply curves and set dynamically during the NGTDM solution process. The construction of natural gas pipelines from Alaska and Canada's MacKenzie Delta are triggered when market prices exceed estimated project costs. The flow of gas during the peak period is used to establish interregional pipeline and storage capacity requirements and the associated expansion. These capacity levels provide an upper limit for the flow during the offpeak period.

Arcs between transshipment nodes, from the transshipment nodes to end–use sectors, and from supply sources to transshipment nodes are assigned tariffs. The tariffs along interregional arcs reflect reservation (represented with volume dependent curves) and usage fees and are established in the pipeline tariff submodule. The tariffs on arcs to end–use sectors represent the interstate pipeline tariffs in the region, intrastate pipeline tariffs, and distributor markups set in the distributor tariff submodule. Tariffs on arcs from supply sources represent gathering charges or other differentials between the price at the supply source and the regional market hub. The tariff associated with injecting, storing, and withdrawing from storage is assigned to the arc representing net storage withdrawals in the peak period. During the primary solution process in the interstate transmission submodule, the tariffs along an interregional arc are added to the price at the source node to arrive at a price for the gas along the arc right before it reaches its destination node.

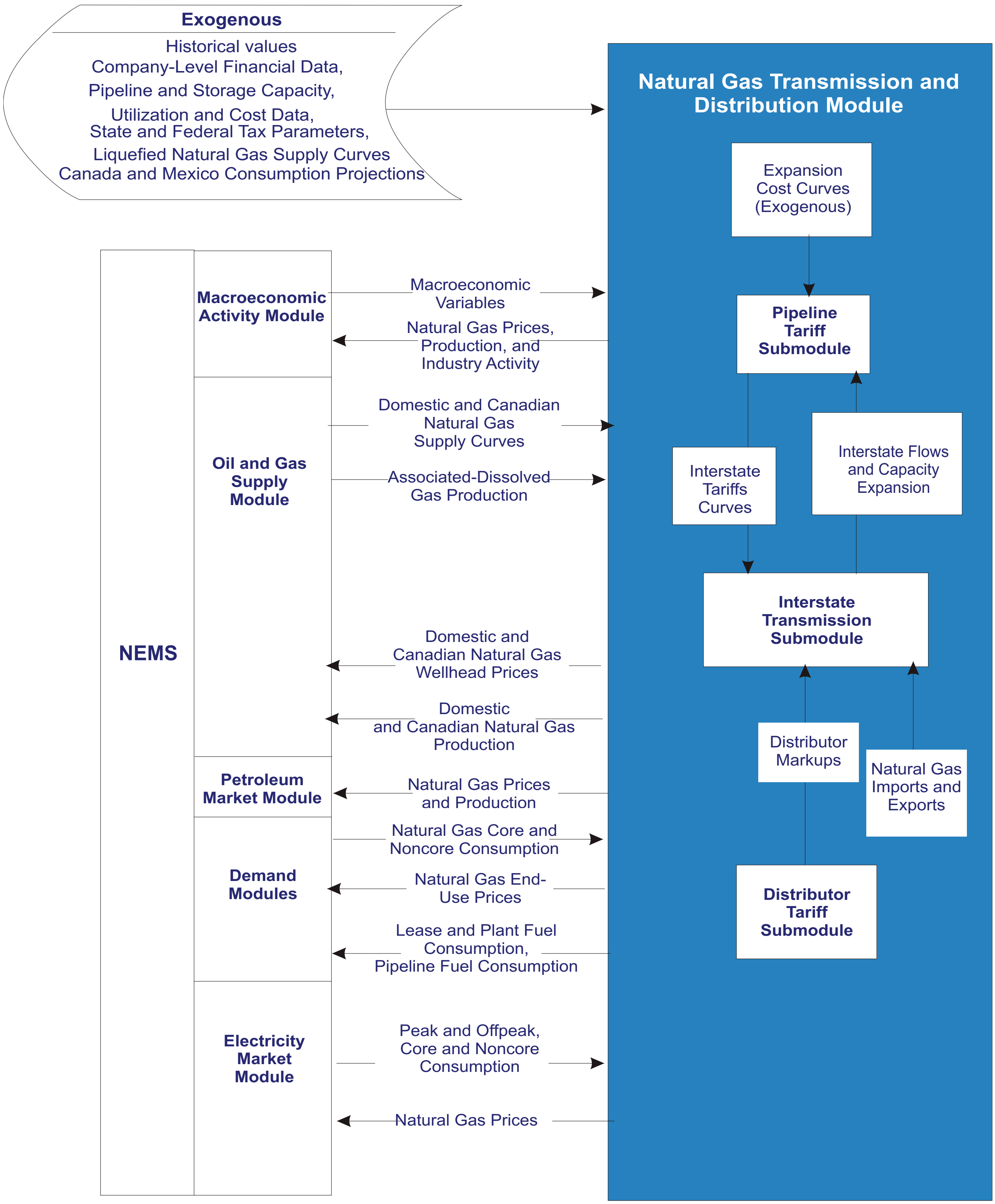
Interstate Transmission Submodule

The interstate transmission submodule (ITS) is the main integrating module of NGTDM. One of its major functions is to simulate the natural gas price determination process. ITS brings together the major economic factors that influence regional natural gas trade on a seasonal basis in the United States, the balancing of the demand for and the domestic supply of natural gas, including competition from imported natural gas. These are examined in combination with the relative prices associated with moving the gas from the producer to the end user where and when (peak versus offpeak) it is

NGTDM Outputs	Inputs from NEMS	Exogenous Inputs
Natural gas delivered prices Domestic and Canadian natural gas wellhead prices Domestic natural gas production Mexican and liquefied natural gas imports and exports Canadian natural gas imports and production Lease and plant fuel consumption Pipeline and distribution tariffs Interregional natural gas flows Storage and pipeline capacity expansion Supplemental gas production	Natural gas demands Domestic and Canadian natural gas supply curves Macroeconomic variables Associated-dissolved natural gas production	Historical consumption and flow patterns Historical supplies Pipeline company-level financial data Pipeline and storage capacity and utilization data Historical end-use citygate, and wellhead prices State and Federal tax parameters Pipeline and storage expansion cost data Liquefied natural gas supply curves Canada and Mexico consumption projections

Natural Gas Transmission And Distribution Module

Figure 14. Natural Gas Transmission and Distribution Module Structure



needed. In the process, ITS simulates the decision–making process for expanding pipeline and/or seasonal storage capacity in the U.S. gas market, determining the amount of pipeline and storage capacity to be added between or within regions in NGTDM. Storage serves as the primary link between the two seasonal periods represented.

ITS employs an iterative heuristic algorithm, along with an acyclic hierarchical representation of the primary arcs in the network, to establish a market equilibrium solution. Given the consumption levels from other NEMS modules, the basic process followed by ITS involves first establishing the backward flow of natural gas in each period from the consumers, through the network, to the producers, based primarily on the relative prices offered for the gas from the previous ITS iteration. This process is performed for the peak period first since the net withdrawals from storage during the peak period will establish the net injections during the offpeak period. Second, using the model's supply curves, wellhead and import prices are set corresponding to the desired production volumes. Also, using the pipeline and storage tariffs from the pipeline tariff submodule, pipeline and storage tariffs are set corresponding to the associated flow of gas, as determined in the first step. These prices are then translated from the producers, back through the network, to the city gate and the end users, by adding the appropriate tariffs along the way. A regional storage tariff is added to the price of gas injected into storage in the offpeak to arrive at the price of the gas when withdrawn in the peak period. This process is then repeated until the solution has converged. Finally, delivered prices are derived for residential, commercial, and transportation customers, as well as for both core and noncore industrial and electric generation sectors using the distributor tariffs provided by the distributor tariff submodule.

Pipeline Tariff Submodule

The pipeline tariff submodule (PTS) provides usage fees and volume dependent curves for computing unitized reservation fees (or tariffs) for interstate transportation and storage services within the ITS. These curves extend beyond current capacity levels and relate incremental pipeline or storage capacity expansion to corresponding estimated rates. The underlying basis for each tariff curve in the model is a projection of the associated regulated revenue requirement. Econometrically estimated equations within a general accounting framework are used to track costs and compute revenue requirements associated with both reservation and usage fees under current rate design and regulatory scenarios. Other than an assortment of macroeconomic indicators, the primary input to PTS from other modules in NEMS is pipeline and storage capacity utilization and expansion in the previous projection year.

Once an expansion is projected to occur, PTS calculates the resulting impact on the revenue requirement. PTS assumes rolled–in (or average), not incremental, rates for new capacity. The pipeline tariff curves generated by PTS are used within the ITS when determining the relative cost of purchasing and moving gas from one source versus another in the peak and offpeak seasons.

Distributor Tariff Submodule

The distributor tariff submodule (DTS) sets distributor markups charged by local distribution companies for the distribution of natural gas from the city gate to the end user. For those that do not typically purchase gas through a local distribution company, this markup represents the differential between the citygate and delivered price. End–use distribution service is distinguished within the DTS by sector (residential, commercial, industrial, electric generators, and transportation), season (peak and offpeak), and service type (core and noncore).

Distributor tariffs for all but the transportation sector are set using econometrically estimated equations. The natural gas vehicle sector markups are calculated separately for fleet and personal vehicles and account for distribution to delivery stations, retail markups, and federal and state motor fuels taxes.

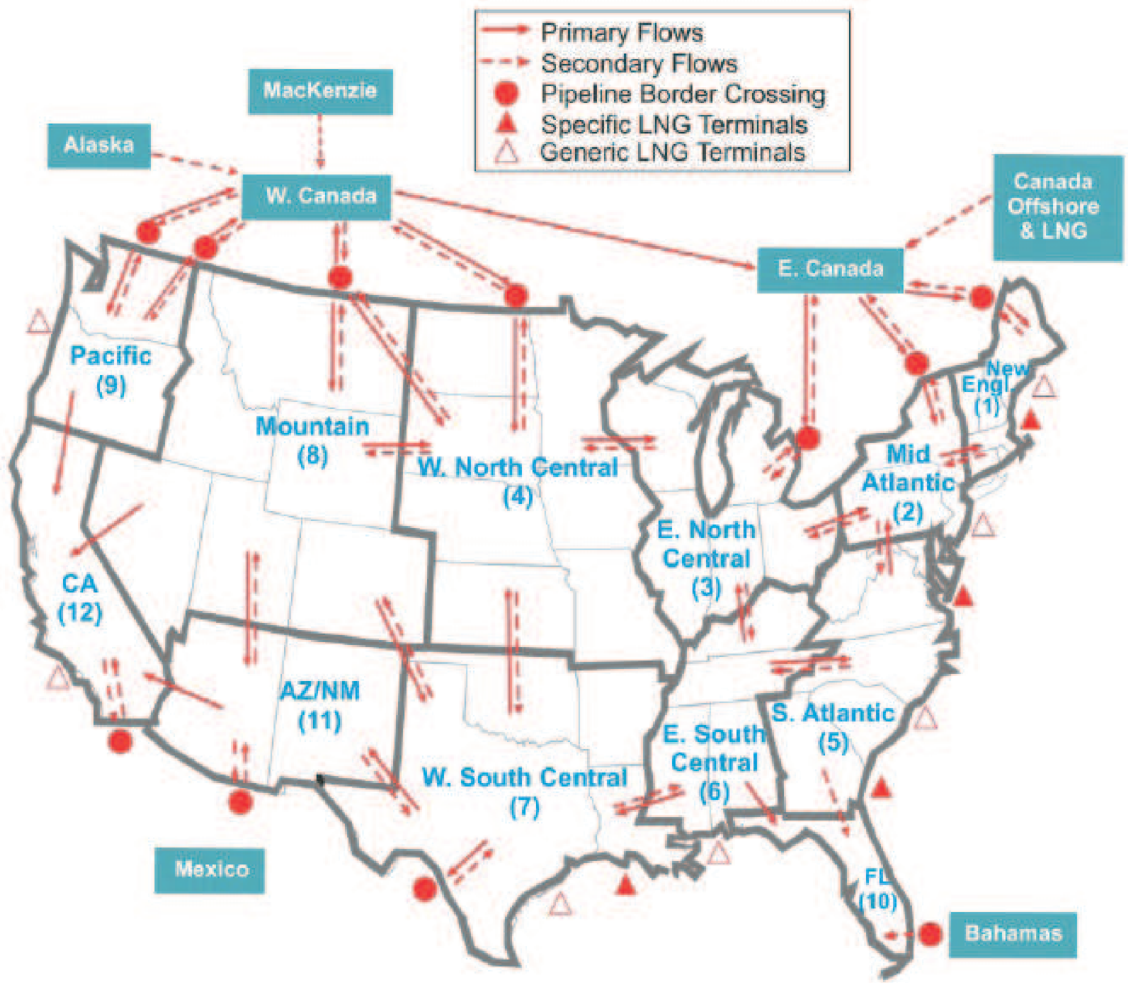
Natural Gas Imports and Exports

Liquefied natural gas imports for the U.S., Canada, and Baja, Mexico are set at the beginning of each NEMS iteration within the NGTDM by evaluating seasonal east and west supply curves, based on outputs from EIA's International Natural Gas Model, at associated regasification tailgate prices set in the previous NEMS iteration. A sharing algorithm is used to allocate the resulting import volumes to particular regions. LNG exports to Japan from Alaska are set exogenously by the OGSM.

The Mexico model is largely based on exogenously specified assumptions about consumption and production growth rates and LNG import levels. For the most part, natural gas imports from Mexico are set exogenously for each of the three border crossing points with

Natural Gas Transmission And Distribution Module

Figure 15. Natural Gas Transmission and Distribution Module Network



the United States, with the exception of any gas that is imported into Baja, Mexico in liquid form only to be exported to the United States. Exports to Mexico from the United States are established before the NGTDM equilibrates and represent the required level to balance the assumed consumption in (and exports from) Mexico against domestic production and LNG imports. The production levels are also largely assumption based, but are set to vary with changes in the expected wellhead price in the United States.

A node for east and west Canada is included in the NGTDM equilibration network, as well as seven border crossings into the United States. The model includes a representation/accounting of the U.S. border crossing pipeline capacity, east and west seasonal storage transfers, east and west consumption, east and west LNG imports, eastern production, conventional/tight sands production in the west, and coalbed/shale production. Imports from the United States, conventional production in eastern Canada, and base level natural gas consumption (which varies with the world oil price) are set exogenously. Conventional/tight sands production in the west is set using a supply curve from the OGSM. Coalbed and shale gas production are effectively based on an assumed production growth rate which is adjusted with realized prices.

Petroleum Market Module

Petroleum Market Module

The PMM represents domestic refinery operations and the marketing of liquid fuels to consumption regions. PMM solves for liquid fuel prices, crude oil and product import activity (in conjunction with the IEM and the OGSM), and domestic refinery capacity expansion and fuel consumption. The solution satisfies the demand for liquid fuels, incorporating the prices for raw material inputs, imported liquid fuels, capital investment, as well as the domestic production of crude oil, natural gas liquids, and other unconventional refinery inputs. The relationship of PMM to other NEMS modules is illustrated in Figure 16.

The PMM is a regional, linear programming formulation of the five Petroleum Administration for Defense Districts (PADDs) (Figure 17). For each region two distinct refinery are modeled. One is highly complex using over 40 different refinrry processes, while the second is defined as a simple refinery that provides marginal cost economics. Refining capacity is allowed to expand in each region, but the model does not distinguish between additions to existing refineries or the building of new facilities. Investment criteria are developed exogenously, although the decision to invest is endogenous.

PMM assumes that the petroleum refining and marketing industry is competitive. The market will move toward lower-cost refiners who have access to crude oil and markets. The selection of crude oils, refinery process utilization, and logistics (transportation) will adjust to minimize the overall cost of supplying the market with liquid fuels.

PMM's model formulation reflects the operation of domestic liquuid fuels. If demand is unusually high in one region, the price will increase, driving down demand and providing economic incentives for bringing supplies in from other regions, thus restoring the supply and demand balance.

Existing regulations concerning product types and specifications, the cost of environmental compliance, and Federal and State taxes are also modeled. PMM incorporates provisions from the Energy Independence and Security Act of 2007 (EISA2007) and the Energy Policy Act of 2005 (EPACT05). The costs of producing new formulations of gasoline and diesel fuel as a result of the CAAA90 are determined within the linear-programming representation by incorporating specifications and demands for these fuels.

PMM also includes the interaction between the domestic and international markets. Prior to AEO2009, PMM postulated entirely exogenous prices for oil on the international market (the world oil price). Subsequent AEOs include an International Energy Module (IEM) that estimates supply curves for imported crude oils and products based on, among other factors, U.S. participation in global trade of crude oil and liquid fuels.

Regions

PMM models U.S. crude oil refining capabilities based on the five PADDs which were established during World War II and are still used by EIA for data collection and analysis. The use of PADD data permits PMM to take full advantage of EIA's historical database and allows analysis within the same framework used by the petroleum industry.

PMM Outputs	Inputs from NEMS	Exogenous Inputs
Petroleum product prices Crude oil imports and exports Crude oil demand Petroleum product imports and exports Refinery activity and fuel use Ethanol demand and price Combined heat and power (CHP) Natural gas plant liquids production Processing gain Capacity additions Capital expenditures Revenues	Petroleum product demand by sector Domestic crude oil production World oil price International crude oil supply curves International product supply curves International oxygenates supply curves Natural gas prices Electricity prices Natural glas production Macroeconomic variables Biomass supply curves Coal prices	Processing unit operating parameters Processing unit capacities Product specifications Operating costs Capital costs Transmission and distribution costs Federal and State taxes Agricultural feedstock quantities and costs CHP unit operating parameters CHP unit capacities

Figure 16. Petroleum Market Module Structure

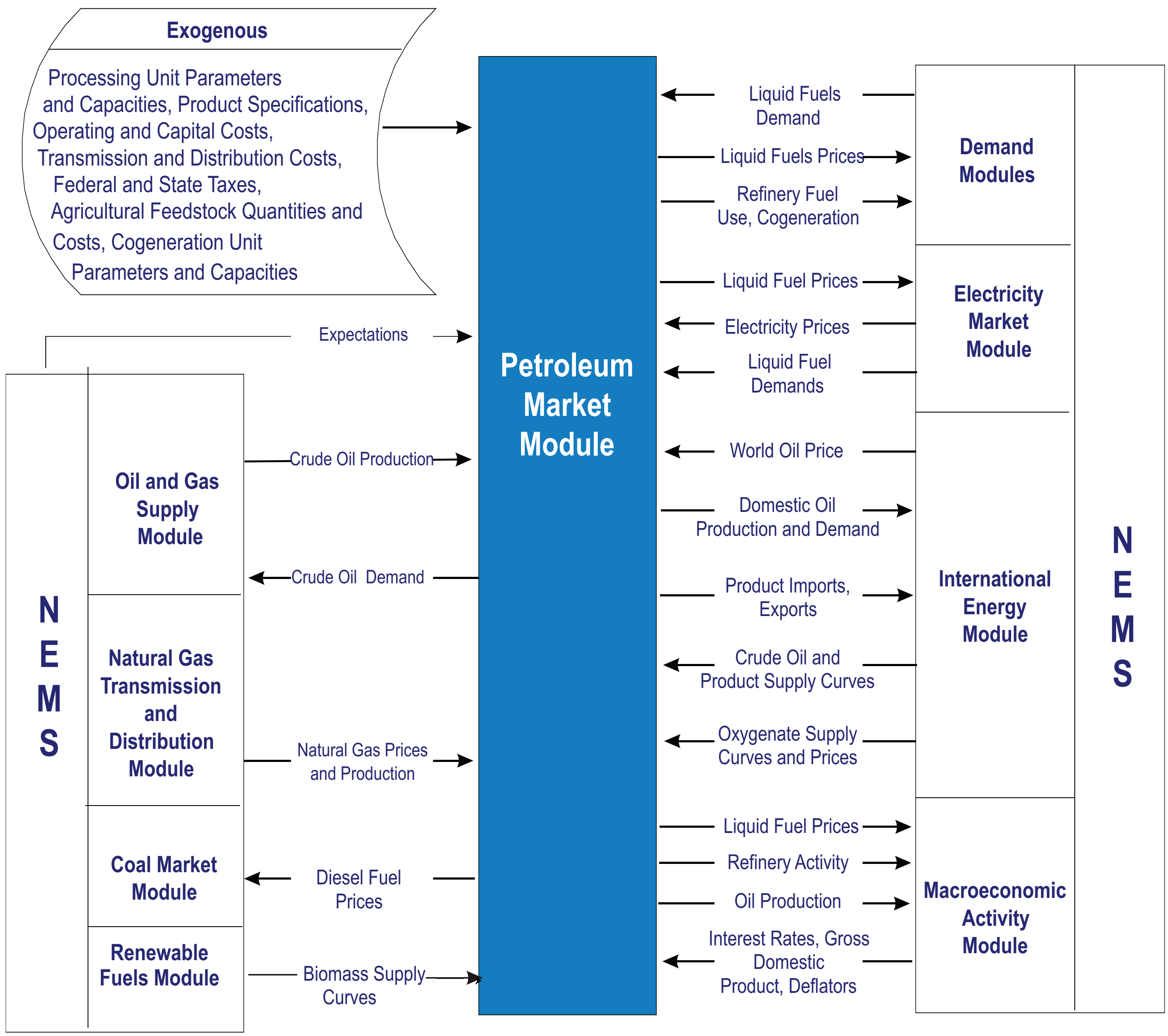
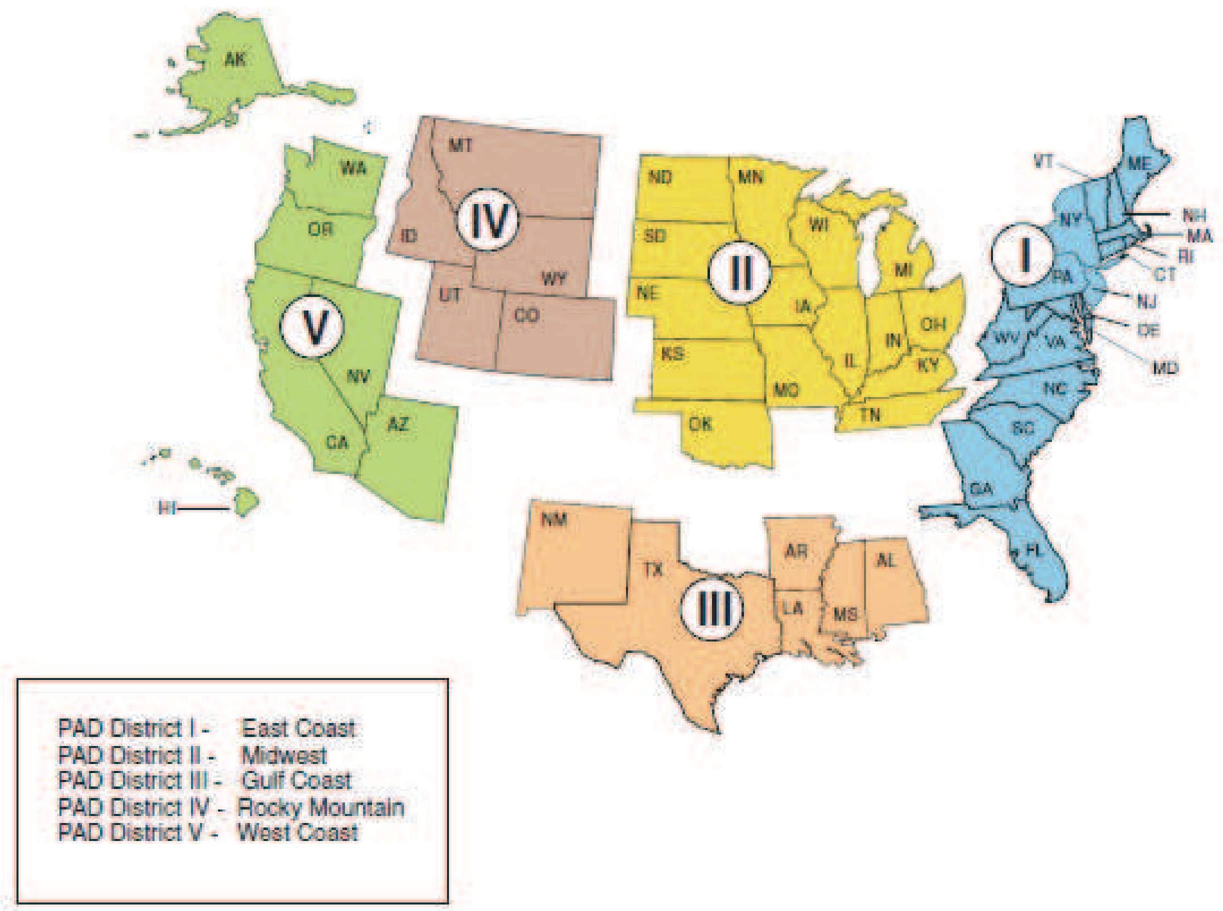


Figure 17. Petroleum Administration for Defense Districts



Product Categories

Product categories, specifications and recipe blends modeled in PMM include the following:

Liquid Fuels Modeled in PMM

Motor gasoline: conventional (oxygenated and non-oxygentated), reformulated, and California reformulated
Jet fuels: kerosene-based
Distillates: kerosene, heating oil, low sulfur (LSD) and ultra-low-sulfur (ULSD) highway diesel, distillate fuel oil, and distillate fuel from various non-crude feedstocks (coal, biomass, natural gas) via the Fischer-Tropsch process (BTL, CTL, GTL)
Alternative Fuel: Biofuels [including ethanol, biodiesel (methyl-ester), renewable diesel, biomass-to-liquids (BTL)], coal-to-liquids (CTL), gas-to-liquids (GTL).
Residual fuels: low sulfur and high sulfur residual fuel oil
Liquefied petroleum gas (LPG): a light-end mixture used for fuel in a wide range of sectors comprised primarily of propane
Natural gas plant:ethane, propane, iso and normal butane, and pentanes plus (natural gasoline)
Petrochemical feedstocks
Other: asphalt and road oil, still gas, (refinery fuel) petroleum coke, lubes and waxes, special naphthas

Fuel Use

PMM determines refinery fuel use by refining region for purchased electricity, natural gas, distillate fuel, residual fuel, liquefied petroleum gas, and other petroleum. The fuels (natural gas, petroleum, other gaseous fuels, and other) consumed within the refinery to generate electricity from CHP facilities are also determined.

Crude Oil Categories

Both domestic and imported crude oils are aggregated into five categories as defined by API gravity and sulfur content ranges. This aggregation of crude oil types allows PMM to account for changes in crude oil composition over time. A composite crude oil with the appropriate yields and qualities is developed for each category by averaging characteristics of foreign and domestic crude oil streams.

Refinery Processes

The following distinct processes are represented in the PMM:

1) Crude Oil Distillation
   a. Atmospheric Crude Unit
   b. Vacuum Crude Unit

2) Residual Oil Upgrading
   a. Coker - Delayed, fluid
   b. Thermal Cracker/Visbreaker
   c. Residuum Hydrocradker
   d. Solvent Deasphalting

3) Cracking
   a. Fluidized Catalytic Cracker
   b. Hydrocracker

4) Final Product Treating/Upgrading
   a. Traditional Hydrotreating
   b. Modern Hydrotreating
   c. Alkylation
   d. Jet Fuel Production
   e. Benzene Saturation
   f. Catalytic Reforming

5) Light End Treating
   a. Saturated Gas Plant
   b. Isomerization
   c. Dimerization/Polymerization
   d. C2-C5 Dehydrogenation

6) Non-Fuel Production
   a. Sulfur Plant
   b. Methanol Production
   c. Oxgenate Production
   d. Lube and Wax Production
   e. Steam/Power Generation
   f. Hydrogen Production
   g. Aromatics Production

7) Specialty Unit Operations
   a. Olefins to Gasoline/Diesel
   b. Methanol to Olefins

8) Merchant Facilities
   a. Coal/Gas/Biomass to Liquids
   b. Natural Gas Plant
   c. Ethanol Production
   d. Biodiesel Plant

Natural Gas Plants

Natural gas plant liquids (ethane, propane, normal butane, isobutane, and natural gasoline) produced from natural gas processing plants are modeled in PMM. Their production levels are based on the projected natural gas supply and historical liquids yields from various natural gas sources. These products move directly into the market to meet demand (e.g., for fuel or petrochemical feedstocks) or are inputs to the refinery.

Biofuels

PMM contains submodules which provide regional supplies and prices for biofuels: ethanol (conventional/corn, advanced, cellulosic) and various forms of biomass-based diesel: FAME (methyl ester), biomass-to-liquid (Fisher-Tropsch), and renewable ("green") diesel (hydrogenation of vegetable oils or fats). Ethanol is assumed to be blended either at 10 percent into gasoline (conventional or reformulated) or as E85. Food feedstock supply curves (corn, soybean oil, etc.) are updated to USDA baseline projections; biomass feedstocks are drawn from the same supply curves that also supply biomass fuel to renewable power generation within the Renewable Fuels Module of NEMS. The merchant processing units which generate the biofuels supplies sum these feedstock costs with other cost inputs (e.g., capital, operating). A major driving force behind the production of these biofuels is the Renewable Fuels Standard under EISA2007. Details on the market penetration of the advanced biofuels production capacity (such as cellulosic ethanol and BTL) which are not yet commercialized can be found in the PMM documentation.

End-Use Markups

The linear programming portion of the model provides unit prices of products sold in the refinery regions (refinery gate) and in the demand regions (wholesale). End use markups are added to produce a retail price for each of the Census Divisions. The mark ups are based on an average of historical markups, defined as the difference between the end-use prices by sector and the corresponding wholesale price for that product. The average is calculated using data from 2000 to the present. Because of the lack of any consistent trend in the historical end-use markups, the markups remain at the historical average level over the projection period.

State and Federal taxes are also added to transportation fuel prices to determine final end-use prices. Previous tax trend analysis indicates that state taxes increase at the rate of inflation, while Federal taxes do not. In PMM, therefore state taxes are held constant in real terms throughout the projection while Federal taxes are felated at the rate of inflation.[18]

Gasoline Types

Motor vehicle fuel in PMM is categorized into four gasoline blends (conventional, oxygenated conventional, reformulated, and California reformulated) and also E85. While federal law does not mandate gasoline to be oxygenated, all gasoline complying with the Federal reformulated gasoline program is assumed to contain 10 percent ethanol, while conventional gasoline may be "clear" (no ethanol) or used as E10. As the mandate for biofuels grows under the Renewable Fuels Standard, the proportion of conventional gasoline that is E10 also generally grows. California reformulated motor gasoline is assumed to contain 5.7% ethanol in 2009 and 10 percent thereafter in line with its approval of the use of California's Phase 3 reformulated gasoline.

EIA defines E85 as a gasoline type but is treated as a separate fuel in PMM. The transportation module in NEMS provides PMM with a flex fuel vehicle (FFV) demand, and PMM computes a supply curve for E85. This curve incorporates E85 infrastructure and station costs, as well as a logit relationship between the E85 station availability and demand of E85. Infrastructure costs dictate that the E85 supplies emerge in the Midwest first, followed by an expansion to the coasts.

Ultra–Low–Sulfur Diesel

By definition, Ultra Low Sulfur Diesel (ULSD) is highway diesel fuel that contains no more than 15 ppm sulfur at the pump. As of June 2006, 80 percent of all highway diesel produced or imported into the United States was required to be ULSD, while the remaining 20 percent contained a maximum of 500 parts per million. By December 1, 2010 all highway fuel sold at the pump will be required to be ULSD. Major assumptions related to the ULSD rule are as follows:

- Highway diesel at the refinery gate will contain a maximum of 7-ppm sulfur. Although sulfur content is limited to 15 ppm at the pump, there is a general consensus that refineries will need to produce diesel below 10 ppm sulfur in order to allow for contamination during the distribution process.
- Demand for highway grade diesel, both 500 and 15 ppm combined, is assumed to be equivalent to the total transportation distillate demand. Historically, highway grade diesel supplied has nearly matched total transportation distillate sales, although some highway grade

18 http://www.eia.doe.gov/oiaf/archive/aeo07/leg_reg.html.

diesel has gone to non-transportation uses such as construction and agriculture.

Gas, Coal and Biomass to Liquids

Natural gas, coal, and biomass conversion to liquid fuels is modeled in the PMM based on a three step process known as indirect liquefaction. This process is sometimes called Fischer-Tropsch (FT) liquefaction after the inventors of the second step.

The liquid fuels produced include four separate products: FT light naphtha, FT heavy naphtha, FT kerosene, and FT diesel. The FT designation is used to distinguish these liquid fuels from their petroleum counterparts. This is necessary due to the different physical and chemical properties of the FT fuels. For example, FT diesel has a typical cetane rating of approximately 70-75 while that of petroleum diesel is typically much lower (about 40). In addition, the above production methods have differing impacts with regard to current and potential legislation, particularly RFS and CO2.

Coal Market Module

Coal Market Module

The coal market module (CMM) represents the mining, transportation, and pricing of coal, subject to end-use demand. Coal supplies are differentiated by thermal grade, sulfur content, and mining method (underground and surface). CMM also determines the minimum cost pattern of coal supply to meet exogenously defined U.S. coal export demands as a part of the world coal market. Coal distribution, from supply region to demand region, is projected on a cost-minimizing basis. The domestic production and distribution of coal is projected for 14 demand regions and 14 supply regions (Figures 18 and 19).

The CMM components are solved simultaneously. The sequence of solution among components can be summarized as follows. Coal supply curves are produced by the coal production submodule and input to the coal distribution submodule. Given the coal supply curves, distribution costs, and coal demands, the coal distribution submodule projects delivered coal prices. The module is iterated to convergence with respect to equilibrium prices to all demand sectors. The structure of the CMM is shown in Figure 20.

Coal Production Submodule

This submodule produces annual coal supply curves, relating annual production to minemouth prices. The supply curves are constructed from an econometric analysis of prices as a function of productive capacity, capacity utilization, productivity, and various factor input costs. A separate supply curve is provided for surface and underground mining for all significant production by coal thermal grade (metallurgical, bituminous, subbituminous and lignite), and sulfur level in each supply region. Each supply curve is assigned a unique heat, sulfur, and mercury content, and carbon dioxide emissions factor. Constructing curves for the coal types available in each region yields a total of 40 curves that are used as inputs to the coal distribution submodule. Supply curves are updated for each year in the projection period. Coal supply curves are shared with both the EMM and the PMM. For detailed assumptions, please see the Assumptions to the Annual Energy Outlook updated each year with the release of the AEO.

Coal Distribution Submodule: Domestic Component

The coal distribution submodule is a linear program that determines the least-cost supplies of coal for a given set of coal demands by demand region and sector, accounting for transportation costs from the different supply curves, heat and sulfur content, and existing coal supply contracts. Existing supply contracts between coal producers and electricity generators are incorporated in the model as minimum flows for supply curves to coal demand regions. Depending on the specific scenario, coal distribution may also be affected by any restrictions on sulfur dioxide, mercury, or carbon dioxide emissions.

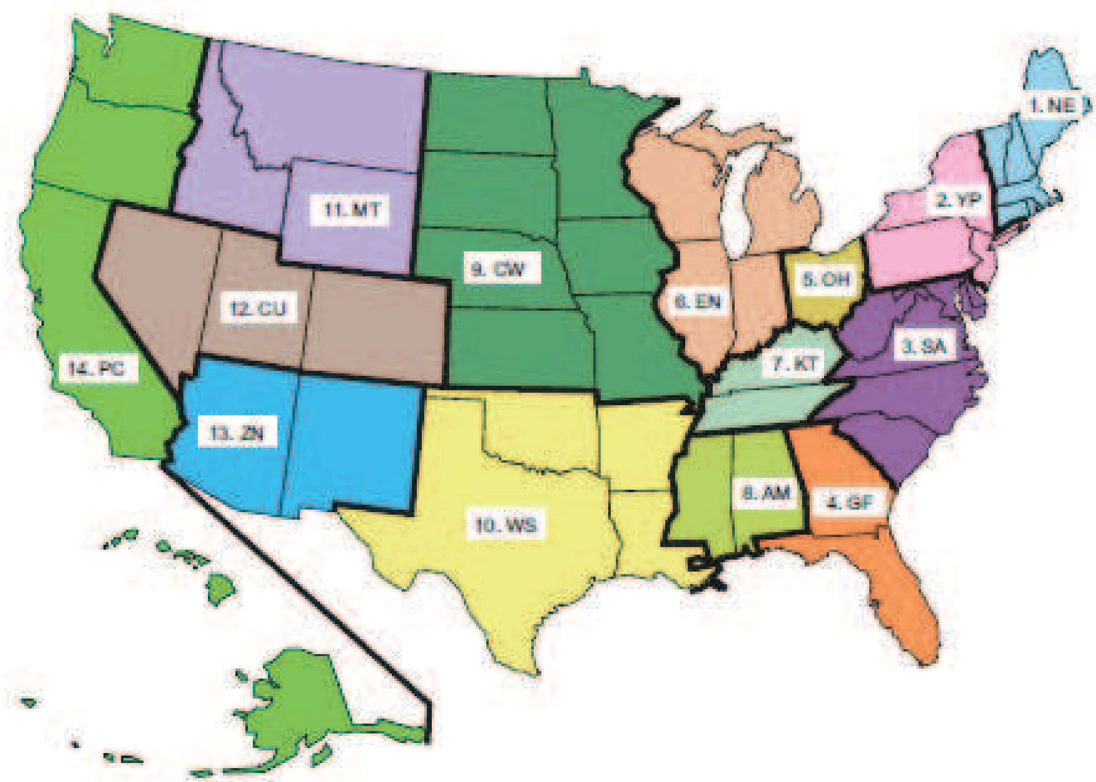
Coal transportation costs are simulated using interregional coal transportation costs derived by subtracting reported minemouth costs for each supply curve from reported delivered costs for each demand type in each demand region. For the electricity sector, higher transportation costs are assumed for market expansion in certain supply and demand region combinations. Transportation rates are modified over time using econometrically based multipliers which considers the impact of changing productivity and equipment costs. When diesel fuel prices are sufficiently high, a fuel surcharge is also added to the transportation costs.

Coal Distribution Submodule: International Component

The international component of the coal distribution submodule projects quantities of coal imported and exported from the United States. The quantities are determined within a world trade context, based on assumed characteristics of foreign coal supply and demand. The component disaggregates coal into 17 export regions and 20 import regions, as shown inTable 13. The supply and demand components of world coal trade are

CMM Outputs	Inputs from NEMS	Exogenous Inputs
Coal production and distribution Minemouth coal prices End-use coal prices U.S. coal exports and imports Transportation rates Coal quality by source, destination, and end-use sector World coal flows	Coal demand Interest rates Price indices and deflators Diesel fuel prices Electricity prices	Base year production, productive capacity, capacity utilization, prices, and coal quality parameters Contract quantities Labor productivity Labor costs Domestic transportation costs International transportation costs International supply curves International coal import demands

Figure 18. Coal Market Module Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

segmented into two separate markets: 1) coking coal, which is used for the production of coke for the steelmaking process; and 2) steam coal, which is primarily consumed in the electricity and industrial sectors.

The international component is solved as part of the linear program that optimizes U.S. coal supply. It determines world coal trade distribution by minimizing overall costs for coal, subject to coal supply prices in the United States and other coal exporting regions plus transportation costs. The component also incorporates supply diversity constraints that reflect the observed tendency of coal-importing countries to avoid excessive dependence upon one source of supply, even at a somewhat higher cost.

Coal Market Module

Figure 19. Coal Market Module Supply Regions

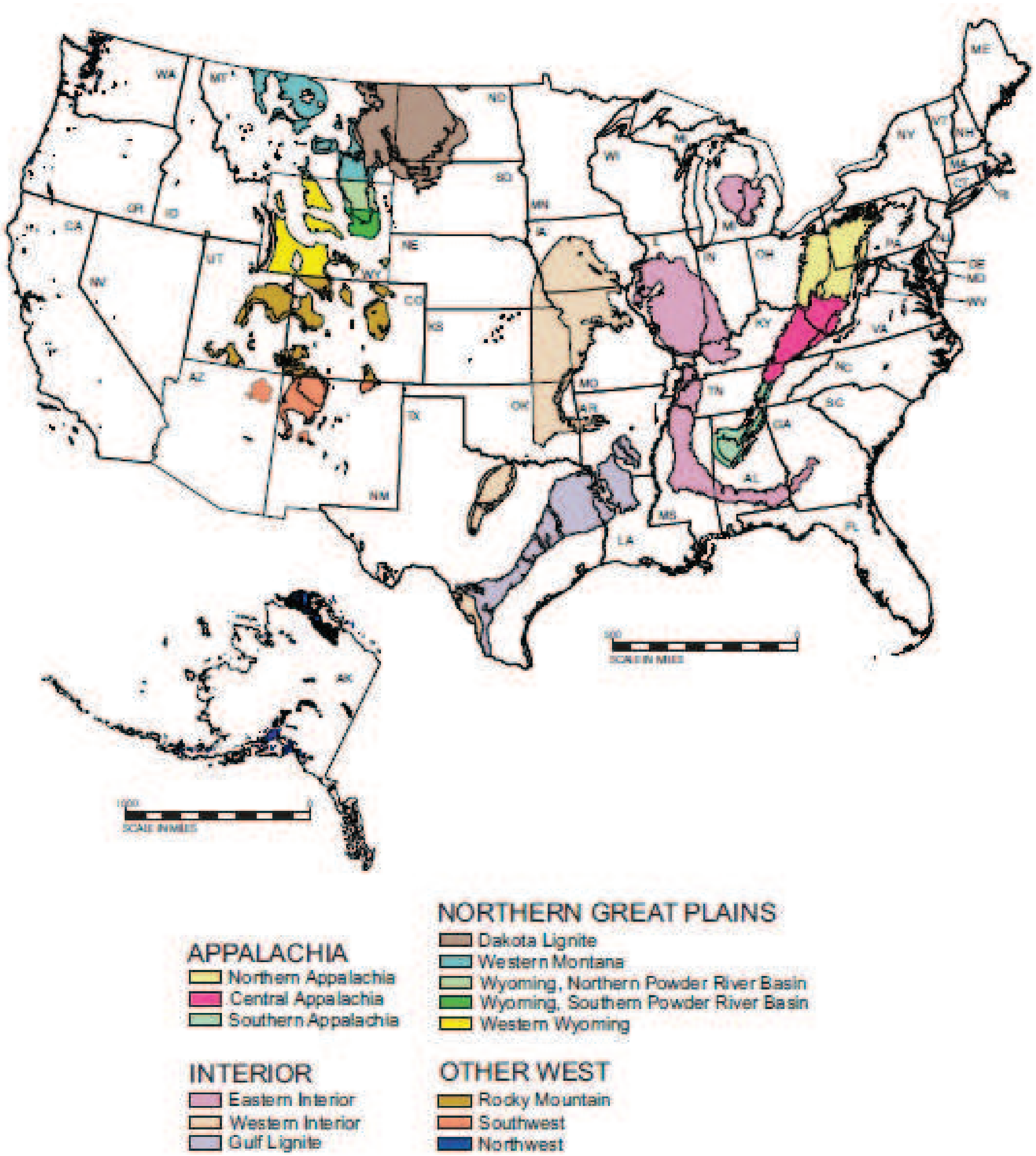
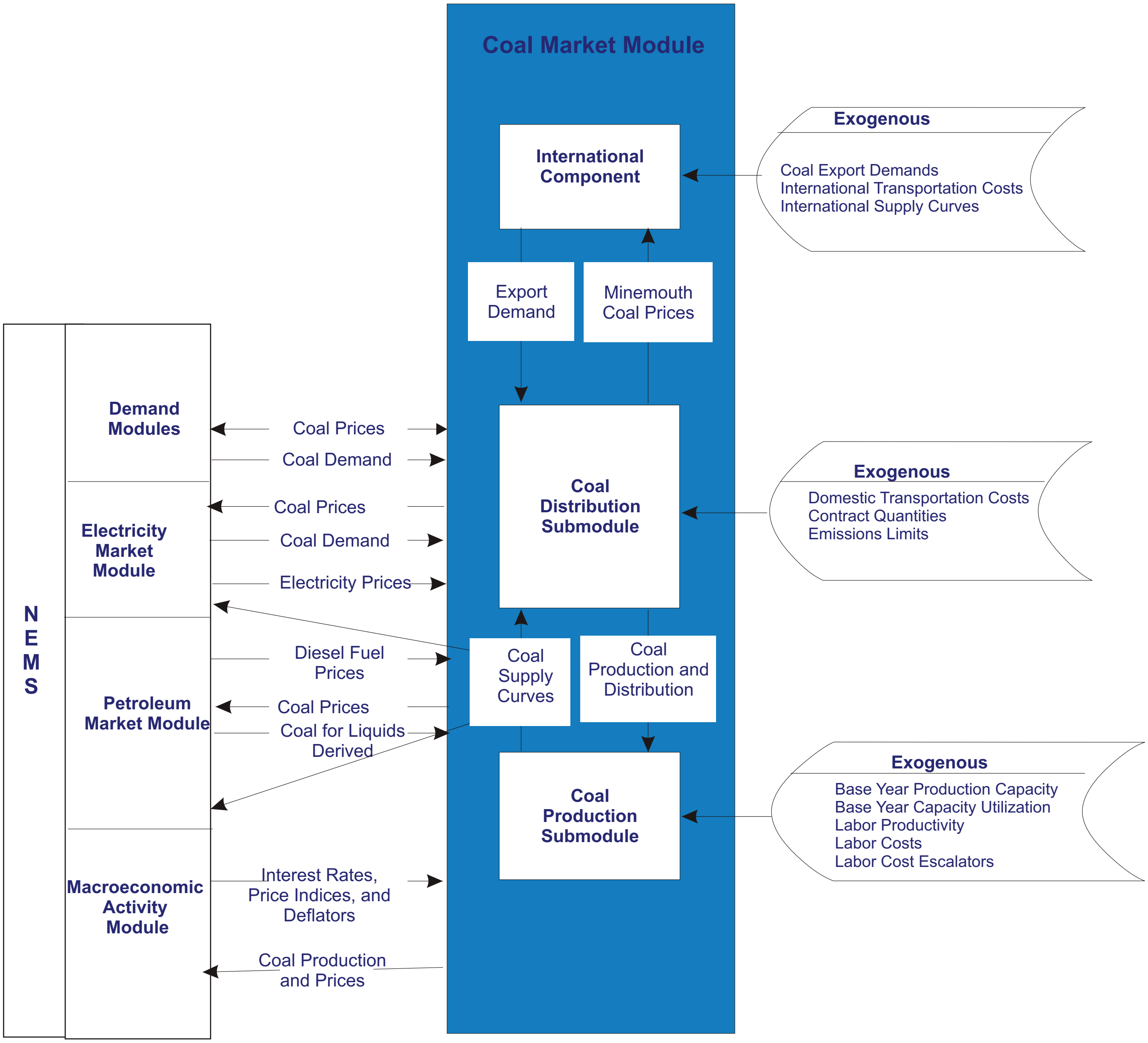


Table 13. Coal Export Component

Coal Export Regions	Coal Import Regions
U.S. East Coast	U.S. East Coast
U.S. Gulf Coast	U.S. Gulf Coast
U.S. Southwest and West	U.S. Northern Interior
U.S. Northern Interior	U.S. Noncontiguous
U.S. Noncontiguous	Eastern Canada
Australia	Interior Canada
Western Canada	Scandinavia
Interior Canada	United Kingdom and Ireland
Southern Africa	Germany and Austria
Poland	Other Northwestern Europe
Eurasia-exports to Europe	Iberia
Eurasia-exports to Asia	Italy
China	Mediterranean and Eastern Europe
Colombia	Mexico
Indonesia	South America
Venezuela	Japan
Vietnam	East Asia
	China and Hong Kong
	ASEAN (Association of Southeast Asian Nations)
	India and South Asia

Coal Market Module

Figure 20. Coal Market Module Structure



Appendix

Appendix Bibliography

The National Energy Modeling System is documented in a series of model documentation reports, available on the EIA Web site at http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model documentation or by contacting the National Energy Information Center (202/586-8800).

Energy Information Administration, *Integrating Module of the National Energy Modeling System: Model Documentation* DOE/EIA-M057(2009) (Washington, DC, May 2009).

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Energy Information Administration, *Model Documentation: Natural Gas Transmission and Distribution Model of the National Energy Modeling System*, DOE/EIA-M062(2009) (Washington, DC, June 2009).

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Energy Information Administration, *Model Documentation: Renewable Fuels Module of the National Energy Modeling System*, DOE/EIA-M069(2009) (Washington, DC, July 2009).

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DOE/EIA-M062(2011)

Model Documentation

Natural Gas Transmission and Distribution Module of the National Energy Modeling System

February 2012

Office of Petroleum, Gas, and Biofuels Analysis
U.S. Energy Information Administration
U.S. Department of Energy
Washington, DC 20585

Contact Information

The Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System is developed and maintained by the U.S. Energy Information Administration (EIA), Office of Petroleum, Gas, and Biofuels Analysis. General questions about the use of the model can be addressed to Michael Schaal (202) 586-5590, Director of the Office of Petroleum, Gas, and Biofuels Analysis. Specific questions concerning the NGTDM may be addressed to:

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This report documents the archived version of the NGTDM that was used to produce the natural gas forecasts presented in the *Annual Energy Outlook 2011*, (DOE/EIA-0383(2011). The purpose of this report is to provide a reference document for model analysts, users, and the public that defines the objectives of the model, describes its basic approach, and provides detail on the methodology employed.

The model documentation is updated annually to reflect significant model methodology and software changes that take place as the model develops. The next version of the documentation is planned to be released in the first quarter of 2012.

Update Information

This edition of the model documentation of the Natural Gas Transmission and Distribution Module (NGTDM) reflects changes made to the module over the past year for the *Annual Energy Outlook 2011*. Aside from general data and parameter updates, the notable changes include the following:

- Reestimated equations for distributor and pipeline tariffs.
- Updated coalbed and shale undiscovered resource assumptions in Canada.
- Moved representation of conventional and tight natural gas production in Western Canada from the Oil and Gas Supply Module to the NGTDM.

Contents

Tables

Figures

Abbreviations and Acronyms

AEO	Annual Energy Outlook
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
BTU	British Thermal Unit
DTS	Distributor Tariff Submodule
EMM	Electricity Market Module
GAMS	Gas Analysis Modeling System
IFFS	Integrated Future Forecasting System
ITS	Interstate Transmission Submodule
MEFS	Mid-term Energy Forecasting System
MMBTU	Million British thermal units
Mcf	Thousand cubic feet
MMcf	Million cubic feet
MMcfd	Million cubic feet per day
MMBBL	Million barrels
NEMS	National Energy Modeling System
NGA	Natural Gas Annual
NGM	Natural Gas Monthly
NGTDM	Natural Gas Transmission and Distribution Module
OGSM	Oil and Gas Supply Module
PIES	Project Independence Evaluation System
PMM	Petroleum Market Module
PTS	Pipeline Tariff Submodule
STEO	Short-Term Energy Outlook
Tcf	Trillion cubic feet
WCSB	Western Canadian Sedimentary Basin

1. Background/Overview

The Natural Gas Transmission and Distribution Module (NGTDM) is the component of the National Energy Modeling System (NEMS) that is used to represent the U.S. domestic natural gas transmission and distribution system. NEMS was developed by the former Office of Integrated Analysis and Forecasting of the U.S. Energy Information Administration (EIA) and is the third in a series of computer-based, midterm energy modeling systems used since 1974 by the EIA and its predecessor, the Federal Energy Administration, to analyze and project U.S. domestic energy-economy markets. From 1982 through 1993, the Intermediate Future Forecasting System (IFFS) was used by the EIA for its integrated analyses. Prior to 1982, the Midterm Energy Forecasting System (MEFS), an extension of the simpler Project Independence Evaluation System (PIES), was employed. NEMS was developed to enhance and update EIA's modeling capability. Greater structural detail in NEMS permits the analysis of a broader range of energy issues. While NEMS was initially developed in 1992 the model is updated each year, from simple historical data updates to complete replacements of submodules.

The time horizon of NEMS is the midterm period that extends approximately 25 years to year 2035. In order to represent the regional differences in energy markets, the component modules of NEMS function at regional levels appropriate for the markets represented, with subsequent aggregation/disaggregation to the Census Division level for reporting purposes. The projections in NEMS are developed assuming that energy markets are in equilibrium[1] using a recursive price adjustment mechanism.[2]. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for the economic competition between the various fuels and sources. NEMS is organized and implemented as a modular system.[3] The NEMS modules represent each of the fuel supply markets, conversion sectors (e.g., refineries and power generation), and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. A routine was also added to the system that simulates a carbon emissions cap and trade system with annual fees to limit carbon emissions from energy-related fuel combustion. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, Census Division, and end-use sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production activity, and international petroleum supply availability.

The integrating routine of NEMS controls the execution of each of the component modules. The modular design provides the capability to execute modules individually, thus allowing independent analysis with, as well as development of, individual modules. This modularity allows the use of the methodology and level of detail most appropriate for each energy sector. Each forecasting year, NEMS solves by iteratively calling each module in sequence (once in each NEMS iteration) until the delivered prices and quantities of each fuel in each region have

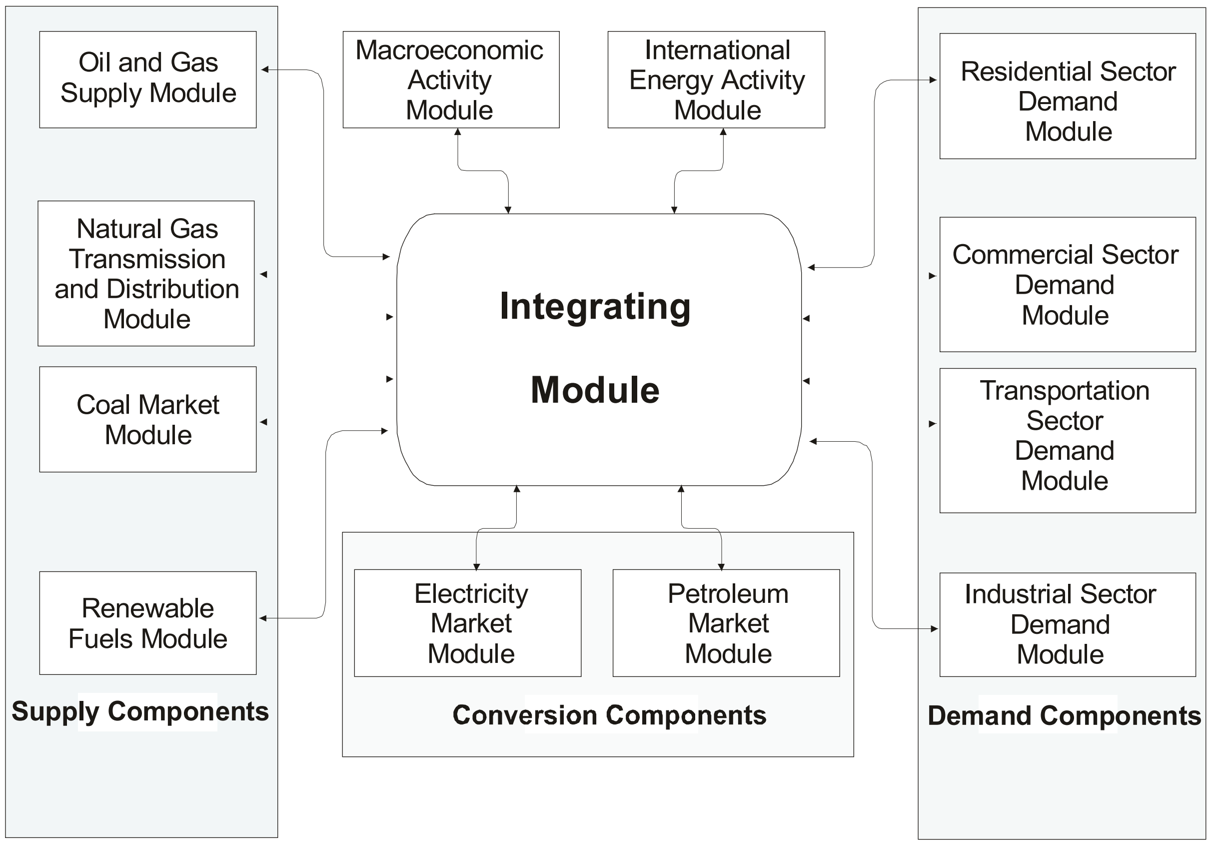
[1]Markets are said to be in equilibrium when the quantities demanded equal the quantities supplied at the same price; that is, at a price that sellers are willing to provide the commodity and consumers are willing to purchase the commodity.

[2]The central theme of the approach used is that supply and demand imbalances will eventually be rectified through an adjustment in prices that eliminates excess supply or demand.

[3]The NEMS is composed of 13 modules including a system integration routine.

converged within tolerance between the various modules, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Module solutions are reported annually through the midterm horizon. A schematic of the NEMS is provided in **Figure 1-1**, while a list of the associated model documentation reports is in Appendix C, including a report providing an overview of the whole system.

Figure 1-1. Schematic of the National Energy Modeling System



NGTDM Overview

The NGTDM module within the NEMS represents the transmission, distribution, and pricing of natural gas. Based on information received from other NEMS modules, the NGTDM also includes representations of the end-use demand for natural gas, the production of domestic natural gas, and the availability of natural gas traded on the international market. The NGTDM links natural gas suppliers (including importers) and consumers in the lower 48 States and across the Mexican and Canadian borders via a natural gas transmission and distribution network, while determining the flow of natural gas and the regional market clearing prices between suppliers and end-users. For two seasons of each forecast year, the NGTDM determines the production, flows, and prices of natural gas within an aggregate representation of the U.S./Canadian pipeline network, connecting domestic and foreign supply regions with 12 U.S. and 2 Canadian demand regions. Since the NEMS operates on an annual (not a seasonal) basis, NGTDM results are generally passed to other NEMS modules as annual totals or quantity-weighted annual averages. Since the Electricity Market Module has a seasonal component, peak and off-peak[4] prices are also provided for natural gas to electric generators.

Natural gas pricing and flow patterns are derived by obtaining a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The methodology employed allows for the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of primary pipeline and storage capacity expansion requirements. Key components of interstate pipeline tariffs are projected, along with distributor tariffs.

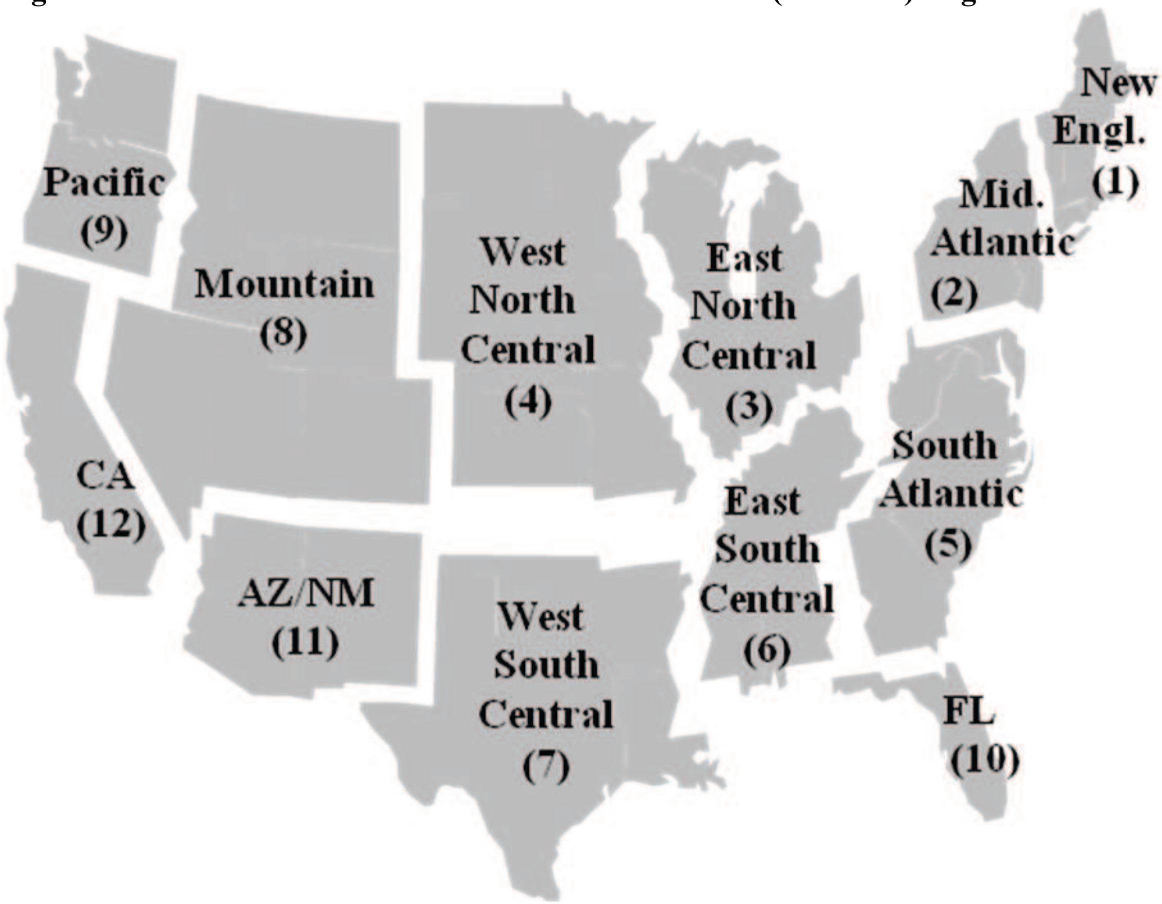
The lower-48 demand regions represented are the 12 NGTDM regions (**Figure 1-2**). These regions are an extension of the 9 Census Divisions, with Census Division 5 split into South Atlantic and Florida, Census Division 8 split into Mountain and Arizona/New Mexico, Census Division 9 split into California and Pacific, and Alaska and Hawaii handled independently. Within the U.S. regions, consumption is represented for five end-use sectors: residential, commercial, industrial, electric generation, and transportation (or natural gas vehicles), with the industrial and electric generator sectors further distinguished by core and noncore segments. One or more domestic supply region is represented in each of the 12 NGTDM regions. Canadian supply and demand are represented by two interconnected regions -- East Canada and West Canada -- which connect to the lower 48 regions via seven border crossing nodes. The demarcation of East and West Canada is at the Manitoba/Ontario border. In addition, the model accounts for the potential construction of a pipeline from Alaska to Alberta and one from the MacKenzie Delta to Alberta, if market prices are high enough to make the projects economic. The representation of the natural gas market in Canada is much less detailed than for the United States since the primary focus of the model is on the domestic U.S. market. Potential liquefied natural gas (LNG) imports into North America are modeled for each of the coastal regions represented in the model, including seven regions in the United States, a potential import point in the Bahamas, potential import points in eastern and western Canada, and in western Mexico (if destined for the United States).[5] Any LNG facilities in existence or under construction are represented in the model. However, the model does not project the construction of any additional facilities. Finally, LNG exports from Alaska's Nikiski plant are included, as well as three import/export border crossings at the Mexican border.

The module consists of three major components: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS). The ITS is the integrating submodule of the NGTDM. It simulates the natural gas price determination process by bringing together all major economic factors that influence regional natural gas trade in the United States, including pipeline and storage capacity expansion decisions. The Pipeline Tariff Submodule (PTS) generates a representation of tariffs for interstate transportation and storage services, both existing and expansions. The Distributor Tariff Submodule (DTS) generates markups for distribution services provided by local distribution companies and for

[4]The peak period covers the period from December through March; the off-peak period covers the remaining months.
[5]The LNG imports into Mexico to serve the Mexico market are set exogenously.

transmission services provided by intrastate pipeline companies. The modeling techniques employed are a heuristic/iterative process for the ITS, an accounting algorithm for the PTS, and a series of historically based and econometrically based equations for the DTS.

Figure 1-2. Natural Gas Transmission and Distribution (NGTDM) Regions



NGTDM Objectives

The purpose of the NGTDM is to derive natural gas delivered and wellhead prices, as well as flow patterns for movements of natural gas through the regional interstate network. Although the NEMS operates on an annual basis, the NGTDM was designed to be a two-season model, to better represent important features of the natural gas market. The prices and flow patterns are derived by obtaining a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The representations of the key features of the transmission and distribution network are the focus of the various components of the NGTDM. These key modeling objectives/capabilities include:

- Represent interregional flows of gas and pipeline capacity constraints
- Represent regional and import supplies
- Determine the amount and the location of required additional pipeline and storage capacity on a regional basis, capturing the economic tradeoffs between pipeline and storage capacity additions
- Provide a peak/off-peak, or seasonal analysis capability
- Represent transmission and distribution service pricing

Overview of the Documentation Report

The archived version of the NGTDM that was used to produce the natural gas forecasts used in support of the *Annual Energy Outlook 2011*, DOE/EIA-0383(2011) is documented in this report. The purpose of this report is to provide a reference document for model analysts, users, and the public that defines the objectives of the model, describes its basic design, provides detail on the methodology employed, and describes the model inputs, outputs, and key assumptions. It is intended to fulfill the legal obligation of the EIA to provide adequate documentation in support of its models (Public Law 94-385, Section 57.b.2). Subsequent chapters of this report provide:

- A description of the interface between the NEMS and the NGTDM and the representation of demand and supply used in the module (Chapter 2)
- An overview of the solution methodology of the NGTDM (Chapter 3)
- The solution methodology for the Interstate Transmission Submodule (Chapter 4)
- The solution methodology for the Distributor Tariff Submodule (Chapter 5)
- The solution methodology for the Pipeline Tariff Submodule (Chapter 6)
- A description of module assumptions, inputs, and outputs (Chapter 7).

The archived version of the model is available through the National Energy Information Center (202-586-8800, infoctr@eia.doe.gov) and is identified as NEMS2011 (part of the National Energy Modeling System archive package as archived for the Annual Energy Outlook 2011, DOE/EIA-0383(2011)).

The document includes a number of appendices to support the material presented in the main body of the report. Appendix A presents the module abstract. Appendix B lists the major references used in developing the NGTDM. Appendix C lists the various NEMS Model Documentation Reports for the various modules that are mentioned throughout the NGTDM documentation. A mapping of equations presented in the documentation to the relevant subroutine in the code is provided in Appendix D. Appendix E provides a mapping between the variables that are assigned values through READ statements in the module and the data input files that are read. The input files contain detailed descriptions of the input data, including variable names, definitions, sources, units and derivations.[6] Appendix F documents the

[6]The NGTDM data files are available upon request by contacting Joe Benneche at Joseph.Benneche@eia.doe.gov or (202) 586-6132. Alternatively an archived version of the NEMS model (source code and data files) can be downloaded from ftp://ftp.eia.doe.gov/pub/forecasts/aeo.

derivation of all empirical estimations used in the NGTDM. Variable cross-reference tables are provided in Appendix G. Finally, Appendix H contains a description of the algorithm used to project new coal-to-gas plants and the pipeline quality gas produced.

2. Demand and Supply Representation

This chapter describes how supply and demand are represented within the NGTDM and the basic role that the Natural Gas Transmission and Distribution Module (NGTDM) fulfills in the NEMS. First, a general description of the NEMS is provided, along with an overview of the NGTDM. Second, the data passed to and from the NGTDM and other NEMS modules is described along with the methodology used within the NGTDM to transform the input values prior to their use in the model. The natural gas demand representation used in the module is described, followed by a section on the natural gas supply interface and representation, and concluding with a section on the representation of demand and supply in Alaska.

A Brief Overview of NEMS and the NGTDM

The NEMS represents all of the major fuel markets (crude oil and petroleum products, natural gas, coal, electricity, and imported energy) and iteratively solves for an annual supply/demand balance for each of the nine Census Divisions, accounting for the price responsiveness in both energy production and end-use demand, and for the interfuel substitution possibilities. NEMS solves for an equilibrium in each forecast year by iteratively operating a series of fuel supply and demand modules to compute the end-use prices and consumption of the fuels represented, effectively finding the intersection of the theoretical supply and demand curves reflected in these modules.[7] The end-use demand modules (for the residential, commercial, industrial, and transportation sectors) are detailed representations of the important factors driving energy consumption in each of these sectors. Using the delivered prices of each fuel, computed by the supply modules, the demand modules evaluate the consumption of each fuel, taking into consideration the interfuel substitution possibilities, the existing stock of fuel and fuel conversion burning equipment, and the level of economic activity. Conversely, the fuel conversion and supply modules determine the end-use prices needed in order to supply the amount of fuel demanded by the customers, as determined by the demand modules. Each supply module considers the factors relevant to that particular fuel, for example: the resource base for oil and gas, the transportation costs for coal, or the refinery configurations for petroleum products. Electric generators and refineries are both suppliers and consumers of energy.

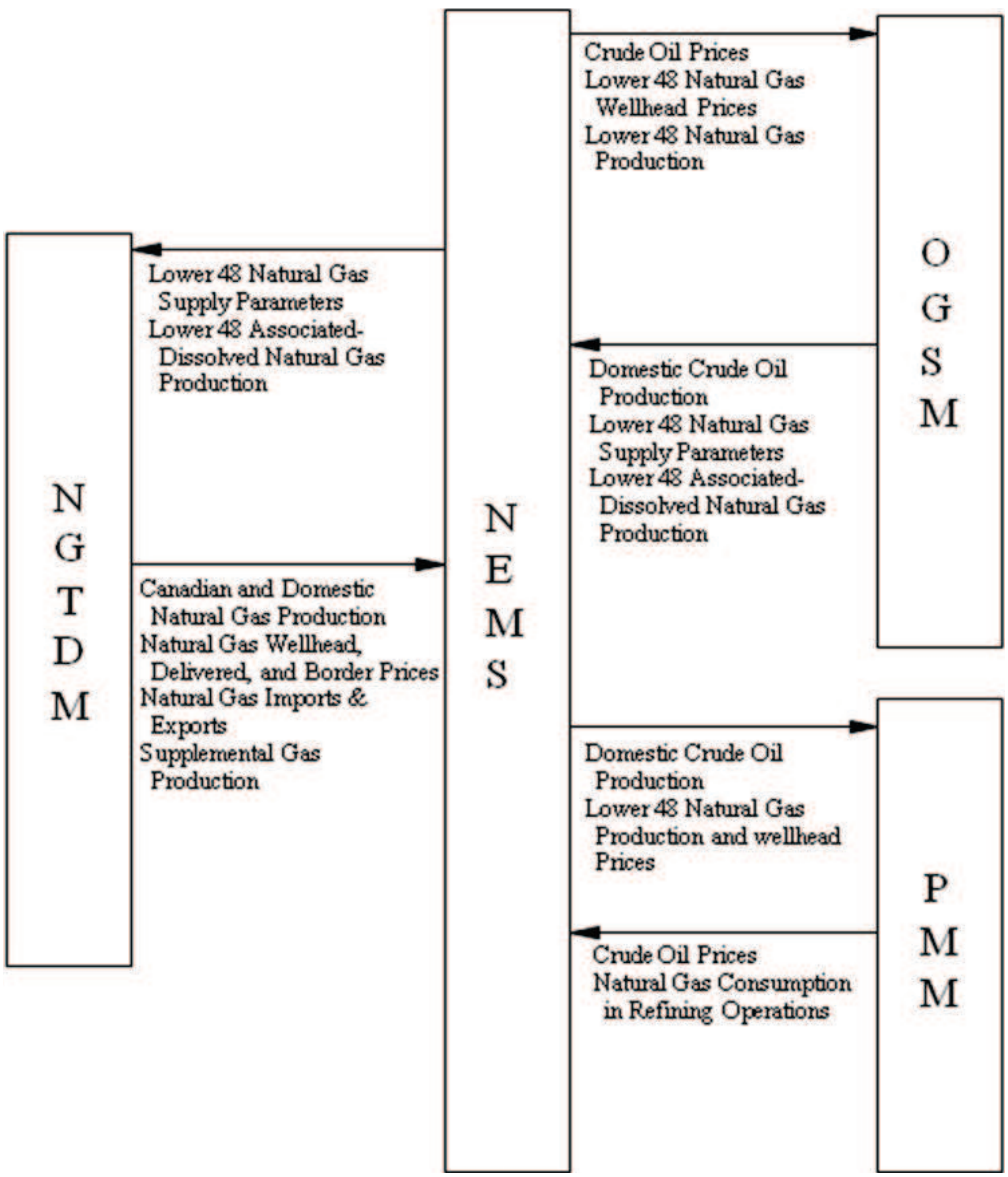
Within the NEMS system, the NGTDM provides the interface for natural gas between the Oil and Gas Supply Module (OGSM) and the demand modules in NEMS, including the Electricity Market Module (EMM). Since the other modules provide little, if any, information on markets outside of the United States, the NGTDM uses supply curves for liquefied natural gas (LNG) imports based on output results from EIA's separate International Natural Gas Model (INGM) and includes a simple representation of natural gas markets in Canada and Mexico in order to project LNG and pipeline import levels into the United States. The NGTDM estimates the price and flow of dry natural gas supplied internationally from the contiguous U.S. border[8] or

[7] A more detailed description of the NEMS system, including the convergence algorithm used, can be found in "Integrating Module of the National Energy Modeling System: Model Documentation 2010." DOE/EIA-M057(2010), May 2010 or "The National Energy Modeling System: An Overview 2009," DOE/EIA-0581(2009), October 2009.

[8] Natural gas exports are also accounted for within the model.

domestically from the wellhead (and indirectly from natural gas processing plants) to the domestic end-user. In so doing, the NGTDM models the markets for the transmission (pipeline companies) and distribution (local distribution companies) of natural gas in the contiguous United States.[9] The primary data flows between the NGTDM and the other oil and gas modules in NEMS, the Petroleum Market Module (PMM) and the OGSM are depicted in **Figure 2-1**.

Figure 2-1. Primary Data Flows between Oil and Gas Modules of NEMS



[9]Because of the distinct separation in the natural gas market between Alaska, Hawaii, and the contiguous United States, natural gas consumption in, and the associated supplies from, Alaska and Hawaii are modeled separately from the contiguous United States within the NGTDM.

In each NEMS iteration, the demand modules in NEMS provide the level of natural gas that would be consumed at the burner-tip in each region by the represented sector at the delivered price set by the NGTDM in the previous NEMS iteration. At the beginning of each forecast year during a model run, the OGSM provides an expected annual level of natural gas produced at the wellhead in each region represented, given the oil and gas wellhead prices from the previous forecast year. (Some supply sources (e.g., Canada) are modeled directly in the NGTDM.) The NGTDM uses this information to build "short-term" (annual or seasonal) supply and demand curves to approximate the supply or demand response to price. Given these short-term demand and supply curves, the NGTDM solves for the delivered, wellhead, and border prices that represent a natural gas market equilibrium, while accounting for the costs and market for transmission and distribution services (including its physical and regulatory constraints).[10] These solution prices, and associated production levels, are in turn passed to the OGSM and the demand modules, including the EMM, as primary input variables for the next NEMS iteration and/or forecast year. Most of the calculations within OGSM are performed only once each NEMS iteration, after the NEMS has converged to an equilibrium solution. Information from OGSM is passed as needed to the NGTDM to solve for the following forecast year.

The NGTDM is composed of three primary components or submodules: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS). The ITS is the central module of the NGTDM, since it is used to derive network flows and prices of natural gas in conjunction with a peak[11] and off-peak natural gas market equilibrium. Conceptually the ITS is a simplified representation of the natural gas transmission and distribution system, structured as a network composed of nodes and arcs. The other two primary components serve as satellite submodules to the ITS, providing parameters which define the tariffs to be charged along each of the interregional, intraregional, intrastate, and distribution segments. Data are also passed back to these satellite submodules from the ITS. Other parameters for defining the natural gas market (such as supply and demand curves) are derived based on information passed primarily from other NEMS modules. However in some cases, supply (e.g., synthetic gas production) and demand components (e.g., pipeline fuel) are modeled exclusively in the NGTDM.

The NGTDM is called once each NEMS iteration, but all submodules are not run for every call. The PTS is executed only once for each forecast year, on the first iteration for each year. The ITS and the DTS are executed once every NEMS iteration. The calling sequence of and the interaction among the NGTDM modules is as follows for each forecast year executed in NEMS:

First Iteration:

a. The PTS determines the revenue requirements associated with interregional / interstate pipeline company transportation and storage services, using a cost based approach, and uses this information and cost of expansion estimates as a basis in establishing fixed rates and volume dependent tariff curves (variable rates) for pipeline and storage usage.

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[10]Parameters are provided by OGSM for the construction of supply curves for domestic non-associated natural gas production. The NGTDM establishes a supply curve for conventional Western Canada. The use of demand curves in the NGTDM is an option; the model can also respond to fixed consumption levels.

[11]The peak period covers the period from December through March; the off-peak period covers the remaining months.

b. The ITS establishes supply levels (e.g., for supplemental supplies) and supply curves for production and LNG imports based on information from other modules.

Each Iteration:

a. The DTS sets markups for intrastate transmission and for distribution services using econometric relationships based on historical data, largely driven by changes in consumption levels.

b. The ITS processes consumption levels from NEMS demand modules as required, (e.g., annual consumption levels are disaggregated into peak and off-peak levels) before determining a market equilibrium solution across the two-period NGTDM network.

c. The ITS employs an iterative process to determine a market equilibrium solution which balances the supply and demand for natural gas across a U.S./Canada network, thereby setting prices throughout the system and production and import levels. This operation is performed simultaneously for both the peak and off-peak periods.

Last Iteration:

a. In the process of establishing a network/market equilibrium, the ITS also determines the associated pipeline and storage capacity expansion requirements. These expansion levels are passed to the PTS and are used in the revenue requirements calculation for the next forecast year. One of the inputs to the NGTDM is "planned" pipeline and storage expansions. These are based on reported pending and commenced construction projects and analysts' judgment as to the likelihood of the project's completion. For the first two forecast years, the model does not allow builds beyond these planned expansion levels.

b. Other outputs from NGTDM are passed to report writing routines.

For the historical years (1990 through 2009), a modified version of the above process is followed to calibrate the model to history. Most, but not all, of the model components are known for the historical years. In a few cases, historical levels are available annually, but not for the peak and off-peak periods (e.g., the interstate flow of natural gas and regional wellhead prices). The primary unknowns are pipeline and storage tariffs and market hub prices. When prices are translated from the supply nodes, through the network to the end-user (or city gate) in the historical years, the resulting prices are compared against published values for city gate prices. These differentials (benchmark factors) are carried through and applied during the forecast years as a calibration mechanism. In the most recent historical year (2009) even fewer historical values are known; and the process is adjusted accordingly.

The primary outputs from the NGTDM, which are used as input in other NEMS modules, result from establishing a natural gas market equilibrium solution: delivered prices, wellhead and border crossing prices, non-associated natural gas production, and Canadian and LNG import levels. In addition, the NGTDM provides a forecast of lease and plant fuel consumption, pipeline fuel use, as well as pipeline and distributor tariffs, pipeline and storage capacity expansion, and interregional natural gas flows.

Natural Gas Demand Representation

Natural gas produced within the United States is consumed in lease and plant operations, delivered to consumers, exported internationally, or consumed as pipeline fuel. The consumption of gas as lease, plant, and pipeline fuel is determined within the NGTDM. Gas used in well, field, and lease operations and in natural gas processing plants is set equal to a historically observed percentage of dry gas production.[12] Pipeline fuel use depends on the amount of gas flowing through each region, as described in Chapter 4. The representation in the NGTDM of gas delivered to consumers is described below.

Classification of Natural Gas Consumers

Natural gas that is delivered to consumers is represented within the NEMS at the Census Division level and by five primary end-use sectors: residential, commercial, industrial, transportation, and electric generation.[13] These demands are further distinguished by customer class (core or non-core), reflecting the type of natural gas transmission and distribution service that is assumed to be predominately purchased. A "core" customer is expected to generally require guaranteed or firm service, particularly during peak days/periods during the year. A "non-core" customer is expected to require a lower quality of transmission services (non-firm service) and therefore, consume gas under a less certain and/or less continuous basis. While customers are distinguished by customer class for the purpose of assigning different delivered prices, the NGTDM does not explicitly distinguish firm versus non-firm transmission service. Currently in NEMS, all customers in the transportation, residential, and commercial sectors are classified as core.[14] Within the industrial sector the non-core segment includes the industrial boiler market and refineries; the core makes up the rest. The electric generating units defining each of the two customer classes modeled are as follows: (1) core − gas steam units or gas combined cycle units, (2) non-core − dual-fired turbine units, gas turbine units, or dual-fired steam plants (consuming both natural gas and residual fuel oil). [15]

For any given NEMS iteration and forecast year, the demand modules in NEMS determine the level of natural gas consumption for each region and customer class given the delivered price for the same region, class, and sector, as calculated by the NGTDM in the previous NEMS iteration. Within the NGTDM, each of these consumption levels (and its associated price) is used in

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[12]The regional factors used in calculating lease and plant fuel consumption (PCTLP) are initially based on historical averages (1996 through 2009) and held constant throughout the forecast period. However, a model option allows for these factors to be scaled in the first one or two forecast years so that the resulting national lease and plant fuel consumption will match the annual published values presented in the latest available *Short-Term Energy Outlook* (STEO), DOE/EIA-0202), (Appendix E, STQLPIN). The adjustment attributable to benchmarking to STEO (if selected as an option) is phased out by the year STPHAS_YR (Appendix E). For *AEO2011* these factors were phased out by 2014. A similar adjustment is performed on the factors used in calculating pipeline fuel consumption using STEO values from STQGPTR (Appendix E).

[13]Natural gas burned in the transportation sector is defined as compressed natural gas or liquefied natural gas that is burned in natural gas vehicles; and the electric generation sector includes all electric power generators whose primary business is to sell electricity, or electricity and heat, to the public, including combined heat and power plants, small power producers, and exempt wholesale generators.

[14]The NEMS is structurally able to classify a segment of these sectors as non-core, but currently sets the non-core consumption at zero for the residential, commercial, and transportation sectors.

[15]Currently natural gas prices for the core and non-core segments of the electric generation sector are set to the same average value.

conjunction with an assumed price elasticity as a basis for building an annual demand curve. [The price elasticities are set to zero if fixed consumption levels are to be used.] These curves are used within the NGTDM to minimize the required number of NEMS iterations by approximating the demand response to a different price. In so doing, the price where the implied market equilibrium would be realized can be approximated. Each of these market equilibrium prices is passed to the appropriate demand module during the next NEMS iteration to determine the consumption level that the module would actually forecast at this price. Once the NEMS converges, the difference between the actual consumption, as determined by the NEMS demand modules, and the approximated consumption levels in the NGTDM are insignificant.

For all but the electric sector, the NGTDM disaggregates the annual Census division regional consumption levels into the regional and seasonal representation that the NGTDM requires. The regional representation for the electric generation sector differs from the other NEMS sectors as described below.

Regional/Seasonal Representations of Demand

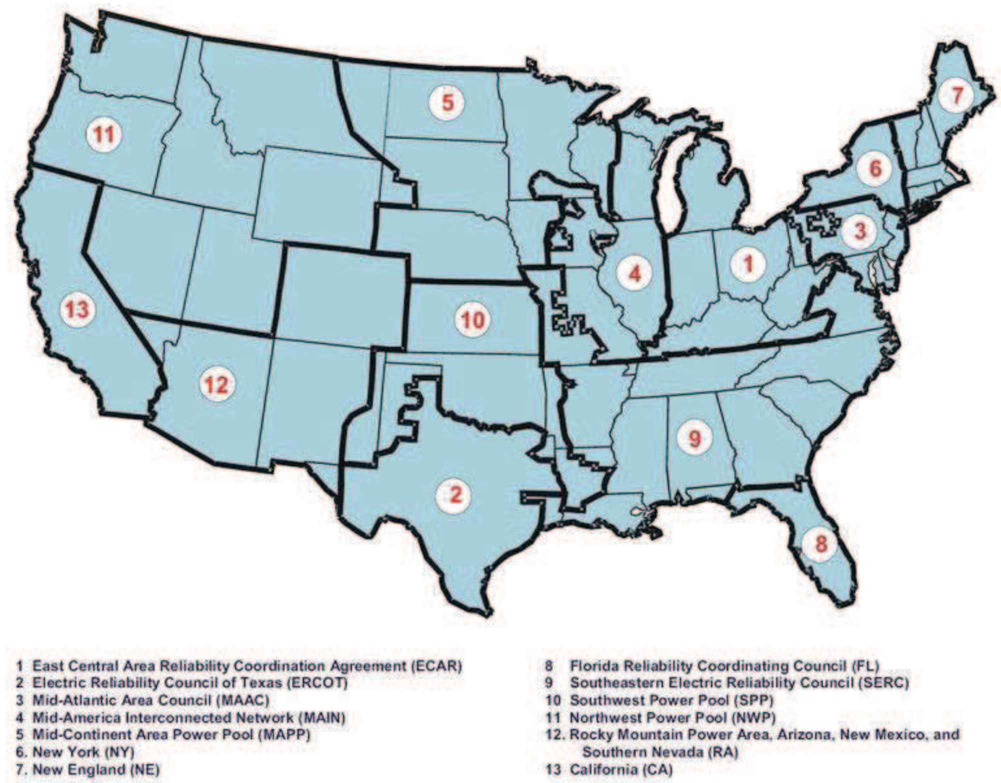
Natural gas consumption levels by all non-electric[16] sectors are provided by the NEMS demand modules for the nine Census divisions, the primary integrating regions represented in the NEMS. Alaska and Hawaii are included within the Pacific Census Division. The EMM represents the electricity generation process for 13 electricity supply regions, the nine North American Electric Reliability Council (NERC) Regions and four selected NERC Subregions (**Figure 2-2**). Within the EMM, the electric generators' consumption of natural gas is disaggregated into subregions that can be aggregated into Census Divisions or into the regions used in the NGTDM.

With the few following exceptions, the regional detail provided at a Census division level is adequate to build a simple network representative of the contiguous U.S. natural gas pipeline system. First, Alaska is not connected to the rest of the Nation by pipeline and is therefore treated separately from the contiguous Pacific Division in the NGTDM. Second, Florida receives its gas from a distinctly different route than the rest of the South Atlantic Division and is therefore isolated. A similar statement applies to Arizona and New Mexico relative to the Mountain Division. Finally, California is split off from the contiguous Pacific Division because of its relative size coupled with its unique energy related regulations. The resulting 12 primary regions represented in the NGTDM are referred to as the "NGTDM Regions" (as shown in **Figure 1-2**).

The regions represented in the EMM do not always align with State borders and generally do not share common borders with the Census divisions or NGTDM regions. Therefore, demand in the electric generation sector is represented in the NGTDM at a seventeen subregional (NGTDM/EMM) level which allows for a reasonable regional mapping between the EMM and the NGTDM regions (**Figure 2-3**). The seventeenth region is Alaska. Within the EMM, the disaggregation into subregions is based on the relative geographic location (and natural gas-fired generation capacity) of the current and proposed electricity generation plants within each region.

[16]The term "non-electric" sectors refer to sectors (other than commercial and industrial combined heat and power generators) that do not produce electricity using natural gas (i.e., the residential, commercial, industrial, and transportation demand sectors).

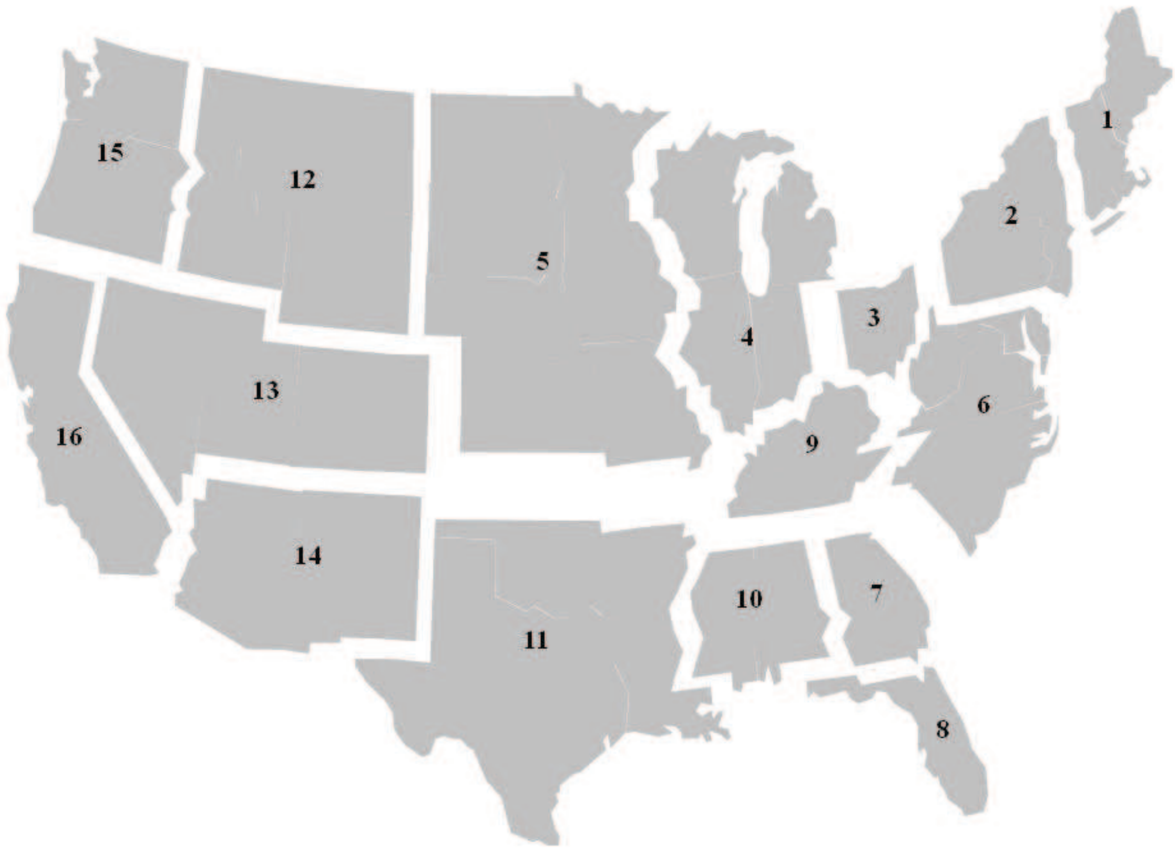
Figure 2-2. Electricity Market Module (EMM) Regions



Annual consumption levels for each of the non-electric sectors are disaggregated from the nine Census divisions to the two seasonal periods and the twelve NGTDM regions by applying average historical shares (2001 to 2009) that are held constant throughout the forecast (census − NG_CENSHR, seasons − PKSHR_DMD). For the Pacific Division, natural gas consumption estimates for Alaska are first subtracted to establish a consumption level for just the contiguous Pacific Division before the historical share is applied. The consumption of gas in Hawaii was considered to be negligible and is not handled separately. Within the NGTDM, a relatively simple series of equations (described later in the chapter) was included for approximating the consumption of natural gas by each non-electric sector in Alaska. These estimates, combined with the levels provided by the EMM for consumption by electric generators in Alaska, are used in the calculation of the production of natural gas in Alaska.

Unlike the non-electric sectors, the factors (core − PKSHR_UDMD_F, non-core − PKSHR_UDMD_I) for disaggregating the annual electric generator sector consumption levels (for each NGTDM/EMM region and customer type − core and non-core) into seasons are adjusted over the forecast period. Initially average historical shares (1994 to 2009, except New England − 1997 to 2009) are established as base level shares (core − BASN_PKSHR_UF,

Figure 2-3. NGTDM/EMM Regions



non-core − BASN_PKSHR_UI). The peak period shares are increased each year of the forecast by 0.5 percent (with a corresponding decrease in the off-peak shares) not to exceed 32 percent of the year.[17]

Natural Gas Demand Curves

While the primary analysis of energy demand takes place in the NEMS demand modules, the NGTDM itself directly incorporates price responsive demand curves to speed the overall convergence of NEMS and to improve the quality of the results obtained when the NGTDM is run as a stand-alone model. The NGTDM may also be executed to determine delivered prices for fixed consumption levels (represented by setting the price elasticity of demand in the demand curve equation to zero). The intent is to capture relatively minor movements in consumption levels from the provided base levels in response to price changes, not to accurately mimic the expected response of the NEMS demand modules. The form of the demand curves for the firm transmission service type for each non-electric sector and region is:

[17] The peak period covers 33 percent of the year.

$$NGDMD\_CRVF_{s,r} = BASQTY\_F_{s,r} * (PR / BASPR\_F_{s,r})^{NONU\_ELAS\_F_s} \quad (1)$$

where,

$BASPR\_F_{s,r}$	=	delivered price to core sector s in NGTDM region r in the previous NEMS iteration (1987 dollars per Mcf)
$BASQTY\_F_{s,r}$	=	natural gas quantity which the NEMS demand modules indicate would be consumed at price BASPR_F by core sector s in NGTDM region r (Bcf)
$NONU\_ELAS\_F_s$	=	short-term price elasticity of demand for core sector s (set to zero for *AEO2011* or to represent fixed consumption levels)
PR	=	delivered price at which demand is to be evaluated (1987 dollars per Mcf)
$NGDMD\_CRVF_{s,r}$	=	estimate of the natural gas which would be consumed by core sector s in region r at the price PR (Bcf)
s	=	core sector (1-residential, 2-commercial, 3-industrial, 4-transportation)

The form of the demand curve for the non-electric interruptible transmission service type is identical, with the following variables substituted: NGDMD_CRVI, BASPR_I, BASQTY_I, and NONU_ELAS_I (all set to zero for *AEO2011*). For the electric generation sector the form is identical as well, except there is no sector index and the regions represent the 16 NGTDM/EMM lower 48 regions, not the 12 NGTDM regions. The corresponding set of variables for the core and non-core electric generator demand curves are [NGUDMD_CRVF, BASUPR_F, BASUQTY_F, UTIL_ELAS_F] and [NGUDMD_CRVI, BASUPR_I, BASUQTY_I, UTIL_ELAS_I], respectively. For the *AEO2011* all of the electric generator demand curve elasticities were set to zero.

Domestic Natural Gas Supply Interface and Representation

The primary categories of natural gas supply represented in the NGTDM are non-associated and associated-dissolved gas from onshore and offshore U.S. regions; pipeline imports from Mexico; Eastern, Western (conventional and unconventional), and Arctic Canada production; LNG imports; natural gas production in Alaska (including that which is transported through Canada via pipeline[18]); synthetic natural gas produced from coal and from liquid hydrocarbons; and other supplemental supplies. Outside of Alaska (which is discussed in a later section) the only supply categories from this list that are allowed to vary within the NGTDM in response to a change in the current year's natural gas price are the non-associated gas from onshore and offshore U.S. regions, conventional gas from the Western Canada region, and LNG imports.[19]

[18] Several different options have been proposed for bringing stranded natural gas in Alaska to market (i.e., by pipeline, as LNG, and as liquids). Previously, the LNG option was deemed the least likely and is not considered in this version of the model, but will be reassessed in the future. The Petroleum Market Module forecasts the potential conversion of Alaska natural gas into liquids. The NGTDM allows for the building of a generic pipeline from Alaska into Alberta, although not at the same time as a MacKenzie Valley pipeline. The pipeline is assumed to have first access to the currently proved reserves in Alaska which are assumed to be producible at a relatively low cost given their association with oil production.

[19] Liquefied natural gas imports are set based on the price in the previous NEMS iteration and are effectively "fixed" when the NGTDM determines a natural gas market equilibrium solution; whereas the other two categories are determined as a part of the

The supply levels for the remaining categories are fixed at the beginning of each forecast year (i.e., before market clearing prices are determined), with the exception of associated-dissolved gas (determined in OGSM).[20] With the exception of LNG, the NGTDM applies average historical relationships to convert annual "fixed" supply levels to peak and off-peak values. These factors are held constant throughout the forecast period.

Within the OGSM, natural gas supply activities are modeled for 12 U.S. supply regions (6 onshore, 3 offshore, and 3 Alaskan geographic areas). The six onshore OGSM regions within the contiguous United States, shown in **Figure 2-4**, do not generally share common borders with the NGTDM regions. The NGTDM represents onshore supply for the 17 regions resulting from overlapping the OGSM and NGTDM regions (**Figure 2-5**). A separate component of the NGTDM models the foreign sources of gas that are transported via pipeline from Canada and Mexico. Seven Canadian and three Mexican border crossings demarcate the foreign pipeline interface in the NGTDM. Potential LNG imports are represented at each of the coastal NGTDM regions; however, import volumes will only be projected based on where existing or exogenously set additional regasification capacity exists (e.g., if a facility is under construction or deemed highly likely to be constructed).[21]

"Variable" Dry Natural Gas Production Supply Curve

The two "variable" (or price responsive) natural gas supply categories represented in the model are domestic non-associated production and total production from the Western Canadian Sedimentary Basin (WCSB). Non-associated natural gas is largely defined as gas that is produced from gas wells, and is assumed to vary in response to a change in the natural gas price. Associated-dissolved gas is defined as gas that is produced from oil wells and can be classified as a byproduct in the oil production process. Each domestic supply curve is defined through its associated parameters as being net of lease and plant fuel consumption (i.e., the amount of dry gas available for market after any necessary processing and before being transported via pipeline). For both of these categories, the supply curve represents annual production levels. The methodology for translating this annual form into a seasonal representation is presented in Chapter 4.

The supply curve for regional non-associated lower 48 natural gas production and for WCSB production is built from a price/quantity (P/Q) pair, where quantity is the "expected" production (XQBASE) or the base production level as defined by the product of reserves times the "expected" production-to-reserves ratio (as set in the OGSM) and price is the projected wellhead price (XPBASE, presented below) for the expected production. The basic assumption behind the curve is that the realized market price will increase from the base price if the current year's production levels exceed the expected production; and the opposite will occur if current production is less In addition, it is assumed that the relative price response will likely be greater for a marginal increase in production above the expected production, compared to below. To

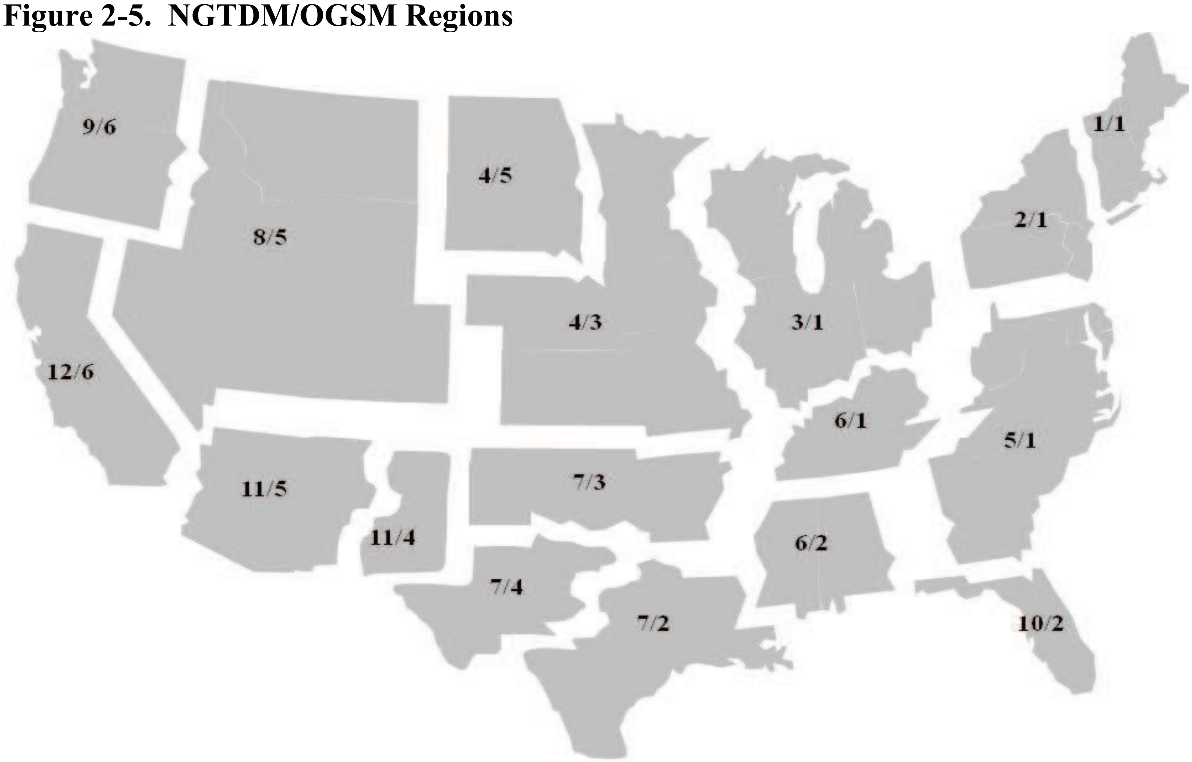
market equilibrium process in the NGTDM.

[20]For programming convenience natural gas produced with oil shales (OGSHALENG) is also added to this category.

[21]Structurally an LNG regasification terminal in the Bahamas would be represented as entering into Florida and be reported as pipeline imports, although modeled as LNG imports. No regasification terminals are considered for Alaska or Hawaii.

Figure 2-4. Oil and Gas Supply Module (OGSM) Regions

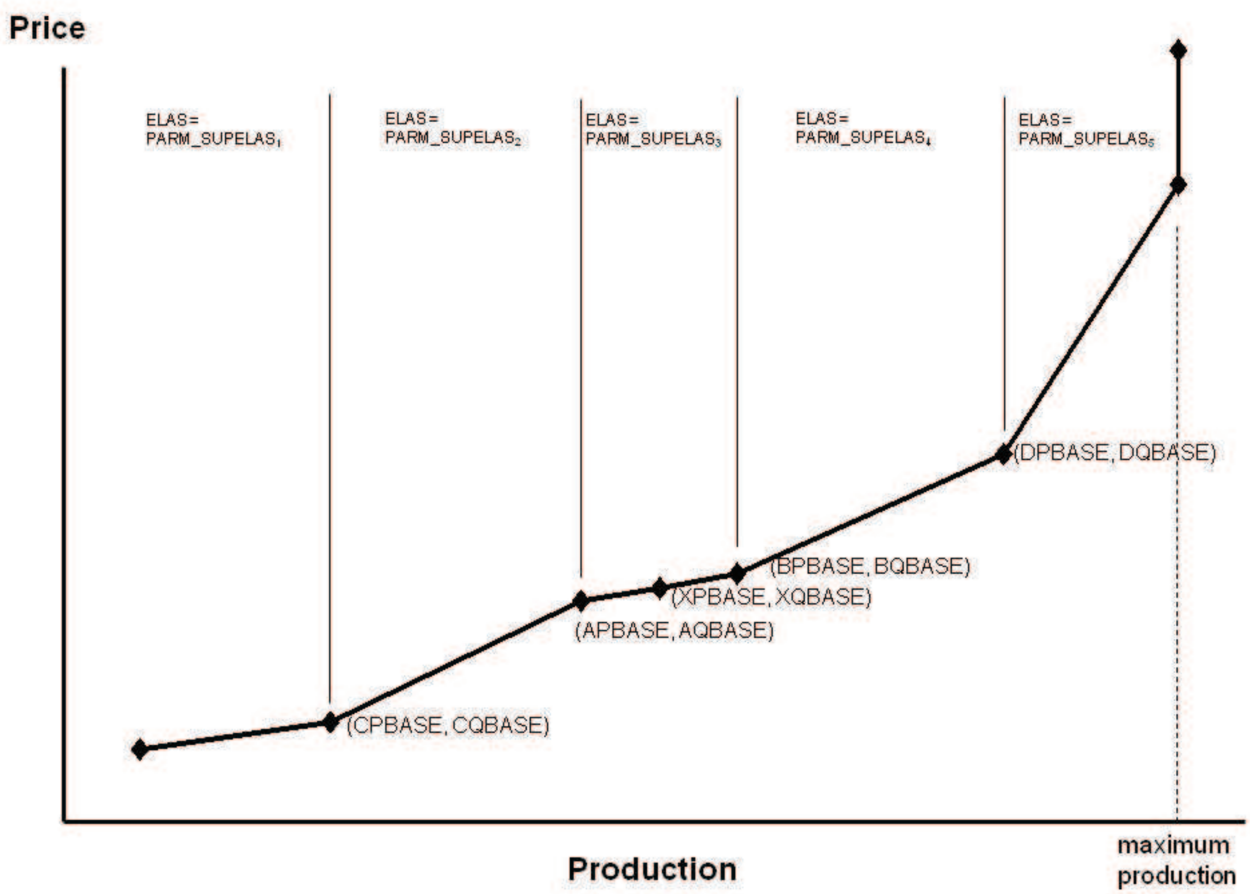
Figure 2-5. NGTDM/OGSM Regions



NGTDM Region Number / OGSM Region Number represent these assumptions, five segments of the curve are defined from the base point. The middle segment is centered around the base point, extends plus or minus a percent (PARM_SUPCRV3, Appendix E) from the base quantity, and if activated, is generally set nearly horizontal (i.e., there is little price response to a quantity change). The next two segments, on either side of the middle, extend more vertically (with a positive slope), and reach plus or minus a percent (PARM_SUPCRV5, Appendix E) beyond the end of the middle segment. The remaining two segments extend the curve above and below even further for the case with relatively large annual production changes, and can be assigned the same or different slopes from their adjacent segments. The slope of the upper segment(s) is generally set greater than or equal to that of the lower segment(s). An illustrative presentation of the supply curve is provided in **Figure 2-6**. The general structure for all five segments of the supply curve, in terms of defining price (NGSUP_PR) as a function of the quantity or production level (QVAR), is:

$$NGSUP\_PR = PBASE * (((\frac{1}{ELAS}) * (\frac{QVAR - QBASE}{QBASE})) + 1) \quad (2)$$

Figure 2-6. Generic Supply Curve



A more familiar form of this equation is the definition of elasticity (ξ) as: $\xi = (\Delta Q/Q_o) / (\Delta P/P_o)$, where Δ symbolizes "the change in" and Q_o and P_o represent a base level price/quantity pair.

Each of the five segments is assigned different values for the variables ELAS, PBASE, and QBASE:

Lowest segment:

$$\begin{aligned} PBASE = CPBASE = APBASE * (1 - \\ (PARM\_SUPCRV5/PARM\_SUPELAS2) \end{aligned} \quad (3)$$

$$QBASE = CQBASE = AQBASE * (1 - PARM\_SUPCRV5) \quad (4)$$

$$ELAS = PARM\_SUPELAS1 = 0.40 \quad (5)$$

Lower segment:

$$\begin{aligned} PBASE = APBASE = XPBASE * \\ (1 - (PARM\_SUPCRV3/PARM\_SUPELAS3)) \end{aligned} \quad (6)$$

$$QBASE = AQBASE = XQBASE * (1 - PARM\_SUPCRV3) \quad (7)$$

$$ELAS = PARM\_SUPELAS2 = 0.35 \quad (8)$$

Middle segment:
(in historical years)

$$PBASE = XPBASE = \text{historical wellhead price} \quad (9)$$

$$QBASE = XQBASE = QSUP_s/(1 - PERCNT_n) \quad (10)$$

(in forecast years)

$$PBASE = XPBASE = ZWPRLAG_s \quad (11)$$

$$QBASE = XQBASE = ZOGRESNG_s * ZOGPRRNG_s \quad (12)$$

$$ELAS = PARM\_SUPELAS3 = 1.00 \quad (13)$$

Upper segment:

$$\begin{aligned} PBASE = BPBASE = XPBASE * \\ (1 + (PARM\_SUPCRV3/PARM\_SUPELAS3)) \end{aligned} \quad (14)$$

$$QBASE = BQBASE = XQBASE * (1 + PARM\_SUPCRV3) \quad (15)$$

$$ELAS = PARM\_SUPELAS4 = 0.25 \quad (16)$$

Uppermost segment:

$$PBASE = DPBASE = BPBASE * (1 + (PARM\_SUPCRV5/PARM\_SUPELAS4)) \quad (17)$$

$$QBASE = DQBASE = BQBASE * (1 + PARM\_SUPCRV5) \quad (18)$$

$$ELAS = PARM\_SUPELAS5 = 0.20 \quad (19)$$

where,

NGSUP_PR	=	Wellhead price (1987$/Mcf)
QVAR	=	Production, including lease & plant (Bcf)
XPBASE	=	Base wellhead price on the supply curve (1987$/Mcf)
XQBASE	=	Base wellhead production on the supply curve (Bcf)
PBASE	=	Base wellhead price on a supply curve segment (1987$/Mcf)
QBASE	=	Base wellhead production on a supply curve segment (Bcf)
AQBASE, BQBASE, CQBASE, DQBASE	=	Production levels defining the supply curve in Figure 2-6 (Bcf)
APBASE, BPBASE, CPBASE, DPBASE	=	Price levels defining the supply curve in Figure 2-6 (Bcf)
ELAS	=	Elasticity (percent change in quantity over percent change in price) (analyst judgment)
PARM_SUPCRV3	=	(defined in preceding paragraph)
PARM_SUPCRV5	=	(defined in preceding paragraph)
PARM_SUPELAS#	=	Elasticity (percentage change in quantity over percentage change in price) on different segments (#) of supply curve
$ZWPRLAG_s$	=	Lagged (last year's) wellhead price for supply source s (1987/Mcf)
$ZOGRESNG_s$	=	Natural gas proved reserves for supply source s at the beginning of the year (Bcf)
$ZOGPRRNG_s$	=	Natural gas production to reserves ratio for supply sources (fraction)
$PERCNT_n$	=	Percent lease and plant
s	=	supply source
n	=	region/node
t	=	year

The parameters above will be set depending on the location of QVAR relative to the base quantity (XQBASE) (i.e., on which segment of the curve that QVAR falls). In the above equation, the QVAR variable includes lease and plant fuel consumption. Since the ITM domestic production quantity (VALUE) represents supply levels net of lease and plant, this value must be adjusted once it is sent to the supply curve function, and before it can be evaluated, to generate a corresponding supply price. The adjustment equation is:

$$QVAR = (VALUE - FIXSUP) / (1.0 - PERCNT_n)$$

$$[\text{where,} \quad FIXSUP = ZOGCCAPPRD_s * (1.0 - PERCNT_n)]$$

where,

QVAR	=	Production, including lease and plant consumption
VALUE	=	Production, net of lease and plant consumption

$PERCNT_n$ = Percent lease and plant consumption in region/node n (set to PCTLP, set to zero for Canada)
$ZOGCCAPPRD_s$ = Coalbed gas production related to the Climate Change Action Plan (from OGSM)[22]
FIXSUP = ZOGCCAPPRD net of lease and plant consumption
s = NGTDM/OGSM supply region
n = region/node

Associated-Dissolved Natural Gas Production

Associated-dissolved natural gas refers to the natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved). The production of associated-dissolved natural gas is tied directly with the production (and price) of crude oil. The OGSM projects the level of associated-dissolved natural gas production and the results are passed to the NGTDM for each iteration and forecast year of the NEMS. Within the NGTDM, associated-dissolved natural gas production is considered "fixed" for a given forecast year and is split into peak and off-peak values based on average (1994-2009) historical shares of total (including non-associated) peak production in the year (PKSHR_PROD).

Supplemental Gas Sources

Existing sources for synthetically produced pipeline-quality, natural gas and other supplemental supplies are assumed to continue to produce at historical levels. While the NGTDM has an algorithm (see Appendix H) to project potential new coal-to-gas plants and their gas production, the annual production of synthetic natural gas from coal at the existing plant is exogenously specified (Appendix E, SNGCOAL), independent of the price of natural gas in the current forecast year. The *AEO2011* forecast assumes that the sole existing plant (the Great Plains Coal Gasification Plant in North Dakota) will continue to operate at recent historical levels indefinitely. Regional forecast values for other supplemental supplies (SNGOTH) are set at historical averages (2003 to 2008) and held constant over the forecast period. Synthetic natural gas is no longer produced from liquid hydrocarbons in the continental United States; although small amounts were produced in Illinois in some historical years. This production level (SNGLIQ) is set to zero for the forecast. The small amount produced in Hawaii is accounted for in the output reports (set to the historical average from 1997 to 2008). If the option is set for the first two forecast years of the model to be calibrated to the *Short Term Energy Outlook (STEO)* forecast, then these three categories of supplemental gas are similarly scaled so that their sum will equal the national annual forecast for total supplemental supplies published in the *STEO* (Appendix E, STOGPRSUP). To guarantee a smooth transition, the scaling factor in the last STEO year can be progressively phased out over the first STPHAS_YR (Appendix E) forecast years of the NGTDM. Regional peak and off-peak supply levels for the three supplemental gas supplies are generated by applying the same average (1990-2009) historical share (PKSHR_SUPLM) of national supplemental supplies in the peak period.

[22]This special production category is not included in the reserves and production-to-reserve ratios calculated in the OGSM, so it was necessary to account for it separately when relevant. It is no longer relevant and is set to zero.

Natural Gas Imports and Exports Interface and Representation

The NGTDM sets the parameters for projecting gas imported through LNG facilities, the parameters and forecast values associated with the Canada gas market, and the projected values for imports from and exports to Mexico.

Canada

A node for east and west Canada is included in the NGTDM equilibration network, as well as seven border crossings. The model includes a representation/accounting of the U.S. border crossing pipeline capacity, east and west seasonal storage transfers, east and west consumption, east and west LNG imports (described in a later section), eastern production, conventional/tight sands production in the west, and coalbed/shale production. The ultimate determination of the import volumes into the United States occurs in the equilibration process of the NGTDM.

Base level consumption of natural gas in Eastern and Western Canada (Appendix E, CN_DMD), including gas used in lease, plant, and pipeline operations, is set exogenously,[23] and ultimately split into seasonal periods using PKSHR_CDMD (Appendix E). The projected level of oil produced from oil sands is also set exogenously to the NGTDM (based on the same source) and varies depending on the world oil price case. Starting in a recent historical year (Appendix E, YDCL_GASREQ), the natural gas required to support the oil sands production is set at an assumed ratio (Appendix E, INIT_GASREQ) of the oil sands production. Over the projection period this ratio is assumed to decline with technological improvements and as other fuel options become viable. The applied ratio in year t is set by multiplying the initially assumed rate by $(t-YDCL\_GASREQ+1)^{DECL\_GASREQ}$, where DECL_GASREQ is assumed based on anecdotal information (Appendix E). The oil sands related gas consumption under reference case world oil prices is subtracted from the base level total consumption and the remaining volumes are adjusted slightly based on differences in the world oil price in the model run versus the world oil price used in setting the base level consumption, using an assumed elasticity (Appendix E, CONNOL_ELAS). Finally, total consumption is set to this adjusted value plus the calculated gas consumed for oil sands production under the world oil price case selected. Oil sands production is assumed to just occur in Western Canada.

Currently, the NGTDM exogenously sets a forecast of the physical capacity of natural gas pipelines crossing at seven border points from Canada into the United States (excluding any expansion related to the building of an Alaska pipeline). This option can also be used within the model, if border crossing capacity is set endogenously, to establish a minimum pipeline build level (Appendix E, ACTPCAP and PLANPCAP). The model allows for an endogenous setting of annual Canadian pipeline expansion at each Canada/U.S. border crossing point based on the annual growth rate of consumption in the U.S. market it predominately serves. The resulting physical capacity limit is then multiplied by a set of exogenously specified maximum utilization rates for each seasonal period to establish maximum effective capacity limits for these pipelines (Appendix E, PKUTZ and OPUTZ). “Effective capacity” is defined as the maximum seasonal,

[23]se values were based on projections taken from the *International Energy Outlook 2010*.

physically sustainable, capacity of a pipeline times the assumed maximum utilization rate. It should be noted that some of the natural gas on these lines passes through the United States only temporarily before reentering Canada, and therefore is not classified as imports.[24] If a decision is made to construct a pipeline from Alaska (or the MacKenzie Delta) to Alberta, the import pipeline capacity added from the time the decision is made until the pipeline is in service is tracked. This amount is subtracted from the size of the pipeline to Alberta to arrive at an approximation for the amount of additional import capacity that will be needed to bring the Alaska or MacKenzie[25] gas to the United States. This total volume is apportioned to the pipeline capacity at the western import border crossings according to their relative size at the time.

Conventional Western Canada

The vast majority of natural gas produced in Canada currently is from the WCSB. Therefore, a different approach was used in modeling supplies from this region. The model consists of a series of estimated and reserves accounting equations for forecasting conventional (including from tight formations)[26] wells drilled, reserves added, reserve levels, and expected production-to-reserve ratios in the WCSB. Drilling activity, measured as the number of successful natural gas wells drilled, is estimated directly as a function of various market drivers rather than as a function of expected profitability. No distinction is made between wells for exploration and development. Next, an econometrically specified finding rate is applied to the successful wells to determine reserve additions; a reserves accounting procedure yields reserve estimates (beginning of year reserves). Finally an estimated extraction rate determines production potential [production-to-reserves ratio (PRR)].

Wells Determination

The total number of successful conventional natural gas wells drilled in Western Canada each year is forecasted econometrically as a function of the Canadian natural gas wellhead price, remaining undiscovered resources, last year's production-to-reserve ratio, and a proxy term for the drilling cost per well, as follows:

$$\begin{aligned} SUCWELL_t &= \exp(-1.85639) * CN\_PRC00_t^{1.09939} * URRCAN_t^{1.57373} \\ &\quad * CST\_PRXYLAG^{-0.86063} * \exp(33.6237 * CURPRRCAN_{t-1}) \end{aligned} \tag{20}$$

where,

[24] A significant amount of natural gas flows into Minnesota from Canada on an annual basis only to be routed back to Canada through Michigan. The levels of gas in this category are specified exogenously (Appendix E, FLOW_THRU_IN) and split into peak and off-peak levels based on average (1990-2009 historically based shares for general Canadian imports (PKSHR_ICAN).

[25] All of the gas from the MacKenzie Delta is not necessarily targeted for the U.S. market directly. Although it is anticipated that the additional supply in the Canadian system will reduce prices and increase the demand for Canadian gas in the United States. The methodology for representing natural gas production in the MacKenzie Delta and the associated pipeline is described in the section titled "Alaskan Natural Gas Routine."

[26] Since current data tend to combine statistics for drilling and production from conventional sources and that from tight gas formations, the model does not distinguish the two at present. The conventional resource estimate was increased by 1.5 percent per year as a rough estimate of the future contribution from resource appreciation and from tight formations until more reliable estimates can be generated. For the rest of the discussion on Canada, the use of the term "conventional" should be assumed to include gas from tight formations.

$SUCWELL_t$ = total conventional successful gas wells completed in Western Canada in year t

CN_PRC00_t = average Western Canada wellhead price per Mcf of natural gas in 2000 US dollars in year t

$URRCAN_t$ = remaining conventional undiscovered recoverable gas resources in the beginning of year t in Western Canada in (Bcf), specified below

CST_PRXYLAG = proxy term to reflect the change in drilling costs per well, projected into the future based on projections for the average lower 48 drilling costs the previous forecast year

CURPRRCAN = expected production-to-reserve ratio from the previous forecast year, specified below

Parameter values and details about the estimation of this equation can be found in Table F11 of Appendix F. The number of wells is restricted to increase by no more than 30 percent annually.

Reserve Additions

The reserve additions algorithm calculates units of gas added to Western Canadian Sedimentary Basin proved reserves. The methodology for conversion of gas resources into proved reserves is a critically important aspect of supply modeling. The actual process through which gas becomes proved reserves is a highly complex one. This section presents a methodology that is representative of the major phases that occur; although, by necessity, it is a simplification from a highly complex reality.

Gas reserve additions are calculated using a finding rate equation. Typical finding rate equations relate reserves added to 1) wells or feet drilled in such a way that reserve additions per well decline as more wells are drilled, and/or 2) remaining resources in such a way that reserve additions per well decline as remaining resources deplete. The reason for this is, all else being equal, the larger prospects typically are drilled first. Consequently, the finding rate can be expected to decline as a region matures, although the rate of decline and the functional forms are a subject of considerable debate. In previous versions of the model the finding rate (reserves added per well) was assumption based, while the current version is econometrically estimated using the following:

$$\begin{aligned} FRCAN_t = \exp\{(1-0.428588)*-25.3204\} * URRCAN_t^{2.13897} * \\ FRLAG^{0.428588} * URRCAN_{t-1}^{--0.428588*2.13897}] \end{aligned} \qquad (21)$$

where,

$FRCAN_t$ = finding rate in year t (Bcf per well)

FRLAG = finding rate in year t-1 (Bcf per well)

$URRCAN_t$ = remaining conventional gas recoverable resources in year t in Western Canada in (Bcf)

Parameter values and details about the estimation of this equation can be found in Table F12 of Appendix F. Remaining conventional plus tight gas recoverable resources are initialized in 2004 and set each year thereafter as follows:

$$URRCAN_t = RESBASE * (1 + RESTECH)^T - CUMRCAN \tag{22}$$

where,

RESBASE	=	initial recoverable resources in 2004 (set at 92,800 Bcf) [27]
RESTECH	=	assumed rate of increase, primarily due to the contribution from tight gas formations, but also attributable to technological improvement (1.5 percent or 0.015)
$CUMRCAN_t$	=	cumulative reserves added since initial year of 2004 in Bcf
T	=	the forecast year (t) minus the base year of 2004.

Total reserve additions in period t are given by:

$$RESADCAN_t = FRCAN_t * SUCWELL_t \tag{23}$$

where,

$RESADCAN_t$	=	reserve additions in year t, in BCF
$FRCAN_{t-1}$	=	finding rate in the previous year, in BCF per well
$SUCWELL_t$	=	successful gas wells drilled in year t

Total end-of-year proved reserves for each period equal proved reserves from the previous period plus new reserve additions less production.

$$RESBOYCAN_{t+1} = CURRESCAN_t + RESADCAN_t - OGPRDCAN_t \tag{24}$$

where,

$RESBOYCAN_{t+1}$	=	beginning of year reserves for year t+1, in BCF
$CURRESCAN_t$	=	beginning of year reserves for t, in BCF
$RESADCAN_t$	=	reserve additions in year t, in BCF
$OGPRDCAN_t$	=	production in year t, in BCF
t	=	forecast year

When rapid and slow technological progress cases are run, the forecasted values for the number of successful wells and for the expected production-to-reserve ratio for new wells are adjusted accordingly.

Gas Production

Production is commonly modeled using a production-to-reserves ratio. A major advantage to this approach is its transparency. Additionally, the performance of this function in the aggregate is

[27] Source: National Energy Board, "Canada's Conventional Natural Gas Resources: A Status Report," Table 1.1A, April 2004.

consistent with its application on the micro level. The production-to-reserves ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves.

Conventional gas production in the WCSB in year t is determined in the NGTDM through a market equilibrium mechanism using a supply curve based on an expected production level provided by the OGSM. The realized extraction is likely to be different. The expected or normal operating level of production is set as the product of the beginning-of-year reserves (RESBOYCAN) and an expected extraction rate under normal operating conditions. This expected production-to-reserve ratio is estimated as follows:

$$PRRATCAN_t = \frac{e^{-72.1364+0.117911*\ln SUCWELL_t+0.041469*\ln FRCAN_t+0.03437*RLYR}}{1+e^{-72.1364+0.117911*\ln SUCWEL_t+0.041469*\ln FRCAN_t+0.03437*RLYR}} * \left(\frac{PRRATCAN_{t-1}}{1-PRRATCAN_{t-1}}\right)^{0.916835} * e^{-0.916835*(-72.1364+0.117911*\ln SUCWELL_{t-1}+0.041469*\ln FRCAN_{t-1}+0.03437*(RLYR-1))} \quad (25)$$

where,

$PRRATCAN_t$	=	expected production-to-reserve natural gas ratio in Western Canada for conventional and tight gas
$FRCAN_t$	=	finding rate in year t, in BCF per well
$SUCWELL_t$	=	successful gas wells drilled in year t
RLYR	=	calendar year

Parameter values and details about the estimation of this equation can be found in Table F13 of Appendix F. The resulting production-to-reserve ratio is limited, so as not to increase or decrease more than 5 percent from one year to the next and to stay within the range of 0.7 to 0.12.

The potential or expected production level is used within the NGTDM to build a supply curve for conventional and tight natural gas production in Western Canada. The form of this supply curve is effectively the same as the one used to represent non-associated natural gas production in lower 48 regions. This curve is described later in this chapter, with the exceptions related to Canada noted. A primary difference is that the supply curve for the lower 48 States represents non-associated natural gas production net of lease and plant fuel consumption; whereas the Western Canada supply curve represents total conventional and tight natural gas production inclusive of lease and plant fuel consumption.

Canada Shale and Coalbed

Natural gas produced from other unconventional sources (coal beds and shale) in Western Canada (PRD2) is based on an assumed production profile, with the area under the curve equal to the assumed ultimate recovery (CUR_ULTRES). The production level is initially specified in terms of the forecast year and is set using one functional form before reaching its peak production level and a second functional form after reaching its peak production level. Before reaching peak production, the production levels are assumed to follow a quadratic form, where the level of production is zero in the first year (LSTYR0) and reaches its peak level (PKPRD) in the peak year (PKIYR). The area under the assumed production function equals the assumed technically recoverable resource level (CUR_ULTRES) times the assumed percentage (PERRES) produced before hitting the peak level. After peak production the production path is assumed to decline linearly to the last year (LSTYR) when production is again zero. The two curves meet in the peak year (PKIYR) when both have a value equal to the peak production level (PKPRD). The actual production volumes are adjusted to reflect assumed technological improvement and by a factor that depends on the difference between an assumed price trajectory and the actual price projected in the model. The specifics follow:

Before Peak Production

Assumptions:

production function

$$PRD2 = PARMA*(PRDIYR - PKIYR)^2 + PARMB \tag{26}$$

area under the production function

$$CUR\_ULTRES * PERRES$$

$$\int_{LSTYR0}^{PKIYR} [PARMA * (PRDIYR - PKIYR)^2 + PARMB]\, dPRDIYR \tag{27}$$

production in year LSTYR0:

$$0 = PARMA*(LSTYR0 - PKIYR)^2 + PARMB \tag{28}$$

production in peak year when PRDIYR = PKIYR

$$PKPRD = PARMA*(PKIYR - PKIYR)^2 + PARMB = PARMB \tag{29}$$

Derived from above:

$$PARMA = \frac{-3}{2} * \frac{CUR\_ULTRES * PERRES}{(PKIYR - LSTYRO)^3} \tag{30}$$

$$PARMB = -PARMA*(LSTYRO - PKIYR)^2 \tag{31}$$

After Peak Production

Assumptions:

production function

$$PRD2 = (PARMC*PRDIYR) + PARMD \tag{32}$$

area under the production function

$$CUR\_ULTRES*(1 - PERRES) = \int_{PKIYR}^{LSTYR} [(PARMC* PRDIYR) + PARMD]\, dPRDIYR \tag{33}$$

production in peak year when PRDIYR = PKIYR

$$PKPRD = PARMB = (PARMC^* PKIYR) + PARMD \tag{34}$$

production in last year LSTYR

$$0 = (PARMC^*LSTYR) + PARMD \tag{35}$$

Derived from above:

$$PARMC = \frac{-PARMB^2}{2^*CUR\_ULTRES^*(1-PERRES)} \tag{36}$$

$$LSTYR = \frac{2^*CUR\_ULTRES^*(1-PERRES)}{PARMB} + PKIYR \tag{37}$$

$$PARMD = -PARMC^*LSTYR \tag{38}$$

given,

$$CUR\_ULTRES = ULTRES^*(1+RESTECH)^{(MODYR-RESBASE)} {}^*(1+RESADJ) \tag{39}$$

and,

PRD2	=	Unadjusted Canada unconventional gas production (Bcf)
PKPRD	=	Peak production level in year PKIYR
CUR_ULTRES	=	Estimate of ultimate recovery of natural gas from unconventional Canada sources in the current forecast year (Bcf)
ULTRES	=	Estimate of ultimate recovery of natural gas from unconventional Canada sources in the year RESBASE (8,000 Bcf for coalbed in 2008 and 153,000 Bcf for shale in 2011, based on assumed resource levels used in EIA's International Natural Gas Model for the *International Energy Outlook 2010*.
RESBASE	=	Year associated with CUR_ULTRES
RESTECH	=	Technology factor to increase resource estimate over time (1.0)
MODYR	=	Current forecast year
RESADJ	=	Scenario specific resource adjustment factor (default value of 0.0)
PERRES	=	Percent of ultimate resource produced before the peak year of production (0.50, fraction)
PKIYR	=	Assumed peak year of production (2045)
LSTYR0	=	Last year of zero production (2004)
PRDIYR	=	Implied year of production along cumulative production path after price adjustment

The actual production is set by taking the unadjusted unconventional gas production (PRD2) and multiplying it by a price adjustment factor, as well as a technology factor. The price adjustment factor (PRCADJ) is based on the degree to which the actual price in the previous forecast year compares against a prespecified expected price path (exprc), represented by the functional form: exprc = (2.0 + [0.08*(MODYR-2008)]. The price adjustment factor is set to the price in the previous forecast year divided by the expected price, all raised to the 0.1 power. Technology is assumed to progressively increase production by 1 percent per year (TECHGRW) more than it would have been otherwise (e.g., in the fifth forecast year production is increased by 5 percent above what it would have been otherwise). [28] Once the production is established for a given forecast year, the value of PRDIYR is adjusted to reflect the actual production in the previous year and incremented by 1 for the next forecast year.

The remaining forecast elements used in representing the Canada gas market are set exogenously in the NGTDM. When required, such annual forecasts are split into peak and off-peak values using historically based or assumed peak shares that are held constant throughout the forecast. For example, the level of natural gas exports (Appendix E, CANEXP) are currently set exogenously to NEMS, are distinguished by seven Canada/U.S. border crossings, and are split between peak and off-peak periods by applying average (1992 to 2009, Appendix E, PKSHR_ECAN) historical shares to the assumed annual levels. While most Canadian import levels into the U.S. are set endogenously, the flow from Eastern Canada into the East North Central region is secondary to the flow going in the opposite direction and is therefore set exogenously (Appendix E, Q23TO3). “Fixed” supply values for the entire Eastern Canada region are set exogenously (Appendix E, CN_FIXSUP)[29] and split into peak and off-peak periods using PKSHR_PROD (Appendix E).

Mexico

The Mexico model is largely based on exogenously specified assumptions about consumption and production growth rates and LNG import levels. For the most part, natural gas imports from Mexico are set exogenously for each of the three border crossing points with the United States, with the exception of any gas that is imported into Baja, Mexico, in liquid form only to be exported to the United States. Exports to Mexico from the United States are established before the NGTDM equilibrates and represents the required level to balance the assumed consumption in (and exports from) Mexico against domestic production and LNG imports. The supply levels are also largely assumption based, but are set to vary to a degree with changes in the expected wellhead price in the United States. Peak and off-peak values for imports from and exports to Mexico are based on average historical shares (1994 or 1991 to 2009, PKSHR_IMEX and PKSHR_EMEX, respectively).

Mexican gas trade is a complex issue, as a range of non-economic factors will influence, if not determine, future flows of gas between the United States and Mexico. Uncertainty surrounding Mexican/U.S. trade is great enough that not only is the magnitude of flow for any future year in doubt, but also the direction of net flows. Despite the uncertainty and the significant influence of non-economic factors that influence Mexican gas trade with the United States, a methodology to anticipate the path of future Mexican imports from, and exports to, the United States has been incorporated into the NGTDM. This outlook is generated using assumptions regarding regional supply from indigenous production and/or liquefied natural gas (LNG) and regional/sectoral demand growth for natural gas in Mexico.

[28] If a rapid or slow technology case is being run, this value is increased or decreased accordingly.

[29] Eastern Canada is expected to continue to provide only a small share of the total production in Canada and is almost exclusively offshore.

Assumptions for the growth rate of consumption (Appendix E, PEMEX_GFAC, IND_GFAC, ELE_GFAC, RC_GFAC) were based on the projections from the *International Energy Outlook 2010*. Assumptions about base level domestic production (PRD_GFAC) are based in part on the same source and analyst judgment. The production growth rate is adjusted using an additive factor based on the degree to which the average lower 48 wellhead price varies from a set base price, as follows:

$$\text{PRC\_FAC} = MIN\left\{\left(\frac{OGWPRNG}{3.66}\right)^{0.03125} - 1, \quad 0.05\right\} \tag{40}$$

where,

PRC_FAC	=	Factor to add to assumed base level production growth rate (PRD_GFAC)
OGWPRNG	=	Lower 48 average natural gas wellhead price in the current forecast year (1987$/Mcf)
3.66	=	Fixed base price, approximately equal to the average lower 48 natural gas wellhead price over the projection period based on *AEO2010* reference case results (1987$/Mcf), [set in the code and converted at $6.14 (2008$/Mcf)]
0.03125	=	An assumed parameter
0.05	=	Assumed minimum price factor

The volumes of LNG imported into Mexico for use in the country are initially set exogenously (Appendix E, MEXLNG). However, these values are scaled back if the projected total volumes available to North America (see below) are not sufficient to accommodate these levels. LNG imports into Baja destined for the U.S. are set endogenously with the LNG import volumes for the rest of North America, as discussed below. Finally, any excess supply in Mexico is assumed to be available for export to the United States, and any shortfall is assumed to be met by imports from the United States. [30]

Liquefied Natural Gas

LNG imports are set at the beginning of each NEMS iteration within the NGTDM by evaluating seasonal supply curves, based on outputs from EIA's International Natural Gas Model (INGM), at associated regasification tailgate prices set in the previous NEMS iteration. LNG exports from the lower 48 States are assumed to be zero for the forecast period. [31] LNG exports to Japan from Alaska are set exogenously by OGSM through Spring of 2013 when the Kenai Peninsula LNG plant's export license will expire. The NGTDM does not assume or project additional LNG exports from Alaska.[32] LNG import levels are established for each region, and period (peak and

[30]A minimum import level from Mexico is set exogenously (DEXP_FRMEX, Appendix E), as well as a maximum decline from historical levels for exports to Mexico (DFAC_TOMEX, Appendix E).

[31]The capability to project LNG exports in the model was not included in the *AEO2011* analysis largely due to resource constraints, which continue to be tight. While a very preliminary analysis was done using the International Natural Gas Model that showed the economic viability of a liquefaction project in the Gulf of Mexico to be questionable under preliminary reference case conditions, a more thorough analysis is warranted.

[32]TransCanada and ExxonMobil filed an open season plan for an Alaska Pipeline Project which includes an option for shipping

off-peak) The basic process is as follows for each NEMS iteration (except for the first step): 1) at the beginning of each forecast year set up LNG supply curves for eastern and western North America for each period (peak and off-peak), 2) using the supply curves and the quantity-weighted average regasification tailgate price from the previous NEMS iteration, determine the amount of LNG available for import into North America, 3) subtract the volumes that are exogenously set and dedicated to the Mexico market (unless they exceed the total), and 4) allocate the remaining amount to the associated LNG terminals using a share based on the regasification capacity, the volumes imported last year, and the relative prices.

The LNG import supply curves are developed off of a base price/quantity pair (Appendix E, LNGPPT, LNGQPT) from a reference case run of the INGM, using the same, or very similar, world oil price assumptions. The quantities equal the sum of the LNG imports into east or west North America in the associated period; and the prices equal the quantity-weighted average tailgate price at the regasification terminals. The mathematical specification of the curve is exactly like the one used for domestic production described earlier in this chapter, except the assumed elasticities are represented with different variables and have different values.[33] This representation represents a first cut at integrating the information from INGM in the domestic projections.[34] The formulation for these LNG supply curves will likely be revised in future NEMS to better capture the market dynamics as represented in the INGM.

Once the North American LNG import volumes are established, the exogenously specified LNG imports into Mexico are subtracted,[35] along with the sum of any assumed minimum level (Appendix E, LNGMIN) for each of the representative terminals in the U.S., Canada, and Baja, Mexico (as shown in **Table 2-1**). The remainder (TOTQ) is shared out to the terminals and then added to the terminal's assumed minimum import level to arrive at the final LNG import level by terminal and season. The shares are initially set as follows and then normalized to total to 1.0:

$$LSHR_{n,r} = \left\{ \frac{QLNGLAG_{n,r} - (LNGMIN_r * SH_{r,n})}{TOTQ_{n,c}} * PERQ + \frac{LNGCAP_r - LNGMIN_r}{TOTCAP_c} * (1 - PERQ) \right\} * \left\{ \frac{PLNG_{n,r}}{AVGPR_{n,c}} \right\}^{BETA} \tag{41}$$

where,

$LSHR_{n,r}$	=	Initial share (before normalization) of LNG imports going to terminal r in period n from the east or west coast, fraction
$TOTQ_{n,c}$	=	The level of LNG imports in the east or west coast to be shared out for a period n to the associated U.S. regasification regions

gas to Valdez for export as LNG. Previous EIA analysis indicated that the option for a pipeline to the lower 48 States is likely to provide a greater netback to the producers and is therefore a more viable option. This analysis and model assumption will be reviewed in the future.

[33]For LNG the variables are called PARM_LNGxx, instead of PARM_SUPxx and are also traceable using Appendix E.

[34]As first implemented, the resulting LNG import volumes were somewhat erratic, so a five-year moving average was applied to the quantity inputs to smooth out the trajectory and more closely approximate a trend line.

[35]If the total available LNG import levels exceed the assumed LNG imports into Mexico, the volumes into Mexico are adjusted accordingly, not to be set below assumed minimums (Appendix E, MEXLNGMIN).

$QLNGLAG_{n,r}$ = LNG import level last year (Bcf)
$LNGMIN_r$ = Minimum annual LNG import level (Bcf) (Appendix E)
$SH_{r,n}$ = Fraction of LNG imported in period n last year
$LNGCAP_r$ = Beginning of year LNG sendout capacity[36] (Bcf) (Appendix E)
$TOTCAP_c$ = Total LNG sendout capacity on the east or west coast (Bcf)
PERQ = Assumed parameter (0.5)
$PLNG_{n,r}$ = Regasification tailgate price (1987$/Mcf)
$AVGPR_{n,r}$ = Average regasification tailgate price on the east or west coast (1987$/Mcf)
BETA = Assumed parameter (1.2)
r = Regasification terminal number (See Table 2-1)
n = Network or period (peak or off-peak)
c = East or west coast

Table 2-1. LNG Regasification Regions

Number	Regasification Terminal/Region	Number	Regasification Regions
1	Everett, MA	9	Alabama/Mississippi
2	Cove Point, MD	10	Louisiana/Texas
3	Elba Island, GA	11	California
4	Lake Charles, LA	12	Washington/Oregon
5	New England	13	Eastern Canada
6	Middle Atlantic	14	Western Canada
7	South Atlantic	15	Baja into the U.S.
8	Florida/Bahamas	--	--

Source: Office of Integrated Analysis and Forecasting, U.S. Energy Information Administration

Alaska Natural Gas Routine

The NEMS demand modules provide a forecast of natural gas consumption for the total Pacific Census Division, which includes Alaska. Currently natural gas that is produced in Alaska cannot be transported to the lower 48 States via pipeline. Therefore, the production and consumption of natural gas in Alaska is handled separately within the NGTDM from the contiguous States. Annual estimates of contiguous Pacific Division consumption levels are derived within the NGTDM by first estimating Alaska natural gas consumption for all sectors, and then subtracting these from the core market consumption levels in the Pacific Division provided by the NEMS demand modules. The use of natural gas in compressed natural gas vehicles in Alaska is assumed to be negligible or nonexistent. The Electricity Market Module provides a value for

[36]Send-out capacity is the maximum annual volume of gas that can be delivered by a regasification facility into the pipeline.

natural gas consumption in Alaska by electric generators. The series of equations for specifying the consumption of gas by Alaska residential and commercial customers follows:

$$AK\_RN_y = \exp\{-2.677 + (0.888 * \ln(AK\_RN_{y-1})) - (0.185 * \ln(AK\_RN_{y-2})) + (0.626 * \ln(AK\_POP_y))\} \tag{42}$$

$$AK\_CN_y = 0.932946 + (0.937471 * AK\_CN_{y-1}) \tag{43}$$

$$(res): AKQTY\_F_{s=1,y} = \{e^{(6.983794*(1-0.364042))} * (AKQTY\_F_{s=1,y-1} * 1000)^{0.364042} * * AK\_RN_y^{(0.601932*(1-0.364042))}\} / 1000. \tag{44}$$

$$(com): AKQTY\_F_{s=2.y} = \{e^{(9.425307*(1-0.736334))} * (AKQTY\_F_{s=2,y-1} * 1000)^{0.736334} * AK\_CN_y^{0.205020} * (AK\_CN_{y-1} * 1000)^{(-0.736334*0.205020)}\} / 1000. \tag{45}$$

where,

$AKQTY\_F_{s=1}$	=	consumption of natural gas by residential (s=1) customers in Alaska in year y (MMcf, converted to Bcf, Table F1, Appendix F1)
$AKQTY\_F_{s=2}$	=	consumption of natural gas by commercial (s=2) customers in Alaska in the current forecast year y (MMcf, converted to Bcf, Table F1, Appendix F1)
AK_RN	=	number of residential customers in year y (thousands, Table F1, Appendix F)
AK_CN_y	=	number of commercial customers in year y (thousands, Table F2, Appendix F)
AK_POP	=	exogenously specified projection of the population in Alaska (thousands, Appendix E)

Gas consumption by Alaska industrial customers is set exogenously, as follows:

$$(ind): AKQTY\_F_{s=3,y} = AK\_QIND\_S_y \tag{46}$$

where,

$AKQTY\_F_{s=3,y}$	=	consumption of natural gas by industrial customers in year y (s=3), (Bcf)
AK_QIND_S	=	consumption of natural gas by industrial customers in southern Alaska (Bcf), the sum of consumption at the Agrium fertilizer plant (assumed to close in 2007, Appendix E) and at the Kenai LNG liquefaction facility (assumed to close in 2013, Appendix E)
s	=	sector
y	=	year

The production of gas in Alaska is basically set equal to the sum of the volumes consumed and transported out of Alaska, so depends on: 1) whether a pipeline is constructed from Alaska to

Alberta, 2) whether a gas-to-liquids plant is built in Alaska, and 3) consumption in and exports from Alaska. The production of gas related to the Alaska pipeline equals the volumes delivered to Alberta (which depend on assumptions about the pipeline capacity) plus what is consumed for related lease, plant, and pipeline operations (calculated as delivered volume divided by 1 minus the percent used for lease, plant, and pipeline operations). If the Petroleum Market Module (PMM) determines that a gas-to-liquids facility will be built in Alaska, then the natural gas consumed in the process (AKGTL_NGCNS, set in the PMM) is added to production in the north, along with the associated lease and plant fuel consumed. The production volumes related to the pipeline and the GTL plant are summed together ($N.AK_2$ below). Other production in North Alaska that is not related to the pipeline or GTL is largely lease and plant fuel associated with the crude oil extraction processes; whereas gas is produced in the south to satisfy consumption and export requirements. The quantity of lease and plant fuel not related to the pipeline or GTL in Alaska ($N.AK_1$ below) is assigned separately, includes lease and plant fuel used in the north and south, and is added to the other production ($N.AK_2$ below) to arrive at total North Alaska production. The details follow:

$$\begin{aligned}(\mathrm{S.AK}):\ & \mathrm{AK\_PROD}_{r=1} = \mathrm{AK\_CONS\_S} + \mathrm{EXPJAP} + \mathrm{QALK\_LAP\_S} + \\ & \mathrm{QALK\_PIP\_S} - \mathrm{AK\_DISCR}\end{aligned} \tag{47}$$

$$\begin{aligned}(\mathrm{N.AK_1}):\ & \mathrm{AK\_PROD}_{r=2} = \mathrm{QALK\_LAP\_N} = (0.0943884 * \mathrm{QALK\_LAP\_NLAG} \\ & + (0.038873 * \textstyle\sum_{s=1}^{3} \mathrm{oOGPRCOAK}_{s,y})\end{aligned} \tag{48}$$

$$\begin{aligned}(\mathrm{N.AK_2}):\ & \mathrm{AK\_PROD}_{r=3} = \frac{\mathrm{QAK\_ALB}_y}{1. - \mathrm{AK\_PCTLSE}_{r=3} - \mathrm{AK\_PCTPLT}_{r=3} - \mathrm{AK\_PCTPIP}_{r=3}} + \\ & \mathrm{AKGTL\_NGCNS}_t + \mathrm{AKGTL\_LAP}\end{aligned} \tag{49}$$

where,

$$\mathrm{AK\_CONS\_S} = \sum_{s=1}^{4} (\mathrm{AKQTY\_F}_s + \mathrm{AKQTY\_I}_s) \tag{50}$$

$$\mathrm{QALK\_LAP\_S} = 0.0 \qquad \text{(total is assigned to the North)} \tag{51}$$

$$\mathrm{QALK\_PIP\_S} = (\mathrm{AK\_CONS\_S} + \mathrm{EXPJAP}) * \mathrm{AK\_PCTPIP}_2 \tag{52}$$

$$\mathrm{AKGTL\_LAP} = \mathrm{oAKGTL\_NGCNS}_t * (\mathrm{AK\_PCTLSE}_3 + \mathrm{AK\_PCTPLT}_3) \tag{53}$$

where,

$\mathrm{AK\_PROD}_r$ = dry gas production in Alaska (Bcf)
AK_CONS_S = total gas delivered to customers in South Alaska (Bcf)
$\mathrm{AKQTY\_F}_s$ = total gas delivered to core customers in Alaska in sector s (Bcf)
$\mathrm{AKQTY\_I}_s$ = total gas delivered to non-core customers in Alaska in sector s (Bcf)

EXPJAP	=	quantity of gas liquefied and exported to Japan (from OGSM in Bcf)
QALK_LAP_N	=	quantity of gas consumed in Alaska for lease and plant operations, excluding that related to the Alaska pipeline and GTL (Bcf)
QALK_LAP_NLAG	=	quantity of gas consumed for lease and plant operations in the previous year, excluding that related to the pipeline and GTL (Bcf)
$oOGPRCOAK_{s,y}$	=	crude oil production in Alaska by sector
$QALK\_PIP_r$	=	quantity of gas consumed as pipeline fuel (Bcf)
AK_DISCR	=	discrepancy, the average (2006-2008) historically based difference in reported supply levels and consumption levels in Alaska (Bcf)
QAK_ALB_t	=	gas produced on North Slope entering Alberta via pipeline (Bcf)
AK_PCTLSE_r	=	(for r=1) not used, (for r=2) lease and plant consumption as a percent of gas consumption, (for r=3) lease consumption as a percent of gas production (fraction, Appendix E)
AK_PCTPLT_r	=	(for r=1 and r=2) not used, (for r=3) plant fuel as a percent of gas production (fraction, Appendix E)
AK_PCTPIP_r	=	(for r=1) not used, (for r=2) pipeline fuel as a percent of gas consumption, (for r=3) pipeline fuel as a percent of gas production (fraction, Appendix E)
$AKGTL\_NGCNS_t$	=	natural gas consumed in a gas-to-liquids plant in the North Slope (from PMM in Bcf)
AKGTL_LAP	=	lease and plant consumption associated with the gas for a gas-to-liquids plant (Bcf)
s	=	sectors (1=residential, 2=commercial, 3=industrial, 4=transportation, 5=electric generators)
r	=	region (1 = south, 2 = north not associated with a pipeline to Alberta or gas-to-liquids process, 3 = north associated with a pipeline to Alberta and/or a gas-to-liquids plant

Lease, plant, and pipeline fuel consumption are calculated as follows. For south Alaska, the calculation of pipeline fuel (QALK_PIP_S) and lease and plant fuel (QALK_LAP_S) are shown above. For the Alaska pipeline, all three components are set to the associated production times the percentage of lease (AK_PCTLSE_3), plant (AK_PCTPLT_3), or pipeline fuel (AK_PCTPIP_3). For the gas-to-liquids process, lease and plant fuel (AKGTL_LAP) is calculated as shown above and pipeline fuel is considered negligible. For the rest of north Alaska, pipeline fuel consumption is assumed to be negligible, while lease and plant fuel not associated with the pipeline or GTL (QALK_LAP_N) is set based on an estimated equation shown previously (Table F10, Appendix F).

Estimates for natural gas wellhead and delivered prices in Alaska are estimated in the NGTDM for proper accounting, but have a very limited impact on the NEMS system. The average Alaska wellhead price (AK_WPRC) over the North and South regions (not accounting for the impact if a pipeline ultimately is connected to Alberta) is set using the following estimated equation:

$$AK\_WPRC_1 = WPRLAG^{0.934077} * oIT\_WOP_{y,1}{}^{(0.280960*(1-0.934077))} \qquad (54)$$

where,

AK_WPRC_1 = natural gas wellhead price in Alaska, presuming no pipeline to Alberta (1987$/Mcf) (Table F1, Appendix F)
WPRLAG = AK_WPRC in the previous forecast year ($/Mcf)
$oIT\_WOP_{y,1}$ = world oil price (1987$ per barrel)

The price for natural gas associated with a pipeline to Alberta is exogenously specified ($FR\_PMINWPR_1$, Appendix E) and does not vary by forecast year. The average wellhead price for the State is calculated as the quantity-weighted average of AK_WPRC and $FR\_PMINWPR_1$. Delivered prices in Alaska are set equal to the wellhead price (AK_WPRC) resulting from the equation above plus a fixed, exogenously specified markup (Appendix E -- AK_RM, AK_CM, AK_IN, AK_EM).

Within the model, the commencement of construction of the Alaska to Alberta pipeline is restricted to the years beyond an earliest start date (FR_PMINYR, Appendix E) and can only occur if a pipeline from the MacKenzie Delta to Alberta is not under construction. The same is true for the MacKenzie Delta pipeline relative to construction of the Alaska pipeline. Otherwise, the structural representation of the MacKenzie Delta pipeline is nearly identical to that of the Alaska pipeline, with different numerical values for model parameters. Therefore, the following description applies to both pipelines. Within the model the same variable names are used to specify the supporting data for the two pipelines, with an index of 1 for Alaska and an index of 2 for the MacKenzie Delta pipeline.

The decision to build a pipeline is triggered if the estimated cost to supply the gas to the lower 48 States is lower than an average of the lower 48 average wellhead price over the planning period of FR_PPLNYR (Appendix E) years.[37] Construction is assumed to take FR_PCNSYR (Appendix E) years. Initial pipeline capacity is assumed to accommodate a throughput delivered to Alberta of FR_PVOL (Appendix E). The first year of operation, the volume is assumed to be half of its ultimate throughput. If the trigger price exceeds the minimum price by FR_PADDTAR (Appendix E) after the initial pipeline is built, then the capacity will be expanded the following year by a fraction (FR_PEXPFAC, Appendix E) of the original capacity.

The expected cost to move the gas to the lower 48 is set as the sum of the wellhead price,[38] the charge for treating the gas, and the fuel costs (FR_PMINWPR, Appendix E), plus the pipeline tariff for moving the gas to Alberta and an assumed differential between the price in Alberta and the average lower 48 wellhead price (ALB_TO_L48, Appendix E). A risk premium is also included to largely reflect the expected initial price drop as a result of the introduction of the pipeline, as well as some of the uncertainties in the necessary capital outlays and in the ultimate

[37]The prices are weighted, with a greater emphasis on the prices in the recent past. An additional check is made that the estimated cost is lower than the lower 48 price in the last two years of the planning period and lower than a weighted average of the expected prices in the three years after the planning period, during the construction period.

[38]The required wellhead price in the MacKenzie Delta is progressively adjusted in response to changes in the U.S. national average drilling cost per well projections and across the forecast horizon in a higher or lower technology case, such that by the last year (2035) the price is higher or lower than the price in the reference case by a fraction equal to 0.25 times the technology factor adjustment rate (e.g., 0.50 for *AEO2011*).

selling price (FR_PRISK, Appendix E).[39] The cost-of-service based calculation for the pipeline tariff (NGFRPIPE_TAR) to move gas from each production source to Alberta is presented at the end of Chapter 6.

[39]If there is an annual decline in the average lower 48 wellhead price over the planning period for the Alaska pipeline, an additional adjustment is made to the expected cost (although it is not a cost item), equivalent to half of the drop in price averaged over the planning period, to account for the additional concern created by declining prices.

3. Overview of Solution Methodology

The previous chapter described the function of the NGTDM within the NEMS and the transformation and representation of supply and demand elements within the NGTDM. This chapter will present an overview of the NGTDM model structure and of the methodologies used to represent the natural gas transmission and distribution industries. First, a detailed description of the network used in the NGTDM to represent the U.S. natural gas pipeline system is presented. Next, a general description of the interrelationships between the submodules within the NGTDM is presented, along with an overview of the solution methodology used by each submodule.

NGTDM Regions and the Pipeline Flow Network

General Description of the NGTDM Network

In the NGTDM, a transmission and distribution network (**Figure 3-1**) simulates the interregional flow of gas in the contiguous United States and Canada in either the peak (December through March) or off-peak (April through November) period. This network is a simplified representation of the physical natural gas pipeline system and establishes the possible interregional transfers to move gas from supply sources to end-users. Each NGTDM region contains one transshipment node, a junction point representing flows coming into and out of the region. Nodes have also been defined at the Canadian and Mexican borders, as well as in eastern and western Canada. Arcs connecting the transshipment nodes are defined to represent flows between these nodes; and thus, to represent interregional flows. Each of these interregional arcs represents an aggregation of pipelines that are capable of moving gas from one region into another region. Bidirectional flows are allowed in cases where the aggregation includes some pipelines flowing one direction and other pipelines flowing in the opposite direction.[40] Bidirectional flows can also be the result of directional flow shifts within a single pipeline system due to seasonal variations in flows. Arcs leading from or to international borders generally[41] represent imports or exports. The arcs which are designated as "secondary" in **Figure 3-1** generally represent relatively low flow volumes and are handled somewhat differently and separately from those designated as "primary."

Flows are further represented by establishing arcs from the transshipment node to each demand sector/subregion represented in the NGTDM region. Demand in a particular NGTDM region can only be satisfied by gas flowing from that same region's transshipment node. Similarly, arcs are also established from supply points into transshipment nodes. The supply from each NGTDM/OGSM region is directly available to only one transshipment node, through which it must first pass if it is to be made available to the interstate market (at an adjoining transshipment

[40]Historically, one out of each pair of bidirectional arcs in Figure 3-1 represents a relatively small amount of gas flow during the year. These arcs are referred to as "the bidirectional arcs" and are identified as the secondary arcs in Figure 3-1, excluding 3 to 15, 5 to 10, 15 to E. Canada, 20 to 7, 21 to 11, 22 to 12, and Alaska to W. Canada. The flows along these arcs are initially set at the last historical level and are only increased (proportionately) when a known (or likely) planned capacity expansion occurs.

[41]Some natural gas flows across the Canadian border into the United States, only to flow back across the border without changing ownership or truly being imported. In addition, any natural gas that might flow from Alaska to the lower 48 states would cross the Canadian/U.S. border, but not be considered as an import.

node). During a peak period, one of the supply sources feeding into each transshipment node represents net storage withdrawals in the region during the peak period. Conversely during the off-peak period, one of the demand nodes represents net storage injections in the region during the off-peak period.

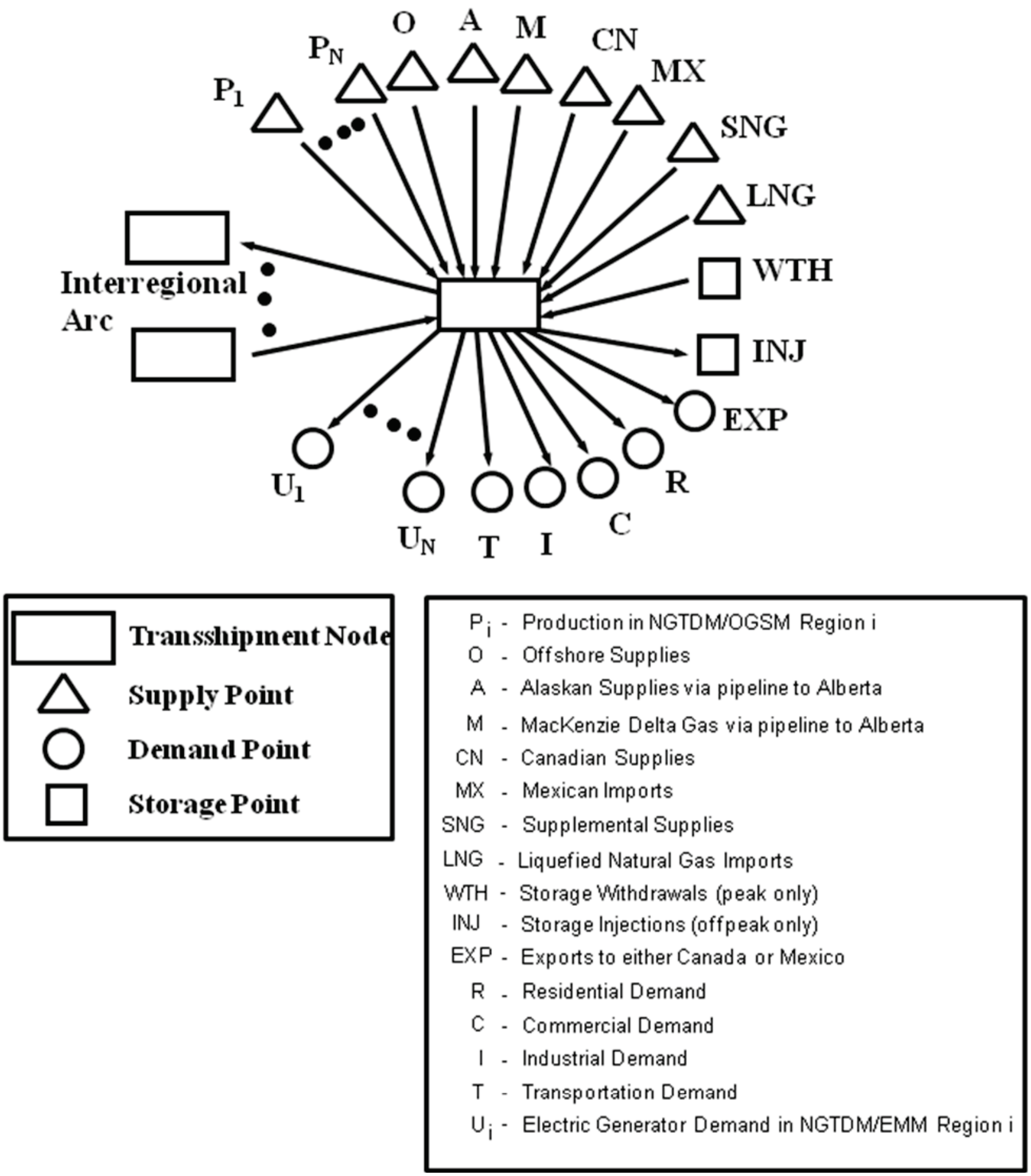
Figure 3-1. Natural Gas Transmission and Distribution Module Network

Figure 3-2 shows an illustration of all possible flows into and out of a transshipment node. Each transshipment node has one or more arcs to represent flows from or to other transshipment nodes. The transshipment node also has an arc representing flow to each end-use sector in the region (residential, commercial, industrial, electric generators, and transportation), including separate arcs to each electric generator subregion.[42] Exports and (in the off-peak period) net storage injections are also represented as flow out of a transshipment node. Each transshipment node can have one or more arcs flowing in from each supply source represented within the region. These supply points represent U.S. or Canadian onshore or U.S. offshore production,

[42]Conceptually within the model, the flow of gas to each end-use sector passes through a common city gate point before reaching the end-user.

liquefied natural gas imports, gas produced in Alaska and transported via pipeline, Mexican imports, (in the peak period) net storage withdrawals in the region, or supplemental gas supplies.

Figure 3-2. Transshipment Node



Two items accounted for but not presented in **Figure 3-2** are discrepancies or balancing items (i.e., average historically observed differences between independently reported natural gas supply and disposition levels (DISCR for the United States, CN_DISCR for Canada) and backstop supplies.[43]

Many of the types of supply listed above are relatively low in volume and are set independently of current prices and before the NGTDM determines a market equilibrium solution. As a result, these sources of supply are handled differently within the model. Structurally within the model only the price responsive sources of supply (i.e., onshore and offshore lower 48 U.S. production, Western Canadian Sedimentary Basin (WCSB) production, and storage withdrawals) are explicitly represented with supply nodes and connecting arcs to the transshipment nodes when the NGTDM is determining a market equilibrium solution.

Once the types of end-use destinations and supply sources into and out of each transshipment node are defined, a general network structure is created. Each transshipment node does not necessarily have all supply source types flowing in, or all demand source types flowing out. For instance, some transshipment nodes will have liquefied natural gas available while others will not. The specific end-use sectors and supply types specified for each transshipment node in the network are listed in **Table 3-1**. This table also provides the mapping of Electricity Market Module regions and Oil and Gas Supply Module regions to NGTDM regions (**Figure 2-3** and **Figure 2-5** in Chapter 2). The transshipment node numbers in the U.S. align with the NGTDM regions in **Figure 3-1**. Transshipment nodes 13 through 19 are pass-through nodes for the border crossings on the Canada/U.S. border, going from east to west.

As described earlier, the NGTDM determines the flow and price of natural gas in both a peak and off-peak period. The basic network structure separately represents the flow of gas during the two periods within the Interstate Transmission Submodule. Conceptually this can be thought of as two parallel networks, with three areas of overlap. First, pipeline expansion is determined only in the peak period network (with the exception of pipelines going into Florida from the East South Central Division). These levels are then used as constraints for pipeline flow in the off-peak period. Second, net withdrawals from storage in the peak period establish the net amount of natural gas that will be injected in the off-peak period, within a given forecast year. Similarly, the price of gas withdrawn in the peak period is the sum of the price of the gas when it was injected in the off-peak, plus an established storage tariff. Third, the supply curves provided by the Oil and Gas Supply Module are specified on an annual basis. Although, these curves are used to approximate peak and off-peak supply curves, the model is constrained to solve on the annual supply curve (i.e., when the annual curve is evaluated at the quantity-weighted average annual wellhead price, the resulting quantity should equal the sum of the production in the peak and off-peak periods). The details of how this is accomplished are provided in Chapter 4.

[43]Backstop supplies are allowed when the flow out of a transshipment node exceeds the maximum flow into a transshipment node. A high price is assigned to this supply source and it is generally expected not to be required (or desired). Chapter 4 provides a more detailed description of the setting and use of backstop supplies in the NGTDM.

Table 3-1. Demand and Supply Types at Each Transshipment Node in the Network

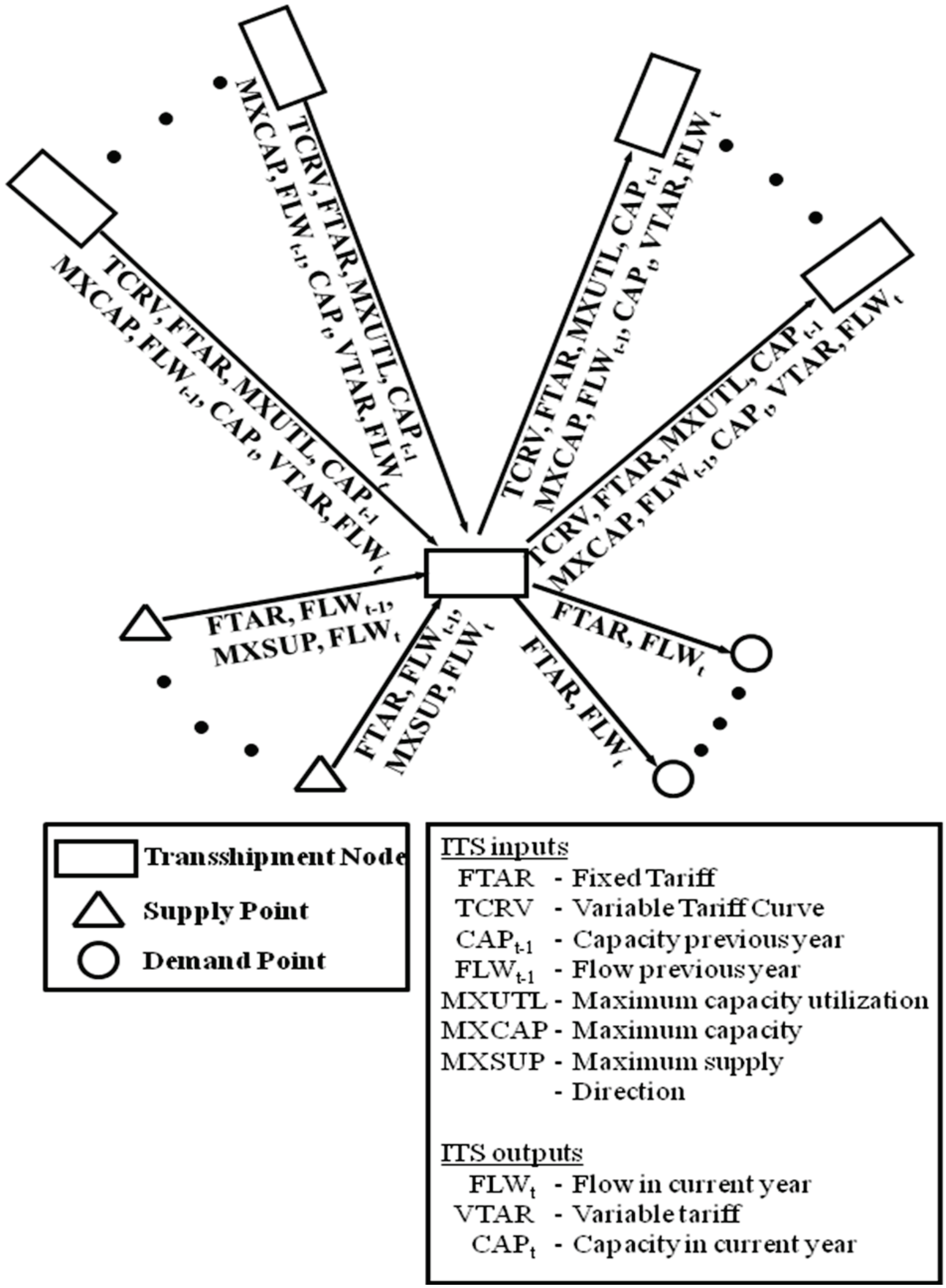
Transshipment Node	Demand Types	Supply Types
1	R, C, I, T, U(1)	P(1/1), LNG Everett Mass., LNG generic, SNG
2	R, C, I, T, U(2), INJ	P(2/1), WTH, LNG generic, SNG
3	R, C, I, T, U(3), U(4), INJ	P(3/1), WTH, SNG
4	R, C, I, T, U(5), INJ	P(4/3), P(4/5), SNG, WTH, LNG generic
5	R, C, I, T, U(6), U(7), INJ	P(5/1), LNG Cove Pt Maryland, LNG Elba Island Georgia, Atlantic Offshore, WTH, LNG generic, SNG
6	R, C, I, T, U(9), U(10), INJ	P(6/1), P(6/2), WTH, LNG generic, SNG
7	R, C, I, T, U(11), INJ	P(7/2), P(7/3), P(7/4), LNG Lake Charles Louisiana, Offshore Louisiana, Gulf of Mexico, WTH, LNG generic, SNG
8	R, C, I, T, U(12), U(13), INJ	P(8/5), WTH, SNG
9	R, C, I, T, U(15), INJ	P(9/6), WTH, LNG generic, SNG
10	R, C, I, T, U(6), U(8), INJ	P(10/2), WTH, SNG
11	R, C, I, T, U(14), INJ	P(11/4), P(11/5), WTH, SNG
12	R, C, I, T, U(16), INJ	P(12/6), Pacific Offshore, WTH, LNG generic, SNG
13 – 19	--	--
20	Mexican Exports (TX)	Mexican Imports (TX)
21	Mexican Exports (AZ/NM)	Mexican Imports (AZ/NM)
22	Mexican Exports (CA)	Mexican Imports (CA)
23	Eastern Canadian consumption, INJ	Eastern Canadian supply, WTH
24	Western Canadian consumption, INJ	Western Canadian supply, WTH, Alaskan Supply via a pipeline, MacKenzie Valley gas via a pipeline
P(x/y) – production in region defined in Figure 2-5 for NGTDM region x and OGSM region y U(z) – electric generator consumption in region z, defined in Figure 2-3		

Specifications of a Network Arc

Each arc of the network has associated variable inputs and outputs. The variables that define an interregional arc in the Interstate Transmission Submodule (ITS) are the pipeline direction, available capacity from the previous forecast year, the "fixed" tariffs and/or tariff curve, the flow on the arc from the previous year, the maximum capacity level, and the maximum utilization of the capacity (**Figure 3-3**). While a model solution is determined (i.e., the quantity of the natural gas flow along each interregional arc is determined), the "variable" or quantity dependent tariff and the required capacity to support the flow are also determined in the process.

For the peak period, the maximum capacity build levels are set to a factor above the 1990 levels. The factor is set high enough so that this constraint is rarely, if ever, binding. However, the structure could be used to limit growth along a particular path. In the off-peak period the maximum capacity levels are set to the capacity level determined in the peak period. The maximum utilization rate along each arc is used to capture the impact that varying demand loads over a season have on the utilization along an arc.

Figure 3-3. Variables Defined and Determined for Network Arc



For the peak period, the maximum utilization rate is calculated based on an estimate of the ratio of January-to-peak period consumption requirements. For the off-peak the maximum utilization rates are set exogenously (HOPUTZ, Appendix E). Capacity and flow levels from the previous forecast year are used as input to the solution algorithm for the current forecast year. In some cases, capacity that is newly available in the current forecast year will be exogenously set (PLANPCAP, Appendix E) as "planned" (i.e., highly probable that it will be built by the given forecast year based on project announcements). Any additional capacity beyond the planned level is determined during the solution process and is checked against maximum capacity levels and adjusted accordingly. Each of the interregional arcs has an associated "fixed" and "variable" tariff, to represent usage and reservation fees, respectively. The variable tariff is established by applying the flow level along the arc to the associated tariff supply curve, established by the Pipeline Tariff Submodule. During the solution process in the Interstate Transmission Submodule, the resulting tariff in the peak or off-peak period is added to the price at the source node to arrive at a price for the gas along the interregional arc right before it reaches its destination node. Through an iterative process, the relative values of these prices for all of the arcs entering a node are used as the basis for reevaluating the flow along each of these arcs.[44]

For the arcs from the transshipment nodes to the final delivery points, the variables defined are tariffs and flows (or consumption). The tariffs here represent the sum of several charges or adjustments, including interstate pipeline tariffs in the region, intrastate pipeline tariffs, and distributor markups. Associated with each of these arcs is the flow along the arc, which is equal to the amount of natural gas consumed by the represented sector. For arcs from supply points to transshipment nodes, the input variables are the production levels from the previous forecast year, a tariff, and the maximum limit on supplies or production. In this case the tariffs theoretically represent gathering charges, but are currently assumed to be zero.[45] Maximum supply levels are set at a percentage above a baseline or "expected" production level (described in Chapter 4). Although capacity limits can be set for the arcs to and from end-use sectors and supply points, respectively, the current version of the module does not impose such limits on the flows along these arcs.

Note that any of the above variables may have a value of zero, if appropriate. For instance, some pipeline arcs may be defined in the network that currently have zero capacity, yet where new capacity is expected in the future. On the other hand, some arcs such as those to end-use sectors are defined with infinite pipeline capacity because the model does not forecast limits on the flow of gas from transshipment nodes to end users.

Overview of the NGTDM Submodules and Their Interrelationships

The NEMS generates an annual forecast of the outlook for U.S. energy markets for the years 1990 through 2030. For the historical years, many of the modules in NEMS do not execute, but

[44]During the off-peak period in a previous version of the module, only the usage fee was used as a basis for determining the relative flow along the arcs entering a node. However, the total tariff was ultimately used when setting delivered prices.

[45]Ultimately the gathering charges are reflected in the delivered prices when the model is benchmarked to historically reported city gate prices.

simply assign historically published values to the model's output variables. The NGTDM similarly assigns historical values to most of the known module outputs for these years. However, some of the required outputs from the module are not known (e.g., the flow of natural gas between regions on a seasonal basis). Therefore, the model is run in a modified form to fill in such unknown, but required values. Through this process historical values are generated for the unknown parameters that are consistent with the known historically based values (e.g., the unknown seasonal interregional flows sum to the known annual totals).

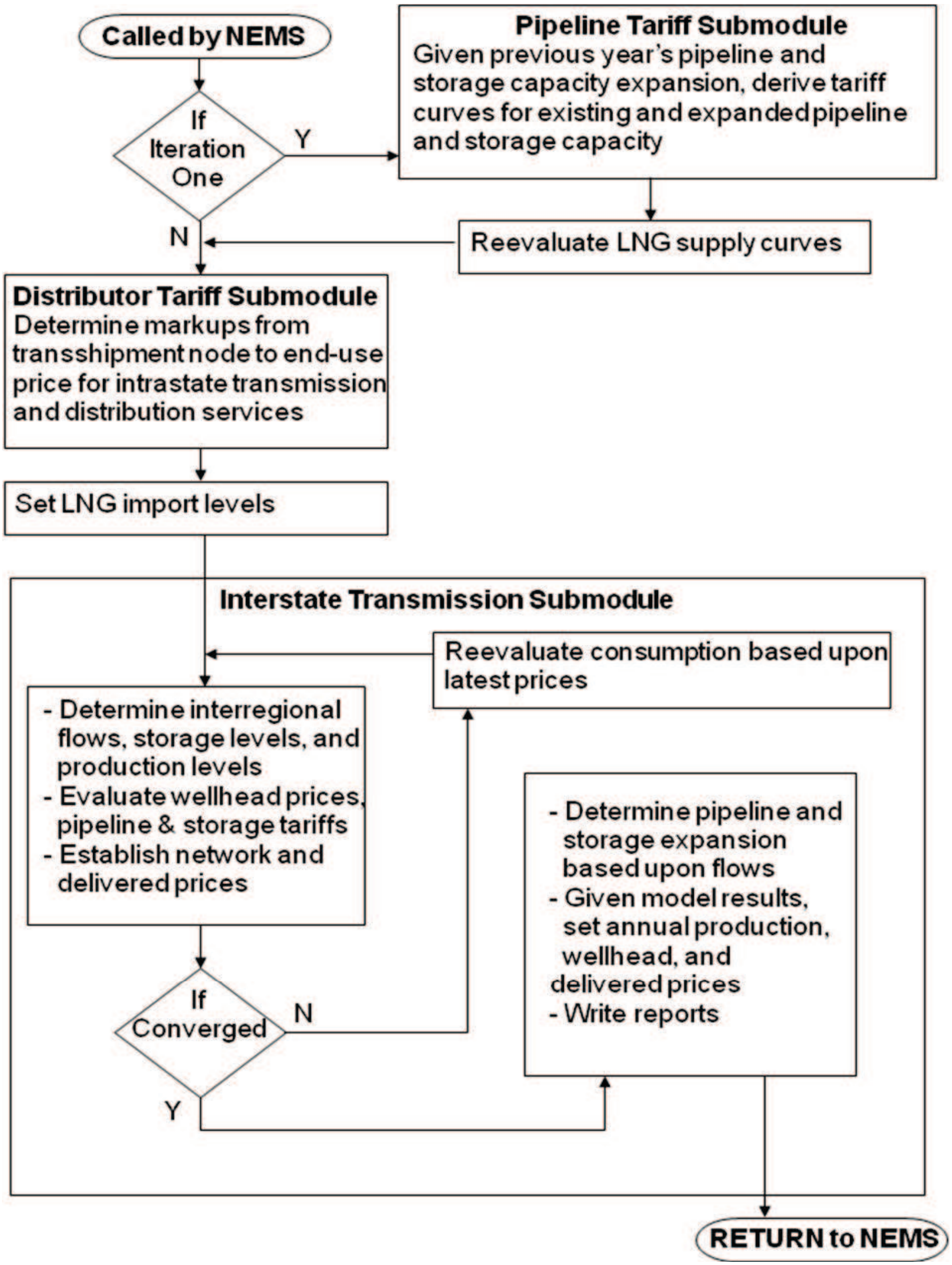
Although the NGTDM is executed for each iteration of each forecast year solved by the NEMS, it is not necessary that all of the individual components of the module be executed for all iterations. Of the NGTDM's three components or submodules, the Pipeline Tariff Submodule is executed only once per forecast year since the submodule's input values do not change from one iteration of NEMS to the next. However, the Interstate Transmission Submodule and the Distributor Tariff Submodule are executed during every iteration for each forecast year because their input values can change by iteration. Within the Interstate Transmission Submodule an iterative process is used. The basic solution algorithm is repeated multiple times until the resulting wellhead prices and production levels from one iteration are within a user-specified tolerance of the resulting values from the previous iteration, and equilibrium is reached. A process diagram of the NGTDM is provided in **Figure 3-4**, with the general calling sequence.

The Interstate Transmission Submodule is the primary submodule of the NGTDM. One of its functions is to forecast interregional pipeline and underground storage expansions and produce annual pipeline load profiles based on seasonal loads. Using this information from the previous forecast year and other data, the Pipeline Tariff Submodule uses an accounting process to derive revenue requirements for the current forecast year. This submodule builds pipeline and storage tariff curves based on these revenue requirements for use in the Interstate Transmission Submodule. These curves extend beyond the level of the current year's capacity and provide a means for assessing whether the demand for additional capacity, based on a higher tariff, is sufficient to warrant expansion of the capacity. The Distributor Tariff Submodule provides distributor tariffs for use in the Interstate Transmission Submodule. The Distributor Tariff Submodule must be called in each iteration because some of the distributor tariffs are based on consumption levels that may change from iteration to iteration. Finally, using the information provided by these other NGTDM submodules and other NEMS modules, the Interstate Transmission Submodule solves for natural gas prices and quantities that reflect a market equilibrium for the current forecast year. A brief summary of each of the NGTDM submodules follows.

Interstate Transmission Submodule

The Interstate Transmission Submodule (ITS) is the main integrating module of the NGTDM. One of its major functions is to simulate the natural gas price determination process. The ITS brings together the major economic factors that influence regional natural gas trade on a seasonal basis in the United States, the balancing of the demand for and the domestic supply of natural gas, including competition from imported natural gas. These are examined in combination with the relative prices associated with moving the gas from the producer to the end-user where and

Figure 3-4. NGTDM Process Diagram



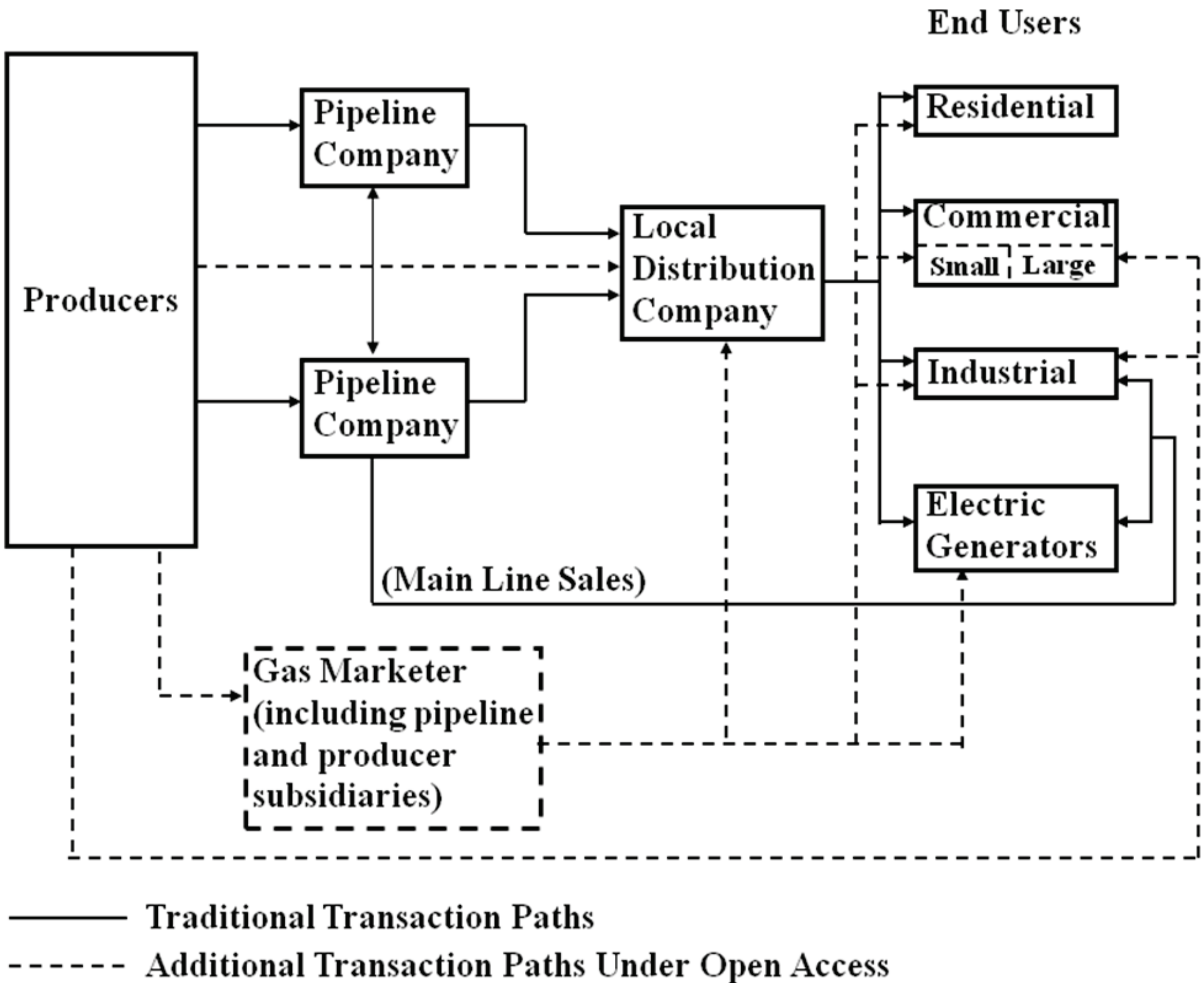
when (peak versus off-peak) it is needed. In the process, the ITS models the decision-making process for expanding pipeline and/or seasonal storage capacity in the U.S. gas market, determining the amount of pipeline and storage capacity to be added between or within regions in the NGTDM. Storage serves as the primary link between the two seasonal periods represented.

The ITS employs an iterative heuristic algorithm to establish a market equilibrium solution. Given the consumption levels from other NEMS modules, the basic process followed by the ITS involves first establishing the backward flow of natural gas in each period from the consumers, through the network, to the producers, based primarily on the relative prices offered for the gas (from the previous ITS iteration). This process is performed for the peak period first since the net withdrawals from storage during the peak period will establish the net injections during the off-peak period. Second, using the model's supply curves, wellhead prices are set corresponding to the desired production volumes. Also, using the pipeline and storage tariff curves from the Pipeline Tariff Submodule, pipeline and storage tariffs are set corresponding to the associated flow of gas, as determined in the first step. These prices are then translated from the producers, back through the network, to the city gate and the end-users, by adding the appropriate tariffs along the way. A regional storage tariff is added to the price of gas injected into storage in the off-peak to arrive at the price of the gas when withdrawn in the peak period. Delivered prices are derived for residential, commercial, electric generation, and transportation customers, as well as for both the core and non-core industrial sectors, using the distributor tariffs provided by the Distributor Tariff Submodule. At this point consumption levels can be reevaluated given the resulting set of delivered prices. Either way, the process is repeated until the solution has converged.

In the end, the ITS derives average seasonal (and ultimately annual) natural gas prices (wellhead, city gate, and delivered), and the associated production and flows, that reflect an interregional market equilibrium among the competing participants in the market. In the process of determining interregional flows and storage injections/withdrawals, the ITS also forecasts pipeline and storage capacity additions. In the calculations for the next forecast year, the Pipeline Tariff Submodule will adjust the requirements to account for the associated expansion costs. Other primary outputs of the module include lease, plant, and pipeline fuel use, Canadian import levels, and net storage withdrawals in the peak period.

The historical evolution of the price determination process simulated by the ITS is depicted schematically in **Figure 3-5**. At one point, the marketing chain was very straightforward, with end-users and local distribution companies contracting with pipeline companies, and the pipeline companies in turn contracting with producers. Prices typically reflected average costs of providing service plus some regulator-specified rate of return. Although this approach is still used as a basis for setting pipeline tariffs, more pricing flexibility has been introduced, particularly in the interstate pipeline industry and more recently by local distributors. Pipeline companies are also offering a range of services under competitive and market-based pricing arrangements. Additionally, newer players—for example marketers of spot gas and brokers for pipeline capacity—have entered the market, creating new links connecting suppliers with end-users. The marketing links are expected to become increasingly complex in the future.

Figure 3-5. Principal Buyer/Seller Transaction Paths for Natural Gas Marketing



The level of competition for pipeline services (generally a function of the number of pipelines having access to a customer and the amount of capacity available) drives the prices for interruptible transmission service and is having an effect on firm service prices. Currently, there are significant differences across regions in pipeline capacity utilization.[46] These regional differences are evolving as new pipeline capacity has been and is being constructed to relieve capacity constraints in the Northeast, to expand markets in the Midwest and the Southeast, and to move more gas out of the Rocky Mountain region and the Gulf of Mexico. As capacity changes take place, prices of services should adjust accordingly to reflect new market conditions.

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[46]Further information can be found on the U.S. Energy Information Administration web page under "Pipeline Capacity and Usage" www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html.

Federal and State initiatives are reducing barriers to market entry and are encouraging the development of more competitive markets for pipeline and distribution services. Mechanisms used to make the transmission sector more competitive include the widespread capacity releasing programs, market-based rates, and the formation of market centers with deregulated upstream pipeline services. The ITS is not designed to model any specific type of program, but to simulate the overall impact of the movement towards market based pricing of transmission services.

Pipeline Tariff Submodule

The primary purpose of the Pipeline Tariff Submodule (PTS) is to provide volume dependent curves for computing tariffs for interstate transportation and storage services within the Interstate Transmission Submodule. These curves extend beyond current capacity levels and relate incremental pipeline or storage capacity expansion to corresponding estimated rates. The underlying basis for each tariff curve in the model is a forecast of the associated regulated revenue requirement. An accounting system is used to track costs and compute revenue requirements associated with both reservation and usage fees under a current typical regulated rate design. Other than an assortment of macroeconomic indicators, the primary input to the PTS from other modules/submodules in NEMS is the level of pipeline and storage capacity expansions in the previous forecast year. Once an expansion is projected to occur, the submodule calculates the resulting impact on the revenue requirement. The PTS currently assumes rolled-in (or average), not incremental rates for new capacity (i.e., the cost of any additional capacity is lumped in with the remaining costs of existing capacity when deriving a single tariff for all the customers along a pipeline segment).

Transportation revenue requirements (and associated tariff curves) are established for interregional arcs defined by the NGTDM network. These network tariff curves reflect an aggregation of the revenue requirements for individual pipeline companies represented by the network arc. Storage tariff curves are defined at regional NGTDM network nodes, and similarly reflect an aggregation of individual company storage revenue requirements. Note that these services are unbundled and do not include the price of gas, except for the cushion gas used to maintain minimum gas pressure. Furthermore, the submodule cannot address competition for pipeline or storage services along an aggregate arc or within an aggregate region, respectively. It should also be noted that the PTS deals only with the interstate market, and thus does not capture the impacts of State-specific regulations for intrastate pipelines. Intrastate transportation charges are accounted for within the Distributor Tariff Submodule.

Pipeline tariffs for transportation and storage services represent a more significant portion of the price of gas to industrial and electric generator end-users than to other sectors. Consumers of natural gas are grouped generally into two categories: (1) those that need firm or guaranteed service because gas is their only fuel option or because they are willing to pay for security of supply, and (2) those that do not need guaranteed service because they can either periodically terminate operations or use fuels other than natural gas. The first group of customers (core customers) is assumed to purchase firm transportation services, while the latter group (non-core customers) is assumed to purchase non-firm service (e.g., interruptible service, released capacity). Pipeline companies guarantee to their core customers that they will provide peak day service up to the maximum capacity specified under their contracts even though these customers may not actually request transport of gas on any given day. In return for this service guarantee, these customers pay monthly reservation fees (or demand charges). These reservation fees are paid in addition to charges for transportation service based on the quantity of gas actually transported (usage fees or commodity charges). The pipeline tariff curves generated by the PTS are used within the ITS when determining the relative cost of purchasing and moving gas from one source versus another in the peak and off-peak seasons. They are also used when setting the price of gas along the NGTDM network and ultimately to the end-users.

The actual rates or tariffs that pipelines are allowed to charge are largely regulated by the Federal Energy Regulatory Commission (FERC). FERC's ratemaking traditionally allows (but does not necessarily guarantee) a pipeline company to recover its costs, including what the regulators consider a fair rate of return on capital. Furthermore, FERC not only has jurisdiction over how cost components are allocated to reservation and usage categories, but also how reservation and usage costs are allocated across the various classes of transmission (or storage) services offered (e.g., firm versus non-firm service). Previous versions of the NGTDM (and therefore the PTS) included representations of natural gas moved (or stored) using firm and non-firm service. However, in an effort to simplify the module, this distinction has been removed in favor of moving from an annual to a seasonal model. The impact of the distinction of firm versus non-firm service on core and non-core delivered prices is indirectly captured in the markup established in the Distributor Tariff Submodule. More recent initiatives by FERC have allowed for more flexible processes for setting rates when a service provider can adequately demonstrate that it does not possess significant market power. The use of volume dependent tariff curves partially serves to capture the impact of alternate rate setting mechanisms. Additionally, various rate making policy options discussed by FERC would allow peak-season rates to rise substantially above the 100-percent load factor rate (also known as the full cost-of-service rate). In capacity-constrained markets, the basis differential between markets connected via the constrained pipeline route will generally be above the full cost of service pipeline rates. The NGTDM's ultimate purpose is to project market prices; it uses cost-of-service rates as a means in the process of establishing market prices.

Distributor Tariff Submodule

The primary purpose of the Distributor Tariff Submodule (DTS) is to determine the price markup from the regional market hub to the end-user. For most customers, this consists of (1) distributor markups charged by local distribution companies for the distribution of natural gas from the city gate to the end user and (2) markups charged by intrastate pipeline companies for intrastate transportation services. Intrastate pipeline tariffs are specified exogenously to the model and are currently set to zero (INTRAST_TAR, Appendix E). However, these tariffs are accounted for in the module indirectly. For most industrial and electric generator customers, gas is not purchased through a local distribution company, so they are not specifically charged a distributor tariff. In this case, the "distributor tariff" represents the difference between the average price paid by local distribution companies at the city gate and the price paid by the average industrial or electric generator customer. Distributor tariffs are distinguished within the DTS by sector (residential, commercial, industrial, transportation, and electric generator), region (NGTDM/EMM regions for electric generators and NGTDM regions for the rest), seasons (peak or off-peak), and as appropriate by service type or class (core or non-core).

Distribution markups represent a significant portion of the price of gas to residential, commercial, and transportation customers, and less so to the industrial and electric generation sectors. Each sector has different distribution service requirements, and frequently different transportation needs. For example, the core customers in the model (residential, transportation, commercial and some industrial and electric generator customers) are assumed to require guaranteed on-demand (firm) service because natural gas is largely their only fuel option. In contrast, large portions of the industrial and electric generator sectors may not rely solely on guaranteed service because they can either periodically terminate operations or switch to other fuels. These customers are referred to as non-core. They can elect to receive some gas supplies through a lower priority (and lower cost) interruptible transportation service. While not specifically represented in the model, during periods of peak demand, services to these sectors can be interrupted in order to meet the natural gas requirements of core customers. In addition, these customers frequently select to bypass the local distribution company pipelines and hook up directly to interstate or intrastate pipelines.

The rates that local distribution companies and intrastate carriers are allowed to charge are regulated by State authorities. State ratemaking traditionally allows (but does not necessarily guarantee) local distribution companies and intrastate carriers to recover their costs, including what the regulators consider a fair return on capital. These rates are derived from the cost of providing service to the end-use customer. The State authority determines which expenses can be passed through to customers and establishes an allowed rate of return. These measures provide the basis for distinguishing rate differences among customer classes and type of service by allocating costs to these classes and services based on a rate design. The DTS does not project distributor tariffs through a rate base calculation as is done in the PTS, partially due to limits on data availability.[47] In most cases, projected distributor tariffs in the model depend initially on base year values, which are established by subtracting historical city gate prices from historical delivered prices, and generally reflect an average over recent historical years.

Distributor tariffs for all but the transportation sector are set using econometrically estimated equations.[48] Transportation sector markups, representing sales for natural gas vehicles, are set separately for fleet and personal vehicles and account for distribution to delivery stations, retail markups, and federal and state motor fuels taxes. In addition, the NGTDM assesses the potential construction of infrastructure to support fueling compressed natural gas vehicles.

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[47] In theory these cost components could be compiled from rate filings to state Public Utility Commissions; however, such an extensive data collection effort is beyond the available resources.

[48] An econometric approach was used largely as a result of data limitations. EIA data surveys do not collect the cost components required to derive revenue requirements and cost-of-service for local distribution companies and intrastate carriers. These cost components can be compiled from rate filings to Public Utility Commissions; however, an extensive data collection effort is beyond the scope of NEMS at this time.

4. Interstate Transmission Submodule Solution Methodology

As a key component of the NGTDM, the Interstate Transmission Submodule (ITS) determines the market equilibrium between supply and demand of natural gas within the North American pipeline system. This translates into finding the price such that the quantity of gas that consumers would desire to purchase equals the quantity that producers would be willing to sell, accounting for the transmission and distribution costs, pipeline fuel use, capacity expansion costs and limitations, and mass balances. To accomplish this, two seasonal periods were represented within the module--a peak and an off-peak period. The network structures within each period consist of an identical system of pipelines, and are connected through common supply sources and storage nodes. Thus, two interconnected networks (peak and off-peak) serve as the framework for processing key inputs and balancing the market to generate the desired outputs. A heuristic approach is used to systematically move through the two networks solving for production levels, network flows, pipeline and storage capacity requirements,[49] supply and citygate prices, and ultimately delivered prices until mass balance and convergence are achieved. (The methodology used for calculating distributor tariffs is presented in Chapter 5.) Primary input requirements include seasonal consumption levels, capacity expansion cost curves, annual natural gas supply levels and/or curves, a representation of pipeline and storage tariffs, as well as values for pipeline and storage starting capacities, and network flows and prices from the previous year. Some of the inputs are provided by other NEMS modules, some are exogenously defined and provided in input files, and others are generated by the module in previous years or iterations and used as starting values. Wellhead, import, and delivered prices, supply quantities, and resulting flow patterns are obtained as output from the ITS and sent to other NGTDM submodules or other NEMS modules after some processing. Network characteristics, input requirements, and the heuristic process are presented more fully below.

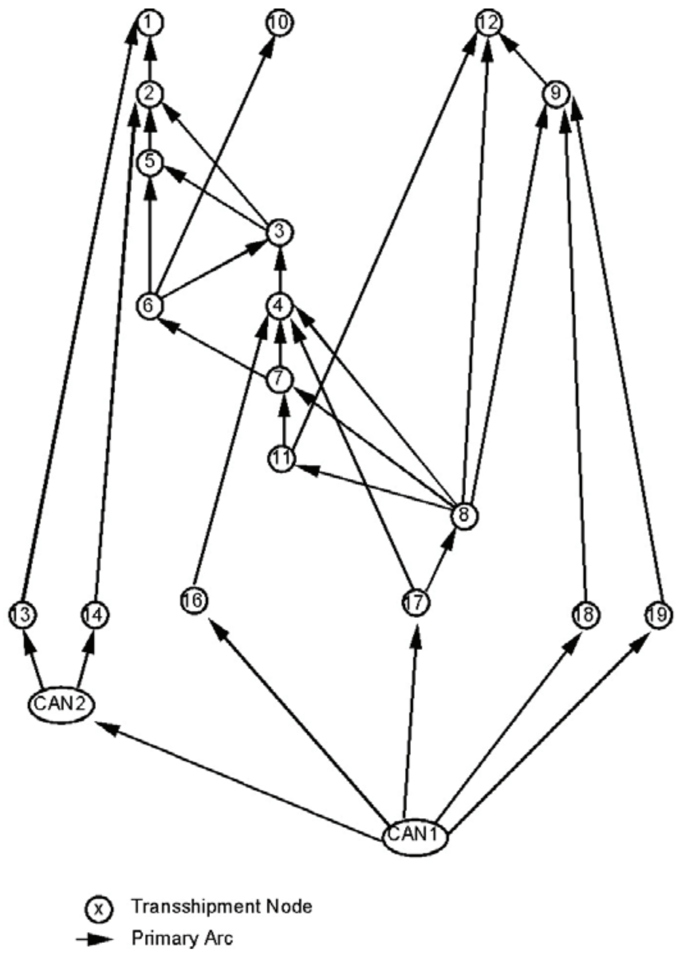
Network Characteristics in the ITS

As described in an earlier chapter, the NGTDM network consists of 12 NGTDM regions (or transshipment nodes) in the lower 48 states, three Mexican border crossing nodes, seven Canadian border crossing nodes, and two Canadian supply/demand regions. Interregional arcs connecting the nodes represent an aggregation of pipelines that are capable of moving gas from one region (or transshipment node) into another. These arcs have been classified as either primary flow arcs or secondary flow arcs. The primary flow arcs (see **Figure 3-1**) represent major flow corridors for the transmission of natural gas. Secondary arcs represent either flow in the opposite direction from the primary flow (historically about 3 percent of the total flow) or relatively low flow volumes that are set exogenously or outside the ITS equilibration routine (e.g. Mexican imports and exports). In the ITS, this North American natural gas pipeline flow network has been restructured into a hierarchical, acyclic network representing just the primary flow of natural gas (**Figure 4-1**). The representation of flows along secondary arcs is described in the Solution Process section below. A hierarchical, acyclic network structure allows for the

[49]In reality, capacity expansion decisions are made based on expectations of future demand requirements, allowing for regulatory approvals and construction lead times. In the model, additional capacity is available immediately, once it is determined that it is needed. The implicit assumption is that decision makers exercised perfect foresight and that planning and construction for the pipeline actually started before the pipeline came online.

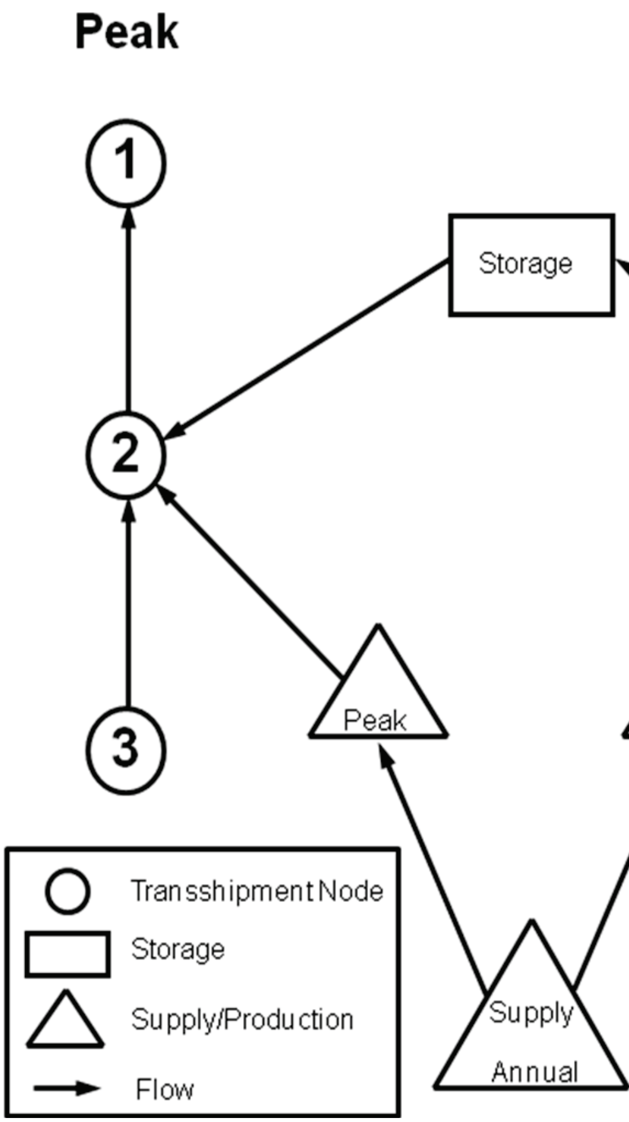
systematic representation of the flow of natural gas (and its associated prices) from the supply sources, represented towards the bottom of the network, up through the network to the end-use consumer at the upper end of the network.

Figure 4-1. Network "Tree" of Hierarchical, Acyclic Network of Primary Arcs



In the ITS, two interconnected acyclic networks are used to represent natural gas flow to end-use markets during the peak period (PK) and flow to end-use markets during the off-peak period (OP). These networks are connected regionally through common supply sources and storage nodes (**Figure 4-2**). Storage within the module only represents the transfer of natural gas produced in the off-peak period to meet the higher demands in the peak period. Therefore, net storage injections are included only in the off-peak period, while net storage withdrawals occur only in the peak period. Within a given forecast year, the withdrawal level from storage in the peak period establishes the level of gas injected in the off-peak period. Annual supply sources provide natural gas to both networks based on the combined network production requirements and corresponding annual supply availability in each region.

Figure 4-2. Simplified Example of Supply and Storage Links Across Networks



Input Requirements of the ITS

The following is a list of the key inputs required during ITS processing:

- Seasonal end-use consumption or demand curves for each NGTDM region and Canada
- Seasonal imports (except Canada) and exports by border crossing
- Canadian import capacities by border crossing
- Total natural gas production in eastern Canada and unconventional production in western Canada, by season.
- Natural gas flow by pipeline from Alaska to Alberta.
- Natural gas flow by pipeline from the MacKenzie Delta to Alberta.

- Regional supply curve parameters for U.S. nonassociated and western Canadian conventional natural gas supply[50]
- Seasonal supply quantities for U.S. associated-dissolved gas, synthetic gas, and other supplemental supplies by NGTDM region
- Seasonal network flow patterns from the previous year, by arc (including flows from storage, variable supply sources, and pipeline arcs)
- Seasonal network prices from the previous year, by arc (including flows from storage, variable supply sources, and pipeline arcs)
- Pipeline capacities, by arc
- Seasonal maximum pipeline utilizations, by arc
- Seasonal pipeline (and storage) tariffs representing variable costs or usage fees, by arc (and region)
- Pipeline capacity expansion/tariff curves for the peak network, by arc
- Storage capacity expansion/tariff curves for the peak network, by region
- Seasonal distributor tariffs by sector and region

Many of the inputs are provided by other NEMS submodules, some are defined from data within the ITS, and others are ITS model results from operation in the previous year. For example, supply curve parameters for lower 48 nonassociated onshore and offshore natural gas production and lower 48 associated-dissolved gas production are provided by the Oil and Gas Supply Module (OGSM). In contrast, Canadian data are set within the NGTDM as direct input to the ITS. U.S. end-use consumption levels are provided by NEMS demand modules; pipeline and storage capacity expansion/tariff curve parameters are provided by the Pipeline Tariff Submodule (PTS, see chapter 6); and seasonal distributor tariffs are defined by the Distributor Tariff Submodule (DTS, see Chapter 5). Seasonal network flow patterns and prices are determined within the ITS. They are initially set based on historical data, and then from model results in the previous model year.

Because the ITS is a seasonal model, most of the input requirements are on a seasonal level. In most cases, however, the information provided is not represented in the form defined above and needs to be processed into the required form. For example, regional end-use consumption levels are initially defined by sector on an annual basis. The ITS disaggregates each of these sector-specific quantities into a seasonal peak and off-peak representation, and then aggregates across sectors within each season to set a total consumption level. Also, regional fixed supplies and some of the import/export levels represent annual values. A simple methodology has been developed to disaggregate the annual information into peak and off-peak quantities using item-specific peak sharing factors (e.g., PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, PKSHR_SUPLM, PKSHR_ILNG, and PKSHR_YR). For more detail on these inputs see Chapter 2. A similar method is used to approximate the consumption and supply in the peak month of each period. This information is used to verify that sufficient sustained[51] capacity is available for the peak day in each period; and if not, it is used as a basis for adding

[50]These supply sources are referred to as the "variable" supplies because they are allowed to change in response to price changes during the ITS solution process. A few of the "fixed" supplies are adjusted each NEMS iteration, generally in response to price, but are held constant within the ITS solution process.

[51]"Sustained" capacity refers to levels that can operationally be sustained throughout the year, as opposed to "peak" capacity which can be realized at high pressures and would not generally be maintained other than at peak demand periods.

additional capacity. The assumption reflected in the model is that, if there is sufficient sustained capacity to handle the peak month, line packing[52] and propane injection can be used to accommodate a peak day in this month.

Heuristic Process

The basic process used to determine supply and delivered prices in the ITS involves starting from the top of the hierarchical, acyclic network or "tree" (as shown in **Figure 4-1**) with end-use consumption levels, systematically moving down each network (in the opposite direction from the primary flow of gas) to define seasonal flows along network arcs that will satisfy the consumption, evaluating wellhead prices for the desired production levels, and then moving up each network (in the direction of the primary flow of gas) to define transmission, node, storage, and delivered prices.

While progressively moving down the peak or off-peak network, net regional demands are assigned for each node on each network. Net regional demands are defined as the sum of consumption in the region plus the gas that is exiting the region to satisfy consumption elsewhere, net of fixed[53] supplies in the region. The consumption categories represented in net regional demands include end-use consumption in the region, exports, pipeline fuel consumption, secondary and primary flows out of the region, and for the off-peak period, net injections into regional storage facilities. Regional fixed supplies include imports (except conventional gas from Western Canada), secondary flows into the region, and the regions associated-dissolved production, supplemental supplies, and other fixed supplies. The net regional demands at a node will be satisfied by the gas flowing along the primary arcs into the node, the local "variable" supply flowing into the node, and for the peak period, the gas withdrawn from the regional storage facilities on a net basis.

Starting with the node(s) at the top of the network tree (i.e., nodes 1, 10, and 12 in **Figure 4-1**), the model uses a sharing algorithm to determine the percent of the represented region's net demand that is satisfied by each arc going into the node. The resulting shares are used to define flows along each arc (supply, storage, and interregional pipeline) into the region (or node). The interregional flows then become additional consumption requirements (i.e., primary flows out of a region) at the corresponding source node (region). If the arc going into the original node is from a supply or storage[54] source, then the flow represents the production or storage withdrawal level, respectively. The sharing algorithm is systematically applied (going down the network tree) to each regional node until flows have been defined for all arcs along a network, such that consumption in each region is satisfied.

Once flows are established for each network (and pipeline tariffs are set by applying the flow levels to the pipeline tariff curves), resulting production levels for the variable supplies are used to determine regional wellhead prices and, ultimately, storage, node, and delivered prices. By

[52]Line packing is a means of storing gas within a pipeline for a short period of time by compressing the gas.
[53]Fixed supplies are those supply sources that are not allowed to vary in response to changes in the natural gas price during the ITS solution process.
[54]For the peak period networks only.

systematically moving up each network tree, regional wellhead prices are used with pipeline tariffs, while adjusting for price impacts from pipeline fuel consumption, to calculate regional node prices for each season. Next, intraregional and intrastate markups are added to the regional/seasonal node prices, followed by the addition of corresponding seasonal, sectoral distributor tariffs, to generate delivered prices. Seasonal prices are then converted to annual delivered prices using quantity-weighted averaging. To speed overall NEMS convergence,[55] the delivered prices can be applied to representative demand curves to approximate the demand response to a change in the price and to generate a new set of consumption levels. This process of going up and down the network tree is repeated until convergence is reached.

The order in which the networks are solved differs depending on whether movement is down or up the network tree. When proceeding down the network trees, the peak network flows are established first, followed by the off-peak network flows. This order has been established for two reasons. First, capacity expansion is decided based on peak flow requirements.[56] This in turn is used to define the upper limits on flows along arcs in the off-peak network. Second, net storage injections (represented as consumption) in the off-peak season cannot be defined until net storage withdrawals (represented as supplies) in the peak season are established. When going up the network trees, prices are determined for the off-peak network first, followed by the peak network. This order has been established mainly because the price of fuel withdrawn from storage in the peak season is based on the cost of fuel injected into storage in the off-peak season plus a storage tariff.

If net demands exceed available supplies on a network in a region, then a backstop supply is made available at a higher price than other local supply. The higher price is passed up the network tree to discourage (or decrease) demands from being met via this supply route. Thus, network flows respond by shifting away from the backstop region until backstop supply is no longer needed.

Movement down and up each network tree (defined as a cycle) continues within a NEMS iteration until the ITS converges. Convergence is achieved when the regional seasonal supply prices determined during the current cycle down the network tree are within a designated minimum percentage tolerance from the supply prices established the previous cycle down the network tree. In addition, the absolute change in production between cycles within supply regions with relatively small production levels are checked in establishing convergence. In addition, the presence of backstop will prevent convergence from being declared. Once convergence is achieved, only one last movement up each network tree is required to define final regional/seasonal node and delivered prices. If convergence is not achieved, then a set of "relaxed" supply prices is determined by weighting regional production results from both the current and the previous cycle down the network tree, and obtaining corresponding new annual and seasonal supply prices from the supply curves in each region based on these "relaxed" production levels. The concept of "relaxation" is a means of speeding convergence by solving

[55]At various times, NEMS has not readily converged and various approaches have been taken to improve the process. If the NGTDM can anticipate the potential demand response to a price change from one iteration to the next, and accordingly moderate the price change, the NEMS will theoretically converge to an equilibrium solution in less iterations.

[56]Pipeline capacity into region 10 (Florida) is allowed to expand in either the peak or off-peak period because the region experiences its peak usage of natural gas in what is generally the off-peak period for consumption in the rest of the country.

for quantities (or prices) in the current iteration based on a weighted-average of the prices (or quantities) from the previous two iterations, rather than just using the previous iteration's values.[57]

The following subsections describe many of these procedures in greater detail, including: net node demands, pipeline fuel consumption, sharing algorithm, wellhead prices, tariffs, arc, node, and storage prices, backstop, convergence, and delivered and import prices. A simple flow diagram of the overall process is presented in **Figure 4-3**.

Net Node Demands

Seasonal net demands at a node are defined as total seasonal demands in the region, net of seasonal fixed supplies entering the region. Regional demands consist of primary flows exiting the region (including net storage injections in the off-peak), pipeline fuel consumption, end-use consumption, discrepancies (or historical balancing item), Canadian consumption, exports, and other secondary flows exiting the region. Fixed supplies include associated-dissolved gas, Alaskan gas supplies to Alberta, synthetic natural gas, other supplemental supplies, LNG imports, fixed Canadian supplies (including MacKenzie Delta gas), and other secondary flows entering the region. Seasonal net node demands are represented by the following equations:

Peak:

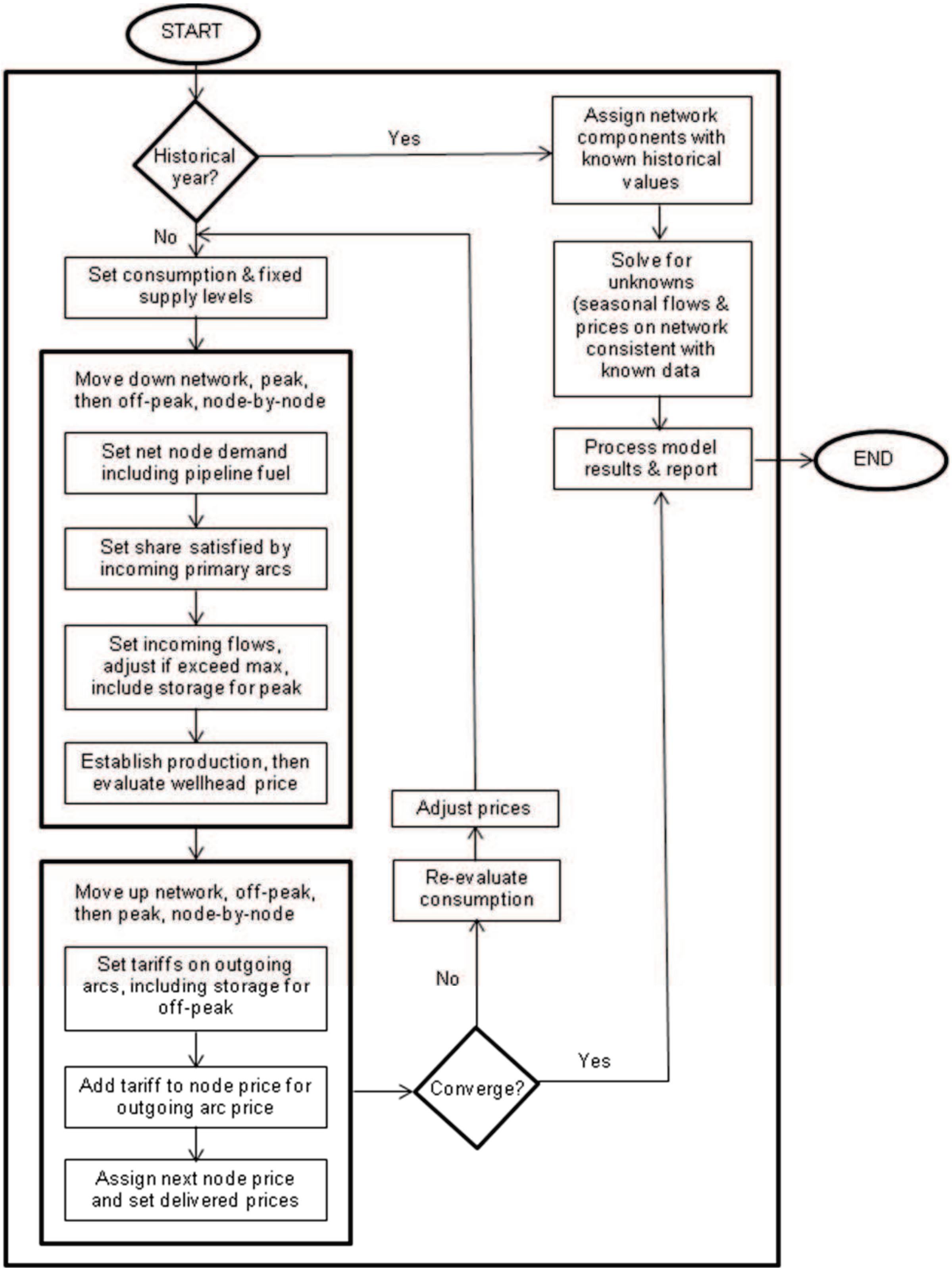
$$\begin{aligned} NODE\_DMD_{PK,r} &= PFUEL_{PK,r} + FLOW_{PK,a} + NODE\_CDMD_{PK,r} \\ &\sum_{nonu} (PKSHR\_DMD_{nonu,r} * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \\ &\sum_{jutil \subset r} (PKSHR\_UDMD_{jutil} * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil}) \end{aligned} \quad (55)$$

$$\begin{aligned} NODE\_CDMD_{PK,r} = {} & YEAR\_CDMD_{PK,r} - (PKSHR\_PROD_s * ZADGPRD_s) - \\ & (PKSHR\_ILNG * OGQNGIMP_{L,t}) \end{aligned} \quad (56)$$

$$\begin{aligned} YEAR\_CDMD_{PK,r} = {} & DISCR_{PK,r,t} + CN\_DISCR_{PK,cn} \\ & ((PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\ & (PK1 * SAFLOW_{a,t}) - (PK2 * SAFLOW_{a',t}) - \\ & (PKSHR\_YR * QAK\_ALB_t) - (PKSHR\_SUPLM * ZTOTSUP_r) - \\ & (PKSHR\_PROD_s * CN\_FIXSUP_{cn,t}) \end{aligned} \quad (57)$$

[57] The model typically solves within 3 to 6 cycles.

Figure 4-3. Interstate Transmission Submodule System



Off-Peak:

$$NODE\_DMD_{OP,r} = PFUEL_{OP,r} + FLOW_{OP,a} + FLOW_{PK,st} + NODE\_CDMD_{OP,r} + \sum_{nonu}((1 - PKSHR\_DMD_{nonu,r}) * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \sum_{jutil \subset r}((1 - PKSHR\_UDMD_{jutil}) * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil})) + \quad (58)$$

$$NODE\_CDMD_{OP,r} = YEAR\_CDMD_{OP,r} - ((1 - PKSHR\_PROD_s) * ZADGPRD_s) - ((1 - PKSHR\_ILNG) * OGQNGIMP_{L,t}) \quad (59)$$

$$\begin{aligned} YEAR\_CDMD_{OP,r} = {} & DISCR_{OP,r,t} + CN\_DISCR_{OP,cn} + \\ & ((1 - PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\ & ((1 - PK1) * SAFLOW_{a,t}) - ((1 - PK2) * SAFLOW_{a',t}) - \\ & ((1 - PKSHR\_YR) * QAK\_ALB_t) - \\ & ((1 - PKSHR\_SUPLM) * ZTOTSUP_r) - \\ & ((1 - PKSHR\_PROD_s) * CN\_FIXSUP_{cn,t}) \end{aligned} \quad (60)$$

where,

$NODE\_DMD_{n,r}$	=	net node demands in region r, for network n (Bcf)
$NODE\_CDMD_{n,r}$	=	net node demands remaining constant each NEMS iteration in region r, for network n (Bcf)
$YEAR\_CDMD_{n,r}$	=	net node demands remaining constant within a forecast year in region r, for network n (Bcf)
$PFUEL_{n,r}$	=	Pipeline fuel consumption in region r, for network n (Bcf)
$FLOW_{n,a}$	=	Seasonal flow on network n, along arc a [out of region r] (Bcf)
$ZNGQTY\_F_{nonu,r}$	=	Core demands in region r, by nonelectric sectors nonu (Bcf)
$ZNGQTY\_I_{nonu,r}$	=	Noncore demands in region r, by nonelectric sectors nonu(Bcf)
$ZNGUQTY\_F_{jutil}$	=	Core utility demands in NGTDM/EMM subregion jutil [subset of region r] (Bcf)
$ZNGUQTY\_I_{jutil}$	=	Noncore utility demands in NGTDM/EMM subregion jutil [subset of region r] (Bcf)
$ZADGPRD_s$	=	Onshore and offshore associated-dissolved gas production in supply subregion s (Bcf)
$DISCR_{n,r,t}$	=	Lower 48 discrepancy in region r, for network n, in forecast year t (Bcf)[58]

[58]Projected lower 48 discrepancies are primarily based on the average historical level from 1990 to 2009. Discrepancies are adjusted in the STEO years to account for STEO discrepancy (Appendix E, STDISCR) and annual net storage withdrawal

$CN\_DISCR_{n,cn}$ = Canada discrepancy in Canadian region cn, for network n (Bcf)
$CN\_DMD_{cn,t}$ = Canada demand in Canadian region cn, in forecast year t (Bcf, Appendix E)
$SAFLOW_{a,t}$ = Secondary flows out of region r, along arc a [includes Canadian and Mexican exports, Canadian gas that flows through the U.S., and lower 48 bidirectional flows] (Bcf)
$SAFLOW_{a',t}$ = Secondary flows into region r, along arc a' [includes Mexican imports, Canadian imports into the East North Central Census Division, Canadian gas that flows through the U.S., and lower 48 bidirectional flows] (Bcf)
QAK_ALB_t = Natural gas flow from Alaska into Alberta via pipeline (Bcf)
$ZTOTSUP_r$ = Total supply from SNG liquids, SNG coal, and other supplemental in forecast year t (Bcf)
$OGQNGIMP_{L,t}$ = LNG imports from LNG region L, in forecast year t (Bcf)
$CN\_FIXSUP_{cn,t}$ = Fixed supply from Canadian region cn, in forecast year t (Bcf, Appendix E)
PK1, PK2 = Fraction of either in-flow or out-flow volumes corresponding to peak season (composed of PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, or PKSHR_YR)
$PKSHR\_DMD_{nonu,r}$ = Average (2001-2009) fraction of annual consumption in each nonelectric sector in region r corresponding to the peak season
$PKSHR\_UDMD_{jutil}$ = Average (1994-2009, except New England 1997-2009) fraction of annual consumption in the electric generator sector in region r corresponding to the peak season
$PKSHR\_PROD_s$ = Average (1994-2009) fraction of annual production in supply region s corresponding to the peak season (fraction, Appendix E)
PKSHR_CDMD = Fraction of annual Canadian demand corresponding to the peak season (fraction, Appendix E)
PKSHR_YR = Fraction of the year represented by the peak season
PKSHR_SUPLM = Average (1990-2009) fraction of supplemental supply corresponding to the peak season
PKSHR_ILNG = Fraction of LNG imports corresponding to the peak season
PKSHR_ECAN = Fraction of Canadian exports transferred in peak season
PKSHR_ICAN = Fraction of Canadian imports transferred in peak season
PKSHR_EMEX = Fraction of Mexican exports transferred in peak season
PKSHR_IMEX = Fraction of Mexican imports transferred in peak season
r = region/node
n = network (peak or off-peak)
PK,OP = Peak and off-peak network, respectively
nonu = Nonelectric sector ID: residential, commercial, industrial, transportation
jutil = Utility sector subregion ID in region r
a,a' = Arc ID for arc entering (a') or exiting (a) region r

(Appendix E, NNETWITH) forecasts, and differences between NEMS and STEO total consumption levels Appendix E, STENDCON). These adjustments are phased out over a user-specified number of years (Appendix E, STPHAS_YR).

s = Supply subregion ID into region r (1-21)
cn = Canadian supply subregion ID in region r (1-2)
L = LNG import region ID into region r (1-12)
st = Arc ID corresponding to storage supply into region r
t = Current forecast year

Pipeline Fuel Use and Intraregional Flows

Pipeline fuel consumption represents the natural gas consumed by compressors to transmit gas along pipelines within a region. In the ITS, pipeline fuel consumption is modeled as a regional demand component. It is estimated for each region on each network using a historically based factor, corresponding net demands, and a multiplicative scaling factor. The scaling factor is used to calibrate the results to equal the most recent national *Short-Term Energy Outlook (STEO)* forecast[59] for pipeline fuel consumption (Appendix E, STQGPTR), net of pipeline fuel consumption in Alaska (QALK_PIP), and is phased out by a user-specified year (Appendix E, STPHAS_YR). The following equation applies:

$$PFUEL_{n,r} = PFUEL\_FAC_{n,r} * NODE\_DMD_{n,r} * SCALE\_PF \tag{61}$$

where,

$PFUEL_{n,r}$ = Pipeline fuel consumption in region r, for network n (Bcf)
$PFUEL\_FAC_{n,r}$ = Average (2004-2009) historical pipeline fuel factor in region r, for network n (calculated historically for each region as equal PFUEL/NODE_DMD)
$NODE\_DMD_{n,r}$ = Net demands (excluding pipeline fuel) in region r, for network n (Bcf)
SCALE_PF = STEO benchmark factor for pipeline fuel consumption
n = network (peak and off-peak)
r = region/node

After pipeline fuel consumption is calculated for each node on the network, the regional/seasonal value is added to net demand at the respective node. Flows into a node ($FLOW_{n,a}$) are then defined using net demands and a sharing algorithm (described below). The regional pipeline fuel quantity (net of intraregional pipeline fuel consumption) [60] is distributed over the pipeline arcs entering the region. This is accomplished by sharing the net pipeline fuel quantity over all of the interregional pipeline arcs entering the region, based on their relative levels of natural gas flow:

[59]EIA produces a separate quarterly forecast for primary national energy statistics over the next several years. For certain forecast items, the NEMS is calibrated to produce an equivalent (within 2 to 5 percent) result for these years. For *AEO2011*, the years calibrated to *STEO* results were 2010 and 2011.

[60]Currently, intraregional pipeline fuel consumption (INTRA_PFUEL) is set equal to the regional pipeline fuel consumption level (PFUEL); therefore, pipeline fuel consumption along an arc (ARC_PFUEL) is set to zero. The original design was to allocate pipeline fuel according to flow levels on arcs and within a region. It was later determined that assigning all of the pipeline fuel to a region would simplify benchmarking the results to the STEO and would not change the later calculation of the price impacts of pipeline fuel use.

$$ARC\_PFUEL_{n,a} = (PFUEL_{n,r} - INTRA\_PFUEL_{n,r}) * \frac{FLOW_{n,a}}{TFLOW} \qquad (62)$$

where,

$ARC\_PFUEL_{n,a}$	=	Pipeline fuel consumption along arc a (into region r), for network n (Bcf)
$PFUEL_{n,r}$	=	Pipeline fuel consumption in region r, for network n (Bcf)
$INTRA\_PFUEL_{n,r}$	=	Intraregional pipeline fuel consumption in region r, for network n (Bcf)
$FLOW_{n,a}$	=	Interregional pipeline flow along arc a (into region r), for network n (Bcf)
TFLOW	=	Total interregional pipeline flow [into region r] (Bcf)
n	=	network (peak and off-peak)
r	=	region/node
a	=	arc

Pipeline fuel consumption along an interregional arc and within a region on an intrastate pipeline will have an impact on pipeline tariffs and node prices. This will be discussed later in the Arc, Node, and Storage Prices subsection.

The flows of natural gas on the interstate pipeline system within each NGTDM region (as opposed to between two NGTDM regions) are established for the purpose of setting the associated revenue requirements and tariffs. The charge for moving gas within a region (INTRAREG_TAR), but on the interstate pipeline system, is taken into account when setting city gate prices, described below. The algorithm for setting intraregional flows is similar to the method used for setting pipeline fuel consumption. For each region in the historical years, a factor is calculated reflective of the relationship between the net node demand and the intraregional flow. This factor is applied to the net node demand in each forecast year to approximate the associated intraregional flow. Pipeline fuel consumption is excluded from the net node demand for this calculation, as follows:

Calculation of intraregional flow factor based on data for an historical year:

$$FLO\_FAC_{n,r} = INTRA\_FLO_{n,r} \;/\; (NODE\_DMD_{n,r} - PFUEL_{n,r}) \qquad (63)$$

Forecast of intraregional flow:

$$INTRA\_FLO_{n,r} = FLO\_FAC_{n,r} * (NODE\_DMD_{n,r} - PFUEL_{n,r}) \qquad (64)$$

where,

$INTRA\_FLO_{n,a}$	=	Intraregional, interstate pipeline flow within region r, for network n (Bcf)
$PFUEL_{n,r}$	=	Pipeline fuel consumption in region r, for network n (Bcf)
$NODE\_DMD_{n,r}$	=	Net demands (with pipeline fuel) in region r, for network n (Bcf)

$FLO\_FAC_{n,r}$ = Average (1990 - 2009) historical relationship between net node demand and intraregional flow
n = network (peak and off-peak)
r = region/node

Historical annual intraregional flows are set for the peak and off-peak periods based on the peak and off-peak share of net node demand in each region.

Sharing Algorithm, Flows, and Capacity Expansion

Moving systematically downward from node to node through the acyclic network, the sharing algorithm is allocates net demands ($NODE\_DMD_{n,r}$) across all arcs feeding into the node. These "inflow" arcs carry flows from local supply sources, storage (net withdrawals during peak period only), or other regions (interregional arcs). If any of the resulting flows exceed their corresponding maximum levels,[61] then the excess flows are reallocated to the unconstrained arcs, and new shares are calculated accordingly. At each node within a network, the sharing algorithm determines the percent of net demand ($SHR_{n,a,t}$) that is satisfied by each of the arcs entering the region.

The sharing algorithm (shown below) dictates that the share ($SHR_{n,a,t}$) of demand for one arc into a node is a function of the share defined in the previous model year[62] and the ratio of the price on the one arc relative to the average of the prices on all of the arcs into the node, as defined the previous cycle up the network tree. These prices ($ARC\_SHRPR_{n,a}$) represents the unit cost associated with an arc going into a node, and is defined as the sum of the unit cost at the source node ($NODE\_SHRPR_{n,r}$) *and* the tariff charge along the arc ($ARC\_SHRFEE_{n,a}$). (A description of how these components are developed is presented later.) The variable γ is an assumed parameter that is always positive. This parameter can be used to prevent (or control) broad shifts in flow patterns from one forecast year to the next. Larger values of γ increase the sensitivity of $SHR_{n,a,t}$ to relative prices; a very large value of γ would result in behavior equivalent to cost minimization. The algorithm is presented below:

$$SHR_{n,a,t} = \frac{ARC\_SHRPR_{n,a}^{-\gamma}}{\frac{\sum_{b} ARC\_SHRPR_{n,b}^{-\gamma}}{N}} * SHR_{n,a,t-1} \qquad (65)$$

where,

$SHR_{n,a,t}$, $SHR_{n,a,t-1}$ = The fraction of demand represented along inflow arc a on network n, in year t (or year t-1) [Note: The value for year t-1 has a lower limit set to 0.01]

[61]Maximum flows include potential pipeline or storage capacity additions, and maximum production levels.
[62]When planned pipeline capacity is added at the beginning of a forecast year, the value of SHR_{t-1} is adjusted to reflect a percent usage (PCTADJSHR, Appendix E) of the new capacity. This adjustment is based on the assumption that last year's share would have been higher if not constrained by the existing capacity levels.

$ARC\_SHRPR_{n,a\ or\ b}$	=	The last price calculated for natural gas from inflow arc a (or b) on network n [i.e., from the previous cycle while moving up the network] (87$/Mcf)
N	=	Total number of arcs into a node
γ	=	Coefficient defining degree of influence of relative prices (represented as GAMMAFAC, Appendix E)
t	=	forecast year
n	=	network (peak or off-peak)
a	=	arc into a region
r	=	region/node
b	=	set of arcs into a region

[Note: The resulting shares ($SHR_{n,a,t}$) along arcs going into a node are then normalized to ensure that they add to one.]

Seasonal flows are generated for each arc using the resulting shares and net node demands, as follows:

$$FLOW_{n,a} = SHR_{n,a,t} * NODE\_DMD_{n,r} \quad (66)$$

where,

$FLOW_{n,a}$	=	Interregional flow (into region r) along arc a, for network n (Bcf)
$SHR_{n,a,t}$	=	The fraction of demand represented along inflow arc a on network n, in year t
$NODE\_DMD_{n,r}$	=	Net node demands in region r, for network n (Bcf)
n	=	network (peak or off-peak)
a	=	arc into a region
r	=	region/node

These flows must not exceed the maximum flow limits ($MAXFLO_{n,a}$) defined for each arc on each network. The algorithm used to define maximum flows may differ depending on the type of arc (storage, pipeline, supply, Canadian imports) and the network being referenced. For example, maximum flows for all *peak* network arcs are a function of the maximum permissible annual capacity levels ($MAXPCAP_{PK,a}$) and peak utilization factors. However, maximum *pipeline* flows along the *off-peak* network arcs are a function of the annual capacity defined by peak flows and off-peak utilization factors. Thus, maximum flows along the off-peak network depend on whether or not capacity was added during the peak period. Also, maximum flows from *supply* sources in the off-peak network are limited by maximum annual capacity levels and off-peak utilization. (Note: *storage* arcs do not enter nodes on the off-peak network; therefore, maximum flows are not defined there.) The following equations define maximum flow limits and maximum annual capacity limits:

Maximum peak flows (note: for storage arcs, PKSHR_YR=1):

$$MAXFLO_{PK,a} = MAXPCAP_{PK,a} * (PKSHR\_YR * PKUTZ_a) \quad (67)$$

with $MAXPCAP_{PK,a}$ defined by type as follows:

for *Supply*[63]:

$$MAXPCAP_{PK,a} = ZOGRESNG_s * ZOGPRRNG_s * MAXPRRFAC * (1 - (PCTLP_r * SCALE\_LP_t)) \tag{68}$$

for *Pipeline*:

$$MAXPCAP_{PK,a} = PTMAXPCAP_{i,j} \tag{69}$$

for *Storage*:

$$MAXPCAP_{PK,a} = PTMAXPSTR_{st} \tag{70}$$

for *Canadian imports*:

$$MAXPCAP_{PK,a} = CURPCAP_{a,t} \tag{71}$$

Maximum off-peak pipeline flows:

$$MAXFLO_{OP,a} = MAXPCAP_{OP,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \tag{72}$$

with $MAXPCAP_{OP,a}$ is defined as follows for

either *current capacity:*

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} \tag{73}$$

or *current capacity* plus *capacity additions*,

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} + ((1 + XBLD) * \left(\frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} - CURPCAP_{a,t}\right)) \tag{74}$$

or, for *pipeline arc entering region 10 (Florida), peak maximum capacity*,

$$MAXPCAP_{OP,a} = MAXPCAP_{PK,a} \tag{75}$$

[63] In historical years, historical production values are used in place of the product of ZOGRESNG and ZOGPRRNG.

Maximum off-peak flows from supply sources:

$$MAXFLO_{OP,a} = MAXPCAP_{PK,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \tag{76}$$

where,

$MAXFLO_{n,a}$	=	Maximum flow on arc a, in network n [PK-peak or OP-off-peak] (Bcf)
$MAXPCAP_{n,a}$	=	Maximum annual physical capacity along arc a for network n (Bcf)
$CURPCAP_{a,t}$	=	Current annual physical capacity along arc a in year t (Bcf)
$ZOGRESNG_s$	=	Natural gas reserve levels for supply source s [defined by OGSM] (Bcf)
$ZOGPRRNG_s$	=	Expected natural gas production-to-reserves ratio for supply source s [defined by OGSM] (fraction)
MAXPRRFAC	=	Factor to set maximum production-to-reserves ratio [MAXPRRCAN for Canada] (Appendix E)
$PCTLP_t$	=	Average (1996-2009) fraction of production consumed as lease and plant fuel in forecast year t
$SCALE\_LP_t$	=	Scale factor for STEO year percent lease and plant consumption for forecast year t to force regional lease and plant consumption forecast to total to STEO forecast.
$PTMAXPCAP_{i,j}$	=	Maximum pipeline capacity along arc defined by source node i and destination node j [defined by PTS] (Bcf)
$PTMAXPSTR_{st}$	=	Maximum storage capacity for storage source st [defined by PTS] (Bcf)
$FLOW_{PK,a}$	=	Flow along arc a for the peak network (Bcf)
PKSHR_YR	=	Fraction of the year represented by peak season
$PKUTZ_a$	=	Pipeline utilization along arc a for the peak season (fraction, Appendix E)
$OPUTZ_a$	=	Pipeline utilization along arc a for the off-peak season (fraction, Appendix E)
XBLD	=	Percent increase over capacity builds to account for weather (fraction, Appendix E)
a	=	arc
t	=	forecast year
n	=	network (peak or off-peak)
PK, OP	=	peak and off-peak network, respectively
s,st	=	supply or storage source
i,j	=	regional source (i) and destination (j) link on arc a

If the model has been restricted from building capacity through a specified forecast year (Appendix E, NOBLDYR), then the maximum pipeline and storage flow for either network will be based only on current capacity and utilization for that year.

If the flows defined by the sharing algorithm above exceed these maximum levels, then the excess flow is reallocated along adjacent arcs that have excess capacity. This is achieved by determining the flow distribution of the qualifying adjacent arcs, and distributing the excess flow according to this distribution. These adjacent arcs are checked again for excess flow; if excess flow is found, the reallocation process is performed again on all arcs with space remaining. This applies to supply and pipeline arcs on all networks, as well as storage withdrawal arcs on the peak network. To handle the event where insufficient space or supply is available on all inflowing arcs to meet demand, a backstop supply ($BKSTOP_{n,r}$) is available at an incremental price ($RBKSTOP\_PADJ_{n,r}$). The intent is to dissuade use of the particular route, or to potentially lower demands. Backstop pricing will be defined in another section below.

With the exception of import and export arcs,[64] the resulting interregional flows defined by the sharing algorithm for the peak network are used to determine if *pipeline* capacity expansion should occur. Similarly, the resulting storage withdrawal quantities in the peak season define the *storage* capacity expansion levels. Thus, initially capacity expansion is represented by the difference between new capacity levels ($ACTPCAP_a$) and current capacity ($CURPCAP_{a,t}$, previous model year capacity plus planned additions). In the module, these initial new capacity levels are defined as follows:

Storage:

$$ACTPCAP_a = \frac{FLOW_{PK,a}}{PKUTZ_a} \tag{77}$$

Pipeline:

$$ACTPCAP_a = MAXPCAP_{OP,a} \tag{78}$$

Pipeline arc entering region 10 (Florida):

$$ACTPCAP_a = \text{MAX between } \frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} \text{ and } \frac{FLOW_{OP,a}}{(1 - PKSHR\_YR) * OPUTZ_a} \tag{79}$$

where,

$ACTPCAP_a$	=	Annual physical capacity along an arc a (Bcf)
$MAXPCAP_{OP,a}$	=	Maximum annual physical capacity along pipeline arc a for network n [see equation above] (Bcf)
$FLOW_{n,a}$	=	Flow along arc a on network n (Bcf)
$PKUTZ_a$	=	Maximum peak utilization of capacity along arc a (fraction, Appendix E)
$OPUTZ_a$	=	Maximum off-peak utilization of capacity along arc a (fraction, Appendix E)
PKSHR_YR	=	Fraction of the year represented by the peak season
a	=	pipeline and storage arc
n	=	network (peak or off-peak)

[64]For *AEO2011* capacity expansion on Canadian import arcs were set exogenously (PLANPCAP, Appendix E).

PK = peak season
OP = off-peak season

A second check and potential adjustment are made to these capacity levels to insure that capacity is sufficient to handle estimated flow in the peak month of each period.[65] Since capacity is defined as sustained capacity, it is assumed that the peak month flows should be in accordance with the maximum capacity requirements of the system, short of line packing, propane injections, and planning for the potential of above average temperature months.[66] Peak month consumption and supply levels are set at an assumed fraction of the corresponding period levels. Based on historical relationships, an initial guess is made at the fraction of each period's net storage withdrawals removed during the peak month. With this information, peak month flows are set at the same time flows are set for each period, while coming down the network tree, and following a similar process. At each node a net monthly demand is set equal to the sum of the monthly flows going out of the node, plus the monthly consumption at the node, minus the monthly supply and net storage withdrawals. The period shares are then used to set initial monthly flows, as follows:

$$MTHFLW_{n,a} = MTH\_NETNOD_{n,r} * \frac{SHR_{n,a,t}}{\sum_{c} SHR_{n,c,t}} \tag{80}$$

where,

$MTHFLW_{n,a}$ = Monthly flow along pipeline arc a (Bcf)
$MTH\_NETNOD_{n,r}$ = Monthly net demand at node r (Bcf)
$SHR_{n,a,t}$ = Fraction of demand represented along inflow arc a
c = set of arcs into a region representing pipeline arcs
n = network (peak or off-peak)
a = arc into a region
r = region/node
t = forecast year

These monthly flows are then compared against a monthly capacity estimate for each pipeline arc and reallocated to the other available arcs if capacity is exceeded, using a method similar to what is done when flows for a period exceed maximum capacity. These adjusted monthly flows are used later in defining the net node demand for nodes lower in the network tree. Monthly capacity is estimated by starting with the previously set ACTPCAP for the pipeline arc divided by the number of months in the year, to arrive at an initial monthly capacity estimate (MTH_CAP). This number is increased if the total of the monthly capacity entering a node exceeds the monthly net node demand, as follows:

$$MTH\_CAPADD_{n,a} = MTH\_TCAPADD_{n} * \frac{INIT\_CAPADD_{n,a}}{\sum_{c} INIT\_CAPADD_{n,c}} \tag{81}$$

[65]Currently this is only done in the model for the peak period of the year.
[66]To represent that the pipeline system is built to accommodate consumption levels outside the normal range due to colder than normal temperatures, the net monthly demand levels are increased by an assumed percentage (XBLD, Appendix E).

where,

$MTH\_CAPADD_{n,a}$ = Additional added monthly capacity to accommodate monthly flow estimates (Bcf)

$MTH\_TCAPADD_{n}$ = Total initial monthly capacity entering a node minus monthly net node demand (Bcf), if value is negative then it is set to zero

$INIT\_CAPADD_{n,a}$ = MTHFLWa - MTH_CAPa, if value is negative then it is set to zero (Bcf)

n = network (peak or off-peak)

a = arc into a region

c = set of arcs into a region representing pipeline arcs

The additional added monthly capacity is multiplied by the number of months in the year and added to the originally estimated pipeline capacity levels for each arc (ACTPCAP). Finally, if the net node demand is not close to zero at the lowest node on the network tree (node number 24 in western Canada), then monthly storage levels are adjusted proportionally throughout the network to balance the system for the next time quantities are brought down the network tree.

Wellhead and Henry Hub Prices

Ultimately, all of the network-specific consumption levels are transferred down the network trees and into supply nodes, where corresponding supply prices are calculated. The Oil and Gas Supply Module (OGSM) provides only annual price/quantity supply curve parameters for each supply subregion. Because this alone will not provide a wellhead price differential between seasons, a special methodology has been developed to approximate seasonal prices that are consistent with the annual supply curve. First, in effect the quantity axis of the annual supply curve is scaled to correspond to seasonal volumes (based on the period's share of the year); and the resulting curves are used to approximate seasonal prices. (Operationally within the model this is done by converting seasonal production values to annual equivalents and applying these volumes to the annual supply curve to arrive at seasonal prices.) Finally, the resulting seasonal prices are scaled to ensure that the quantity-weighted average annual wellhead price equals the price obtained from the annual supply curve when evaluated using total annual production. To obtain seasonal wellhead prices, the following methodology is used. Taking one supply region at a time, the model estimates equivalent annual production levels (ANNSUP) for each season.

Peak:

$$ANNSUP = \frac{NODE\_QSUP_{PK,s}}{PKSHR\_YR} \tag{82}$$

Off-peak:

$$ANNSUP = \frac{NODE\_QSUP_{OP,s}}{(1 - PKSHR\_YR)} \tag{83}$$

where,

ANNSUP = Equivalent annual production level (Bcf)

$NODE\_QSUP_{n,s}$ = Seasonal (n=PK-peak or OP-off-peak) production level for supply region s (Bcf)

PKSHR_YR = Fraction of year represented by peak season
PK = peak season
OP = off-peak season
s = supply region

Next, estimated seasonal prices ($SPSUP_n$) are obtained using these equivalent annual production levels and the annual supply curve function. These initial seasonal prices are then averaged, using quantity weights, to generate an equivalent *average* annual supply price ($SPAVG_s$). An *actual* annual price ($PSUP_s$) is also generated, by evaluating the price on the annual supply function for a quantity equal to the sum of the seasonal production levels. The *average* annual supply price is then compared to the *actual* price. The corresponding ratio (FSF) is used to adjust the estimated seasonal prices to generate final seasonal supply prices ($NODE\_PSUP_{n,s}$) for a region.

For a *supply source* s,

$$FSF = \frac{PSUP_s}{SPAVG_s} \tag{84}$$

and,

$$NODE\_PSUP_{n,s} = SPSUP_n * FSF \tag{85}$$

where,

FSF = Scaling factor for seasonal prices
$PSUP_s$ = Annual supply price from the annual supply curve for supply region s (87$/Mcf)
$SPAVG_s$ = Quantity-weighted average annual supply price using peak and off-peak prices and production levels for supply region s (87$/Mcf)
$NODE\_PSUP_{n,s}$ = Adjusted seasonal supply prices for supply region s (87$/Mcf)
$SPSUP_n$ = Estimated seasonal supply prices [for supply region s] (87$/Mcf)
n = network (peak or off-peak)
s = supply source

During the STEO years (2010 and 2011 for *AEO2011*), national average wellhead prices (lower 48 only) generated by the model are compared to the national STEO wellhead price forecast to generate a benchmark factor ($SCALE\_WPR_t$). This factor is used to adjust the regional (annual and seasonal) lower 48 wellhead prices to equal STEO results. This benchmark factor is only applied for the STEO years. The benchmark factor is applied as follows:

Annual:

$$PSUP_s = PSUP_s * SCALE\_WPR_t \tag{86}$$

Seasonal:

$$NODE\_PSUP_{n,s} = NODE\_PSUP_{n,s} * SCALE\_WPR_t \tag{87}$$

where,

$PSUP_s$ = Annual supply price from the annual supply curve for supply region s (87$/Mcf)
$NODE\_PSUP_{n,s}$ = Adjusted seasonal supply prices for supply region s (87$/Mcf)
$SCALE\_WPR_t$ = STEO benchmark factor for wellhead price in year t
n = network (peak or off-peak)
s = supply source
t = forecast year

A similar adjustment is made for the Canadian supply price, with an additional multiplicative factor applied (STSCAL_CAN, Appendix E) which is set to align Canadian import levels with STEO results.

While the NGTDM does not explicitly represent the Henry Hub within its modeling structure, the module reports a projected value for reporting purposes. The price at the Henry Hub is set using an econometrically estimated equation as a function of the lower 48 average natural gas wellhead price, as follows:

$$oOGHHPRNG_t = 1.00439 * e^{0.090246} * oOGWPRNG_{s=13,t}^{1.00119} \tag{88}$$

where,

$oOGHHPRNG_t$ = Natural gas price at the Henry Hub (87$/MMBtu)
$oOGWPRNG_{s,t}$ = Average natural gas wellhead price for supply region 13, representing the lower 48 average (87$/Mcf)
s = supply source/region
t = forecast year

Details about the generation of this estimated equation and associated parameters are provided in **Table F9**, Appendix F.

Arc Fees (Tariffs)

Fees (or tariffs) along arcs are used in conjunction with supply, storage, and node prices to determine competing arc prices that, in turn, are used to determine network flows, transshipment node prices, and delivered prices. Arc fees exist in the form of pipeline tariffs, storage fees, and gathering charges. Pipeline tariffs are transportation rates along interregional arcs, and reflect the average rate charged over all of the pipelines represented along an arc. Storage fees represent the charges applied for storing, injecting, and withdrawing natural gas that is injected in the off-peak period for use in the peak period, and are applied along arcs connecting the storage sites to the peak network. Gathering charges are applied to the arcs going from the supply points to the transshipment nodes.

Pipeline and storage tariffs consist of both a fixed (volume independent) term and a variable (volume dependent) term. For pipelines the fixed term ($ARC\_FIXTAR_{n,a,t}$) is set in the PTS at the beginning of each forecast year to represent pipeline usage fees and does not vary in response to changes in flow in the current year. For storage, the fixed term establishes a minimum and is set to $0.001 per Mcf. The variable term is obtained from tariff/capacity curves provided by two PTS functions and represents reservation fees for pipelines and all charges for storage. These two functions are NGPIPE_VARTAR and X1NGSTR_VARTAR. When determining network flows a different set of tariffs ($ARC_SHRFEE_{n,a}$) are used than are used when setting delivered prices ($ARC_ENDFEE_{n,a}$).

In the peak period ARC_SHRFEE equals ARC_ENDFEE and the total tariff (reservation plus usage fee). In the off-peak period, ARC_ENDFEE represents the total tariff as well, but ARC_SHRFEE represents the fee that drives the flow decision. In previous AEOs this was set to just the usage fee. The assumption behind this structure was that delivered prices will ultimately reflect reservation charges, but that during the off-peak period in particular, decisions regarding the purchase and transport of gas are made largely independently of where pipeline is reserved and the associated fees. For *AEO2011* the ARC_SHRFEE was set similarly to ARC_ENDFEE because the usage fees seemed to be underestimating off-peak market prices. (This decision will be reexamined in the future.) During the peak period, the gas is more likely to flow along routes where pipeline is reserved; therefore the flow decision is more greatly influenced by the relative reservation fees.[67] The following arc tariff equations apply:

Pipeline:

$$\begin{aligned} ARC\_ENDFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n,a,i,j,FLOW_{n,a}) \\ ARC\_SHRFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n,a,i,j,FLOW_{n,a}) \end{aligned} \tag{89}$$

Storage:

$$\begin{aligned} ARC\_SHRFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + X1NGSTR\_VARTAR(st,FLOW_{n,a}) \\ ARC\_ENDFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + X1NGSTR\_VARTAR(st,FLOW_{n,a}) \end{aligned} \tag{90}$$

where,

$ARC\_SHRFEE_{n,a}$	=	Total arc fees along arc a for network n [used with sharing algorithm] (87$/Mcf)
$ARC\_ENDFEE_{n,a}$	=	Total arc fees along arc a for network n [used with delivered pricing] (87$/Mcf)
$ARC\_FIXTAR_{n,a,t}$	=	Fixed (or usage) fees along an arc a for a network n in time t (87$/Mcf)
NGPIPE_VARTAR	=	PTS function to define pipeline tariffs representing reservation fees for specified arc at given flow level
X1NGSTR_VARTAR	=	PTS function to define storage fees at specified storage region for given storage level

[67]Reservation fees are frequently considered "sunk" costs and are not expected to influence short-term purchasing decisions as much, but still must ultimately be paid by the end-user. Therefore within the ITS, the arc prices used in determining flows can have tariff components defined differently than their counterparts (arc and node prices) ultimately used to establish delivered prices.

$FLOW_{n,a}$ = Flow of natural gas on the arc in the given period
n = network (peak or off-peak)
a = arc
i, j = from transshipment node i to transshipment node j

A methodology for defining gathering charges has not been developed but may be developed in a separate effort at a later date.[68] In order to accommodate this, the supply arc indices in the variable $ARC\_FIXTAR_{n,a}$ have been reserved for this information (currently set to 0). Since the historical wellhead price represents a first-purchase price, the cost of gathering is frequently already included and no further charge should be added.

Arc, Node, and Storage Prices

Prices at the transshipment nodes (or node prices) represent intermediate prices that are used to determine regional delivered prices. Node prices (along with tariffs) are also used to help make model decisions, primarily within the flow-sharing algorithm. In both cases it is not required (as described above) to set delivered or arc prices using the same price components or methods used to define prices needed to establish flows along the networks (e.g., in setting $ARC\_SHRPR_{n,a}$ in the share equation). Thus, *process-specific* node prices ($NODE\_ENDPR_{n,r}$ and $NODE\_SHRPR_{n,r}$) are generated using *process-specific* arc prices ($ARC\_ENDPR_{n,a}$ and $ARC\_SHRPR_{n,a}$) which, in turn, are generated using *process-specific* arc fees/tariffs ($ARC\_ENDFEE_{n,a}$ and $ARC\_SHRFEE_{n,a}$).

The following equations define the methodology used to calculate arc prices. Arc prices are first defined as the average node price at the source node plus the arc fee (pipeline tariff, storage fee, or gathering charge). Next, the arc prices along pipeline arcs are adjusted to account for the cost of pipeline fuel consumption. These equations are as follows:

$$\begin{aligned} ARC\_SHRPR_{n,a} &= NODE\_SHRPR_{n,rs} + ARC\_SHRFEE_{n,a} \\ ARC\_ENDPR_{n,a} &= NODE\_ENDPR_{n,rs} + ARC\_ENDFEE_{n,a} \end{aligned} \tag{91}$$

with the adjustment accomplished through the assignment statements:

$$\begin{aligned} ARC\_SHRPR_{n,a} &= \frac{(ARC\_SHRPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})} \\ ARC\_ENDPR_{n,a} &= \frac{(ARC\_ENDPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})} \end{aligned} \tag{92}$$

[68] In a previous version of the NGTDM, "gathering" charges were used to benchmark the regional wellhead prices to historical values. It is possible that they may be used (at least in part) to fulfill the same purpose in the ITS. In the past an effort was made, with little success, to derive representative gathering charges. Currently, the gathering charge portion of the tariff along the supply arcs is assumed to be zero.

where,

$ARC\_SHRPR_{n,a}$	=	Price calculated for natural gas along inflow arc a for network n [used with sharing algorithm] (87$/Mcf)
$ARC\_ENDPR_{n,a}$	=	Price calculated for natural gas along inflow arc a for network n [used with delivered pricing] (87$/Mcf)
$NODE\_SHRPR_{n,r}$	=	Node price for region i on network n [used with sharing algorithm] (87$/Mcf)
$NODE\_ENDPR_{n,r}$	=	Node price for region i on network n [used with delivered pricing] (87$/Mcf
$ARC\_SHRFEE_{n,a}$	=	Tariff along inflow arc a for network n [used with sharing algorithm] (87$/Mcf)
$ARC\_ENDFEE_{n,a}$	=	Tariff along inflow arc a for network n [used with delivered pricing] (87$/Mcf)
$ARC\_PFUEL_{n,a}$	=	Pipeline fuel consumption along arc a, for network n (Bcf)
$FLOW_{n,a}$	=	Network n flow along arc a (Bcf)
n	=	network (peak or off-peak)
a	=	arc
rs	=	region corresponding to source link on arc a

Although each type of node price may be calculated differently (e.g., average prices for delivered price calculation, marginal prices for flow sharing calculation, or some combination of these for each), the current model uses the quantity-weighted averaging approach to establish node prices for both the delivered pricing and flow sharing algorithm pricing. Prices from all arcs entering a node are included in the average. Node prices then are adjusted to account for intraregional pipeline fuel consumption. The following equations apply:

$$NODE\_SHRPR_{n,rd} = \frac{\Sigma_a (ARC\_SHRPR_{n,a} * FLOW_{n,a})}{\Sigma_a (FLOW_{n,a} - ARC\_PFUEL_{n,a})}$$

$$NODE\_ENDPR_{n,rd} = \frac{\Sigma_a (ARC\_ENDPR_{n,a} * FLOW_{n,a})}{\Sigma_a (FLOW_{n,a} - ARC\_PFUEL_{n,a})} \tag{93}$$

and,

$$NODE\_SHRPR_{n,rd} = \frac{(NODE\_SHRPR_{n,rd} * NODE\_DMD_{n,rd})}{(NODE\_DMD_{n,rd} - INTRA\_PFUEL_{n,rd})}$$

$$NODE\_ENDPR_{n,rd} = \frac{(NODE\_ENDPR_{n,rd} * NODE\_DMD_{n,rd})}{(NODE\_DMD_{n,rd} - INTRA\_PFUEL_{n,rd})} \tag{94}$$

where,

$NODE\_SHRPR_{n,r}$ = Node price for region r on network n [used with flow sharing algorithm] (87$/Mcf)
$NODE\_ENDPR_{n,r}$ = Node price for region r on network n [used with delivered pricing] (87$/Mcf)
$ARC\_SHRPR_{n,a}$ = Price calculated for natural gas along inflow arc a for network n [used with flow sharing algorithm] (87$/Mcf)
$ARC\_ENDPR_{n,a}$ = Price calculated for natural gas along inflow arc a for network n [used with delivered pricing] (87$/Mcf)
$FLOW_{n,a}$ = Network n flow along arc a (Bcf)
$ARC\_PFUEL_{n,a}$ = Pipeline fuel consumed along the pipeline arc a, network n (Bcf)
$INTRA\_PFUEL_{n,r}$ = Intraregional pipeline fuel consumption in region r, network n (Bcf)
$NODE\_DMD_{n,r}$ = Net node demands (w/ pipeline fuel) in region r, network n (Bcf)
n = network (peak or off-peak)
a = arc
rd = region r destination link along arc a

Once node prices are established for the off-peak network, the cost of the gas injected into storage can be modeled. Thus, for every region where storage is available, the storage node price is set equal to the off-peak regional node price. This applies for both the delivered pricing and the flow sharing algorithm pricing:

$$
\begin{aligned}
NODE\_SHRPR_{PK,i} &= NODE\_SHRPR_{OP,r} \\
NODE\_ENDPR_{PK,i} &= NODE\_ENDPR_{OP,r}
\end{aligned}
\tag{95}
$$

where,

$NODE\_SHRPR_{PK,i}$ = Price at node i [used with flow sharing algorithm] (87$/Mcf)
$NODE\_SHRPR_{OP,r}$ = Price at node r in off-peak network [used with flow sharing algorithm] (87$/Mcf)
$NODE\_ENDPR_{PK,ii}$ = Price at node i [used with delivered pricing] (87$/Mcf)
$NODE\_ENDPR_{OP,r}$ = Price at node r in off-peak network [used with delivered pricing] (87$/Mcf)
PK, OP = peak and off-peak network, respectively
i = node ID for storage
r = region ID where storage exists

Backstop Price Adjustment

Backstop supply[69] is activated when seasonal net demand within a region exceeds total available supply for that region. When backstop occurs, the corresponding *share* node price ($NODE\_SHRPR_{n,r}$) is adjusted upward in an effort to reduce the demand for gas from this

[69]Backstop supply can be thought of as a high-priced alternative supply when no other options are available. Within the model, it also plays an operational role in sending a price signal when equilibrating the network that additional supplies are unavailable along a particular path in the network.

source. If this initial price adjustment ($BKSTOP\_PADJ_{n,r}$) is not sufficient to eliminate backstop, on the next cycle down the network tree, an additional adjustment ($RBKSTOP\_PADJ_{n,r}$) is added to the original adjustment, creating a cumulative price adjustment. This process continues until the backstop quantity is reduced to zero, or until the maximum number of ITS cycles has been completed. If backstop is eliminated, then the cumulative price adjustment level is maintained, as long as backstop does not resurface, and until ITS convergence is achieved. Maintaining a backstop adjustment is necessary because complete removal of this high-price signal would cause demand for this source to increase again, and backstop would return. However, if the need for backstop supply recurs following a cycle which did not need backstop supply, then the price adjustment ($BKSTOP\_PADJ_{n,r}$) factor is reduced by one-half and added to the cumulative adjustment variable, with the process continuing as described above. The objective is to eliminate the need for backstop supply while keeping the associated price at a minimum. The node prices are adjusted as follows:

$$NODE\_SHRPR_{n,r} = NODE\_SHRPR_{n,r} + RBKSTOP\_PADJ_{n,r} \tag{96}$$

$$RBKSTOP\_PADJ_{n,r} = RBKSTOP\_PADJ_{n,r} + BKSTOP\_PADJ_{n,r} \tag{97}$$

where,

$NODE\_SHRPR_{n,r}$	=	Node price for region r on network n [used with flow sharing algorithm] (87$/Mcf)
$RBKSTOP\_PADJ_{n,r}$	=	Cumulative price adjustment due to backstop (87$/Mcf)
$BKSTOP\_PADJ_{n,r}$	=	Incremental backstop price adjustment (87$/Mcf)
n	=	network (peak or off-peak)
r	=	region

Currently, this cumulative backstop adjustment ($RBKSTOP\_PADJ_{n,r}$) is maintained for each NEMS iteration and set to zero only on the first NEMS iteration of each model year. Also, it is not used to adjust the NODE_ENDPR because it is an adjustment for making flow allocation decisions, not for pricing gas for the end-user.

ITS Convergence

The ITS is considered to have converged when the regional/seasonal wellhead prices are within a defined percentage tolerance (PSUP_DELTA) of the prices set during the last ITS cycle and, for those supply regions with relatively small production levels (QSUP_SMALL), production is within a defined tolerance (QSUP_DELTA) of the production set during the last ITS cycle. If convergence does not occur, then a new wellhead price is determined based on a user-specified weighting of the seasonal production levels determined during the current cycle and during the previous cycle down the network. The the new production levels are defined as follows:

$$\begin{aligned} NODE\_QSUP_{n,s} = {} & (QSUP\_WT * NODE\_QSUP_{n,s}) + \\ & ((1 - QSUP\_WT) * NODE\_QSUPPREV_{n,s}) \end{aligned} \tag{98}$$

where,

$NODE\_QSUP_{n,s}$ = Production level at supply source s on network n for current ITS cycle (Bcf)
$NODE\_QSUPPREV_{n,s}$ = Production level at supply source s on network n for previous ITS cycle (Bcf)
$QSUP\_WT$ = Weighting applied to production level for current ITS cycle (Appendix E)
n = network (peak or off-peak)
s = supply source

Seasonal prices ($NODE\_PSUP_{n,s}$) for these quantities are then determined using the same methodology defined above for obtaining wellhead prices.

End-Use Sector Prices

The NGTDM provides regional end-use or delivered prices for the Electricity Market Module (electric generation sector) and the other NEMS demand modules (nonelectric sectors). For the nonelectric sectors (residential, commercial, industrial, and transportation), prices are established at the NGTDM region and then averaged (when necessary) using quantity-weights to obtain prices at the Census Division level. For the electric generation sector, prices are provided on a seasonal basis and are determined for core and noncore services at two different regional levels: the Census Division level and the NGTDM/EMM level (Chapter 2, **Figure 2-3**).

The first step toward generating these delivered prices is to translate regional, seasonal node prices into corresponding city gate prices ($CGPR_{n,r}$). To accomplish this, seasonal intraregional and intrastate tariffs are added to corresponding regional end-use node prices (NODE_ENDPR). This sum is then adjusted using a city gate benchmark factor ($CGBENCH_{n,r}$) which represents the average difference between historical city gate prices and model results for the historical years of the model. These equations are defined below:

$$\begin{aligned} CGPR_{n,r} = {} & NODE\_ENDPR_{n,r} + INTRAREG\_TAR_{n,r} + \\ & INTRAST\_TAR_{r} + CGBENCH_{n,r} \end{aligned} \tag{99}$$

such that:

$$CGBENCH_{n,r} = avg(HCG\_BENCH_{n,r,HISYR}) = avg(HCGPR_{n,r,HISYR} - CGPR_{n,r}) \tag{100}$$

where,

$CGPR_{n,r}$ = City gate price in region r on network n in each HISYR (87$/Mcf)
$NODE\_ENDPR_{n,r}$ = Node price for region r on network n (87$/Mcf)
$INTRAREG\_TAR_{n,r}$ = Intraregional tariff for region r on network n (87$/Mcf)
$INTRAST\_TAR_{r}$ = Intrastate tariff in region r (87$/Mcf)
$CGBENCH_{n,r}$ = City gate benchmark factor for region r on network n (87$/Mcf)
$HCG\_BENCH_{n,r,HISYR}$ = City gate benchmark factors for region r on network n in historical years HISYR (87$/Mcf)

$HCGPR_{n,r,HISYR}$ = Historical city gate price in region r on network n in historical year HISYR (87$/Mcf)
n = network (peak and off-peak)
r = region (lower 48 only)
HISYR = historical year, over which average is taken (2004-2008, excluding the outlier year of 2006)
avg = straight average of indicated value over indicated historical years of the model.

The intraregional tariffs are the sum of a usage fee (INTRAREG_FIXTAR), provided by the Pipeline Tariff Submodule, and a reservation fee that is set using the same function NGPIPE_VARTAR that is used in setting interregional tariffs and was described previously. The benchmark factor represents an adjustment to calibrate city gate prices to historical values.

Seasonal distributor tariffs are then added to the city gate prices to get seasonal, sectoral delivered prices by the NGTDM regions for nonelectric sectors and by the NGTDM/EMM subregions for the electric generation sector. The prices for residential, commercial, and electric generation sectors (core and noncore) are then adjusted using STEO benchmark factors ($SCALE\_FPR_{sec,t}$, $SCALE\_IPR_{sec,t}$)[70] to calibrate the results to equal the corresponding national STEO delivered prices. Each seasonal sector price is then averaged to get an annual, sectoral delivered price for each representative region. The following equations apply.

Nonelectric Sectors (except core transportation):

$$NGPR\_SF_{n,sec,r} = CGPR_{n,r} + DTAR\_SF_{n,sec,r} + SCALE\_FPR_{sec,t}$$

$$NGPR\_SI_{n,sec,r} = CGPR_{n,r} + DTAR\_SI_{n,sec,r} + SCALE\_IPR_{sec,t} \quad (101)$$

$$NGPR\_F_{sec,r} = NGPR\_SF_{PK,sec,r} * PKSHR\_DMD_{sec,r} + NGPR\_SF_{OP,sec,r} * (1.- PKSHR\_DMD_{sec,r})$$

$$NGPR\_I_{sec,r} = NGPR\_SI_{PK,sec,r} * PKSHR\_DMD_{sec,r} + NGPR\_SI_{OP,sec,r} * (1.- PKSHR\_DMD_{sec,r}) \quad (102)$$

where,

$NGPR\_SF_{n,sec,r}$ = Seasonal (n) core nonelectric sector (sec) price in region r (87$/Mcf)
$NGPR\_SI_{n,sec,r}$ = Seasonal (n) noncore nonelectric sector (sec) price in region r (87$/Mcf)
$NGPR\_F_{sec,r}$ = Annual core nonelectric sector (sec) price in region r (87$/Mcf)
$NGPR\_I_{sec,r}$ = Annual noncore nonelectric sector (sec) price in region r (87$/Mcf)

[70]The STEO scale factors are linearly phased out over a user-specified number of years (Appendix E, STPHAS_YR) after the last STEO year. STEO benchmarking is not done for the industrial price, because of differences in the definition of the price in the STEO versus the price in the AEO, nor for the transportation sector since the STEO does not include a comparable value.

$CGPR_{n,r}$ = City gate price in region r on network n (87$/Mcf)
$DTAR\_SF_{n.sec,r}$ = Seasonal (n) distributor tariff to core nonelectric sector (sec) in region r (87$/Mcf)
$DTAR\_SI_{n.\,sec,r}$ = Seasonal (n) distributor tariff to noncore nonelectric sector (sec) in region r (87$/Mcf)
$PKSHR\_DMD_{sec,r}$ = Average (2001-2009) fraction of annual consumption for nonelectric sector in peak season for region r
$SCALE\_FPR_{sec,t}$ = STEO benchmark factor for core delivered prices for sector sec, in year t (87$/Mcf)
$SCALE\_IPR_{sec,t}$ = STEO benchmark factor for noncore delivered prices for sector sec, in year t (87$/Mcf)
n = network (peak or off-peak)
sec = nonelectric sector
r = region (lower 48 only)

Electric Generation Sector:

$$NGUPR\_SF_{n,j} = CGPR_{n,r} + UDTAR\_SF_{n,j} + SCALE\_FPR_{sec,t}$$
$$NGUPR\_SI_{n,j} = CGPR_{n,r} + UDTAR\_SI_{n,j} + SCALE\_IPR_{sec,t} \tag{103}$$

$$NGUPR\_F_{j} = NGUPR\_SF_{PK,j} * PKSHR\_UDMD_{j} + NGUPR\_SF_{OP,j} * (1. - PKSHR\_UDMD_{j})$$
$$NGUPR\_I_{j} = NGUPR\_SI_{PK,j} * PKSHR\_UDMD_{j} + NGUPR\_SI_{OP,j} * (1. - PKSHR\_UDMD_{j}) \tag{104}$$

where,

$NGUPR\_SF_{n,j}$ = Seasonal (n) core utility sector price in region j (87$/Mcf)
$NGUPR\_SI_{n,j}$ = Seasonal (n) noncore utility sector price in region j (87$/Mcf)
$NGUPR\_F_{j}$ = Annual core utility sector price in region j (87$/Mcf)
$NGUPR\_I_{j}$ = Annual noncore utility sector price in region j (87$/Mcf)
$CGPR_{n,r}$ = City gate price in region r on network n (87$/Mcf)
$UDTAR\_SF_{n,j}$ = Seasonal (n) distributor tariff to core utility sector in region j (87$/Mcf)
$UDTAR\_SI_{n,j}$ = Seasonal (n) distributor tariff to noncore utility sector in region j (87$/Mcf)
$PKSHR\_UDMD_{j}$ = Average (1994-2009, except for New England 1997-2009) fraction of annual consumption for the electric generator sector in peak season, for region j
$SCALE\_FPR_{sec,t}$ = STEO benchmark factor for core delivered prices for sector sec, in year t (87$/Mcf)
$SCALE\_IPR_{sec,t}$ = STEO benchmark factor for noncore delivered prices for sector sec, in year t (87$/Mcf)

n = network (peak PK or off-peak OP)
sec = utility sector (electric generation only)
r = region (lower 48 only)
j = NGTDM/EMM subregion

For *AEO2011*, the natural gas price that was finally sent to the Electricity Market Module for both core and noncore customers was the quantity-weighted average of the core and noncore prices derived from the above equations. This was done to alleviate some difficulties within the Electricity Market Module as selections were being made between different types of natural gas generation equipment.

Core Transportation Sector:

A somewhat different methodology is used to determine natural gas delivered prices for the core (F) transportation sector. The core transportation sector consists of a personal vehicles component and a fleet vehicles component. Like the other nonelectric sectors, seasonal distributor tariffs are added to the regional city gate prices to determine seasonal delivered prices for both components. Annual core prices are then established for each component in a region by averaging the corresponding seasonal prices, as follows:

$$NGPR\_TRPV\_SF_{n,r} = CGPR_{n,r} + DTAR\_TRPV\_SF_{n,r} + SCALE\_FPR_{sec,t}$$
$$NGPR\_TRFV\_SF_{n,r} = CGPR_{n,r} + DTAR\_TRFV\_SF_{n,r} + SCALE\_FPR_{sec,t} \tag{105}$$

$$NGPR\_TRPV\_F_{r} = NGPR\_TRPV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + NGPR\_TRPV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r})$$
$$NGPR\_TRFV\_F_{r} = NGPR\_TRFV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + NGPR\_TRFV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r}) \tag{106}$$

where,

$NGPR\_TRPV\_SF_{n,r}$ = Seasonal (n) price of natural gas used by personal vehicles (core) in region r (87$/Mcf)
$NGPR\_TRFV\_SF_{n,r}$ = Seasonal (n) price of natural gas used by fleet vehicles (core) in region r (87$/Mcf)
$DTAR\_TRPV\_SF_{n,r}$ = Seasonal (n) distributor tariff to core transportation (personal vehicles) sector in region r (87$/Mcf)
$DTAR\_TRFV\_SF_{n,r}$ = Seasonal (n) distributor tariff to core transportation (fleet vehicles) sector in region r (87$/Mcf)
$CGPR_{n,r}$ = City gate price in region r on network n (87$/Mcf)
$NGPR\_TRPV\_F_{r}$ = Annual price of natural gas used by personal vehicles (core) in region r (87$/Mcf)
$NGPR\_TRFV\_F_{r}$ = Annual price of natural gas used by fleet vehicles (core) in region r (87$/Mcf)

$PKSHR\_DMD_{sec,r}$	=	Fraction of annual consumption for the transportation sector (sec=4) in the peak season for region r (set to PKSHR_YR)
$SCALE\_FPR_{sec,t}$	=	STEO benchmark factor for core delivered prices for sector sec, in year t (set to 0 for transportation sector), (87$/Mcf)
n	=	network (peak PK or off-peak OP)
sec	=	transportation sector =4
r	=	region (lower 48 only)

Once the personal vehicles price for natural gas is established, the two core component prices are averaged (using quantity weights) to produce an annual core price for each region ($NGPR\_F_{sec=4,r}$). Seasonal core prices are also determined by quantity-weighted averaging of the two seasonal components ($NGPR\_SF_{n,sec=4,r}$).

Regional delivered prices can be used within the ITS cycle to approximate a demand response. The submodule can then be resolved with adjusted consumption levels in an effort to speed NEMS convergence. Finally, once the ITS has converged, regional prices are averaged using quantity weights to compute Census Division prices, which are sent to the corresponding NEMS modules.

Import Prices

The price associated with Canadian imports at each of the module's border crossing points is established during the ITS convergence process. Each of these border-crossing points is represented by a node in the network. The import price for a given season and border crossing is therefore equal to the price at the associated node. For reporting purposes, these node prices are averaged using quantity weights to derive an average annual Canadian import price. The prices for imports at the three Mexican border crossings are set to the average wellhead price in the nearest NGTDM region plus a markup (or markdown) that is based on the difference between similar import and wellhead prices historically. The structure for setting LNG import prices is similar to setting Mexican import prices, although regional city gate prices are used instead of wellhead prices. For the facilities for which historical prices are not available (i.e., generic new facilities), an assumption was made about the difference between the regional city gate price and the LNG import price (LNGDIFF, Appendix E).

5. Distributor Tariff Submodule Solution Methodology

This chapter discusses the solution methodology for the Distributor Tariff Submodule (DTS) of the Natural Gas Transmission and Distribution Module (NGTDM). Within each region, the DTS develops seasonal, market-specific distributor tariffs (or city gate to end-use markups) that are applied to projected seasonal city gate prices to derive end-use or delivered prices. Since most industrial and electric generator customers do not purchase their gas through local distribution companies, their "distributor tariff" represents the difference between the average price paid by local distribution companies at the city gate and the average price paid by the industrial or electric generator customer.[71] Distributor tariffs are defined for both core and noncore markets within the industrial and electric generator sectors, while residential, commercial, and transportation sectors have distributor tariffs defined only for the core market, since noncore customer consumption in these sectors is assumed to be insignificant and set to zero. The core transportation sector is composed of two categories of compressed natural gas (CNG) consumers (fleet vehicles and personal vehicles); therefore, separate distributor tariffs are developed for each of these two categories.

For the residential, commercial, industrial, and electric generation sectors distributor tariffs are based on econometrically estimated equations and are driven in part by sectoral consumption levels.[72] This general approach was taken since data are not reasonably obtainable to develop a detailed cost-based accounting methodology similar to the approach used for interstate pipeline tariffs in the Pipeline Tariff Submodule. Distribution charges for CNG in vehicles are set to the sum of historical tariffs for delivering natural gas to refueling stations, federal and state motor fuels taxes and credits, and estimates of dispensing charges. The specific methodologies used to calculate each sector's distributor tariffs are discussed in the remainder of this chapter.

Residential and Commercial Sectors

Residential and commercial distributor tariffs are projected using econometrically estimated equations. The primary explanatory variables are floorspace and commercial natural gas consumption per floorspace for the commercial tariff, and number of households and natural gas consumption per household for the residential sector tariff. In both cases distributor tariffs are estimated separately for the peak and off-peak periods, as follows:

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[71] It is not unusual for these "markups" to be negative.

[72] Historical distributor tariffs for a sector in a particular region/season can be estimated by taking the difference between the average sectoral delivered price and the average city gate price in the region/season (Appendix E, HCGPR).

Residential peak

$$\text{DTAR\_SF}_{s=1,r,n=1} = e^{\text{PRSREGPK19}_{r,n=1}} * \text{NUMRS}_{r,t}^{0.162972} * \left(\frac{\text{BASQTY\_SF}_{s=1,r,n=1} + \text{BASQTY\_SI}_{s=1,r,n=1}}{\text{NUMRS}_{r,t}}\right)^{-0.607267} * \text{DTAR\_SFPREV}_{s=1,r,n=1}^{0.231296} * e^{(-0.231296*\text{PRSREGPK19}_{r,n=1})} * \text{NUMRS}_{r,t-1}^{-0.231296*0.162972} * \left(\frac{\text{BASQTY\_SFPREV}_{s=1,r,n=1} + \text{BASQTY\_SIPREV}_{s=1,r,n=1}}{\text{NUMRS}_{r,t-1}}\right)^{(-0.231296*-0.607267)} \quad (107)$$

Residential off-peak

$$\text{DTAR\_SF}_{s=1,r,n=2} = e^{\text{PRSREGPK19}_{r,n=2}} * \text{NUMRS}_{r,t}^{0.282301} * \left(\frac{\text{BASQTY\_SF}_{s=1,r,n=2} + \text{BASQTY\_SI}_{s=1,r,n=2}}{\text{NUMRS}_{r,t}}\right)^{-0.814968} * \text{DTAR\_SFPREV}_{s=1,r,n=2}^{0.231296} * e^{(-0.202612*\text{PRSREGPK19}_{r,n=2})} * \text{NUMRS}_{r,t-1}^{-0.202612*0.282301} * \left(\frac{\text{BASQTY\_SFPREV}_{s=1,r,n=2} + \text{BASQTY\_SIPREV}_{s=1,r,n=2}}{\text{NUMRS}_{r,t-1}}\right)^{(-0.202612*-0.814968)} \quad (108)$$

Commercial peak

$$\text{DTAR\_SF}_{s=2,r,n=2} = e^{\text{PCMREGPK13}_{r,n=1}} * \text{FLRSPC12}_{r,t}^{0.218189} * \left(\frac{\text{BASQTY\_SF}_{s=2,r,n=1} + \text{BASQTY\_SI}_{s=2,r,n=1}}{\text{FLRSPC12}_{r,t}}\right)^{-0.217322} * \text{DTAR\_SFPREV}_{s=2,r,n=1}^{0.284608} * e^{(-0.284608*\text{PCMREGPK13}_{r,n=1})} * \text{FLRSPC12}_{r,t-1}^{-0.284608*0.218189} \left(\frac{\text{BASQTY\_SFPREV}_{s=2,r,n=1} + \text{BASQTY\_SIPREV}_{s=2,r,n=1}}{\text{FLRSPC12}_{r,t-1}}\right)^{(-0.284608*-0.217322)} \quad (109)$$

Commercial off-peak

$$\mathrm{DTAR\_SF}_{s=2,r,n=2} = e^{\mathrm{PCMREGPK13}_{r,n=2}} * \mathrm{FLRSPC12}_{r,t}^{0.530831} * \left(\frac{\mathrm{BASQTY\_SF}_{s=2,r,n=2} + \mathrm{BASQTY\_SI}_{s=2,r,n=2}}{\mathrm{FLRSPC12}_{r,t}}\right)^{-0.613588} * \mathrm{DTAR\_SFPREV}_{s=2,r,n=2}^{0.166956} * e^{(-0.166956*\mathrm{PCMREGPK13}_{r,n=2})} * \mathrm{FLRSPC12}_{r,t-1}^{-0.166956*0.53083} \left(\frac{\mathrm{BASQTY\_SFPREV}_{s=2,r,n=2} + \mathrm{BASQTY\_SIPREV}_{s=2,r,n=2}}{\mathrm{FLRSPC12}_{r,t-1}}\right)^{(-0.166956*-0.613588)} \quad (110)$$

where,

$$\mathrm{NUMRS}_{r,t} = \mathrm{oRSGASCUST}_{cd,t} * \mathrm{RECS\_ALIGN}_{r} * \mathrm{NUM\_REGSHR}_{r} \quad (111)$$

and,

$$\mathrm{FLRSPC12}_{r,t} = (\mathrm{MC\_COMMFLSP}_{1,cd,t} - \mathrm{MC\_COMMFLSP}_{8,cd,t}) * \mathrm{SHARE}_{r} \quad (112)$$

where,

$\mathrm{DTAR\_SF}_{s,r,n}$	=	core distributor tariff in current forecast year for sector s, region r, and network n (1987$/Mcf)
$\mathrm{DTAR\_SFPREV}_{s,r,n}$	=	core distributor tariff in previous forecast year (1987$/Mcf). [For first forecast year set at the 2008 historical value.]
$\mathrm{BASQTY\_SF}_{s,r,n}$	=	sector (s) level firm gas consumption for region r, and network n (Bcf)
$\mathrm{BASQTY\_SI}_{s,r,n}$	=	sector (s) level nonfirm gas consumption for region r, and network n (Bcf) (assumed at 0 for residential and commercial)
$\mathrm{BASQTY\_SFPREV}_{s,r,n}$	=	sector (s) level gas consumption for region r, and network n in previous year (Bcf) (assumed at 0 for residential and commercial)
$\mathrm{BASQTY\_SIPREV}_{s,r,n}$	=	sector (s) level nonfirm gas consumption for region r, and network n in previous year (Bcf)
NUMRS	=	number of residential customers in year t
$\mathrm{PRSREGPK19}_{r,n}$	=	residential, regional, period specific, constant term (Table F6, Appendix F)
$\mathrm{PCMREGPK13}_{r,n}$	=	commercial, regional, peak specific, constant term (Table F7, Appendix F)
$\mathrm{oRSGASCUST}_{cd,t-1}$	=	number of residential gas customers by census division in the previous forecast year (from NEMS residential demand module)
$\mathrm{RECS\_ALIGN}_{r}$	=	factor to align residential customer count data from EIA's 2005 Residential Consumption Survey (RECS), the data on which oRSGASCUST is based, with similar data from the EIA's Natural Gas Annual, the data on which the DTAR_SF estimation is based.
$\mathrm{NUM\_REGSHR}_{r}$	=	share of residential customers in NGTDM region r relative to the number in the larger or equal sized associated census division, set to values in last historical year, 2008. (fraction, Appendix E)

$FLRSPC12_r$ = commercial floorspace by NGTDM region (total net of for manufacturing) (billion square feet)
$MC\_COMMFLSP_{1,cd,t}$ = commercial floorspace by Census Division (total, including manufacturing)
$MC\_COMMFLSP_{8,cd,t}$ = commercial floorspace by Census Division (manufacturing)
$SHARE_r$ = assumed fraction of the associated census division's commercial floorspace within each of the 12 NGTDM regions based on population data (1.0, 1.0, 1.0, 1.0, 0.66, 1.0, 1.0, 0.59, 0.24, 0.34, 0.41, 0.75)
s = sector (=1 for residential, =2 for commercial)
cd = census division
r = region (12 NGTDM regions)
n = network (=1 for peak, =2 for off-peak)
t = forecast year (e.g., 2010)

Parameter values and details about the estimation of these equations can be found in Tables F6 and F7 of Appendix F.

Industrial Sector

For the industrial sector, a single distributor tariff (i.e., no distinction between core and noncore) is estimated for each season and region as a function of the industrial consumption level in that season and region. Next, core seasonal tariffs are set by assuming a differential between the core price and the estimated distributor tariff for the season and region, based on historical estimates. The noncore price is set to insure that the quantity-weighted average of the core and noncore price in a season and region will equal the originally estimated tariff for that season and region. Historical prices for the industrial sector are estimated based on the data that are available from the Manufacturing Energy Consumption Survey (MECS) (Table F5, Appendix F). The industrial prices within EIA's Natural Gas Annual only represent industrial customers who purchase gas through their local distribution company, a small percentage of the total; whereas the prices in the MECS represent a much larger percentage of the total industrial sector. The equation for the single seasonal/regional industrial distributor tariff follows:

$$\begin{aligned} TAR = {} & 0.199135 + PINREG15_r + PIN\_REGPK15_{r,n} + \\ & (-0.000317443 * QCUR_n) + (0.423561 * TARLAG_n) \\ & - 0.423561 * [0.199135 + PIN\_REG15_r + PIN\_REGPK15_{r,n} + \\ & (-0.000317443 * QLAG_n)] \end{aligned} \tag{113}$$

The core and noncore distributor tariffs are set using:

$$DTAR\_SF_{s=3,r,n} = TAR + FDIFF_{cr} \tag{114}$$

$$\mathrm{DTAR\_SI}_{s=3,r,,n} = \frac{(\mathrm{TAR} * \mathrm{QCUR}_n) - (\mathrm{DTAR\_SF}_{s=3,r,n} * \mathrm{BASQTY\_SF}_{s=3,r,n})}{\mathrm{BASQTY\_SI}_{s=3,r,n}} \tag{115}$$

where,

TAR	=	seasonal distributor tariff for industrial sector in region r (87$/Mcf)
TARLAG_n	=	seasonal distributor tariff for the industrial sector (s=3) in region r in the previous forecast year (87$/Mcf)
FDIFF_{cr}	=	historical average difference between core and average industrial price (1987$/Mcf, Appendix E)
$\mathrm{PIN\_REG15}_r$	=	estimated constant term (Table F4, Appendix F)
$\mathrm{PIN\_REGPK15}_{r,n}$	=	estimated coefficient, set to zero for the off-peak period and for any region where the coefficient is not statistically significant
$\mathrm{DTAR\_SF}_{n,s,r}$	=	seasonal distributor tariff for the core industrial sector (s=3) in region r (87$/Mcf)
$\mathrm{DTAR\_SI}_{n,s,r}$	=	seasonal distributor tariff for the noncore industrial sector (s=3) in region r (87$/Mcf)
$\mathrm{DTAR\_SFPREV}_{n,s,r}$	=	seasonal distributor tariff for the core industrial sector (s=3) in region r (87$/Mcf) in the previous forecast year [In the first forecast year set to the estimated average historical value from 2006 to 2009 [Table F5, Appendix F] (87$/Mcf)]
$\mathrm{BASQTY\_SF}_{n,s=3,r}$	=	seasonal core natural gas consumption for industrial sector(s=3) in the current forecast year (Bcf)
$\mathrm{BASQTY\_SI}_{n,s=3,r}$	=	seasonal noncore natural gas consumption for industrial sector (s=3) in the current forecast year (Bcf)
QCUR_n	=	sum of BASQTY_SF and BASQTY_SI for industrial in a particular season and region
QLAG_n	=	sum of BASQTY_SFPREV and BASQTY_SIPREV for industrial in a particular season and region, the value of QCUR in the last forecast year
s	=	end-use sector index (s=3 for industrial sector)
n	=	network (peak or off-peak)
r	=	NGTDM region
cr	=	the census region associated with the NGTDM region

Parameter values and details about the estimation of these two equations can be found in Table F4 and F5, Appendix F.

Electric Generation Sector

Distributor tariffs for the electric generation sector do not represent a charge imposed by a local distribution company; rather they represent the difference between the average city gate price in each NGTDM region and the natural gas price paid on average by electric generators in each NGTDM/EMM region, and are often negative. A single markup or tariff (i.e., no distinction between core and noncore) is projected for each season and region using econometrically estimated equations, as was done for the industrial sector. However, the current version of the model (as used for *AEO2011*) assigns this same value to both the core and noncore segments.[73] The estimated equations for the distributor tariffs for electric generators are a function of natural gas consumption by the sector relative to consumption by the other sectors. The greater the electric consumption share, the greater the price difference between the electric sector and the average, as they will need to reserve more space on the pipeline system. The specific equations follow:

$$\begin{aligned} UDTAR\_SF_{n,j} = {} & (-0.153777 + 0.0299295) + PELREG31_{n,j} + \\ & (0.000000704 * qelec_{n,j}) + (0.281378 * UDTAR\_SFPREV_{n,j}) \\ & - 0.281378 * [(-0.153777 + 0.0299295) + PELREG31_{n,j} + \\ & (0.000000704 * qeleclag_{n,j})] \end{aligned} \tag{116}$$

where,

$$qelec_{n,j} = (BASUQTY\_SF_{n,j} + BASUQTY\_SI_{n,j}) * 1000 \tag{117}$$

$$qeleclag_{n,j} = (BASUQTY\_SFPREV_{n,j} + BASUQTY\_SIPREV_{n,j}) * 1000 \tag{118}$$

$UDTAR\_SI_{n,j}$ = $UDTAR\_SF_{n,j}$ for all n and j,

where,

$UDTAR\_SF_{n,j}$ = seasonal core electric generation sector distributor tariff, current forecast year ($/Mcf)

$UDTAR\_SI_{n,j}$ = seasonal noncore electric generation sector distributor tariff, current forecast year ($/Mcf)

$UDTAR\_SFPREV_{n,j}$ = seasonal core electric generation sector distributor tariff, previous forecast year ($/Mcf)

$BASUQTY\_SF_{n,j}$ = core electric generator gas consumption, current forecast year (Bcf)

$BASUQTY\_SI_{n,j}$ = noncore electric generator gas consumption, current forecast year (Bcf)

$BASUQTY\_SFPREV_{n,j}$ = core electric generator gas consumption in previous forecast year (Bcf)

$BASUQTY\_SIPREV_{n,j}$ = noncore electric generator gas consumption in previous forecast year (Bcf)

$PELREG31_{n=1,j}$ = $PELREG31_j$ in code, regional constant terms for peak period (Table F8, Appendix F)

$PELREG31_{n=2,j}$ = $PELREG32_j$ in code, regional constant terms for off-peak period (Table F8, Appendix F)

n = network (peak=1 or off-peak=2)

j = NGTDM/EMM region (see chapter 2)

[73]This distinction was eliminated several years ago because of operational concerns in the Electricity Market Module. In addition, there are some remaining issues concerning the historical data necessary to generate separate price series for the two segments.

Parameter values and details about the estimation of these two equations can be found in Table F8, Appendix F.

Transportation Sector

Consumers of compressed natural gas (CNG) have been classified into two end-use categories within the core transportation sector: fleet vehicles and personal vehicles (i.e., CNG sold at retail). A distributor tariff is set for both categories to capture 1) the cost of the natural gas delivered to the dispensing station above the city gate price, 2) the per-unit cost or charge for dispensing the gas, and 3) federal and state motor fuels taxes and credits.

For both categories, the distribution charge for the CNG delivered to the station is based on the historical difference between the price reported for the transportation sector in EIA's *Natural Gas Annual* (which should reflect this delivered price) and the city gate price. Similarly federal and state motor fuels taxes are assumed to be the same for both categories and held constant in nominal dollars.[74] The Highway Bill of 2005 raised the motor fuels tax for CNG.[75] The model adjusts the distribution costs accordingly. A potential difference in the pricing for the two categories is the assumed per-unit dispensing charge. Currently the refueling options available for personal natural gas vehicles are largely limited to the same refueling facilities used by fleet vehicles. Therefore, the assumption in the model is that the dispensing charge will be similar for fleet and personal vehicles ($RETAIL\_COST_2$) unless there is a step increase in the number of retail stations selling natural gas in response to an expected increase in the number of personal vehicles. In such a case, an additional markup is added to the natural gas price to personal vehicles to account for the profit of the builder (RET_MARK), as described below. The distributor tariffs for CNG vehicles are set as follows:

$$\begin{aligned} DTAR\_TRFV\_SF_{n,r} = \{ & HDTAR\_SF_{n,s=4,r,EHISYR} \\ & * (1 - TRN\_DECL)^{YR-DECL}\} + RETAIL\_COST_2 \\ & + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \end{aligned} \tag{119}$$

$$\begin{aligned} DTAR\_TRPV\_SF_{n,r} = \{ & HDTAR\_SF_{n,s=4,r,EHISYR} \\ & * (1 - TRN\_DECL)^{YR-DECL}\} + RETAIL\_COST_2 \\ & + CNG\_RETAIL\_MARKUP_r + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \end{aligned} \tag{120}$$

where,

[74] Motor vehicle fuel taxes are assumed constant in current year dollars throughout the forecast to reflect current laws. Within the model these taxes are specified in 1987 dollars.

[75] The Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU), Section 1113. The bill also allowed for an excise tax credit of $0.50 per gasoline gallon equivalent to be paid to the seller of the CNG through September of 2009. The model assumes that the subsidy will be passed through to consumers.

$DTAR\_TRFV\_SF_{n,r}$ = distributor tariff for the fleet vehicle transportation sector (87$/Mcf)
$DTAR\_TRPV\_SF_{n,r}$ = distributor tariff for the personal vehicle transportation sector (87$/Mcf)
$HDTAR\_SF_{n,s,r,EHISYR}$ = historical (2009) distributor tariff for the transportation sector to deliver the CNG to the station[76] (87$/ Mcf)
TRN_DECL = fleet vehicle distributor decline rate, set to zero for *AEO2011* (fraction, Appendix E)
YR_DECL = difference between the current year and the last historical year over which the decline rate is applied
$RETAIL\_COST_2$ = assumed additional charge related to providing the dispensing service to customers, at a fleet refueling station (87$/Mcf, Appendix E)
$CNG\_RETAIL\_MARKUP_r$ = markup for natural gas sold at retail stations (described below)
$STAX_r$ = State motor vehicle fuel tax for CNG (current year $/Mcf, Appendix E)
FTAX = Federal motor vehicle fuel tax minus federal excise motor fuel credit for CNG (current year $/Mcf, Appendix E)
MC_PCWGDP_t = GDP conversion from current year dollars to 87 dollars [from the NEMS macroeconomic module]
n = network (peak or off-peak)
s = end-use sector index (s=4 for transportation sector)
r = NGTDM region
EHISYR = index defining last year that historical data are available
t = forecast year

A new algorithm was developed for *AEO2010* which projects whether construction of CNG fueling stations is economically viable in any of the NGTDM regions and, if so, sets the added charge that will result. In addition, the model provides the NEMS Transportation Sector Module with a projection of the fraction of retail refueling stations that sell natural gas. This is a key driver in the transportation module for projecting the number of compressed natural gas vehicles purchased and the resulting consumption level. While demand for CNG for personal vehicles is increased when fueling infrastructure is built, at the same time the viability of fueling infrastructure depends on sufficient demand to support it. A reduced form of the NEMS Transportation Sector Module was created for use in the NGTDM to estimate the increase in demand for CNG due to infrastructure construction, in order to project the revenue from a infrastructure building project, and then to assess its viability.

The basic algorithm involves 1) assuming a set increase in the number of stations selling CNG, 2) assuming CNG will be priced at a discount to the price of motor gasoline once it starts penetrating, 3) estimating the expected demand for CNG given the increased supply availability and price, 4) calculating the expected revenue per station that will cover capital expenditures

[76]EIA published, annual, State level data are used to set regional historical end-use prices for CNG vehicles. Since monthly data are not available for this sector, seasonal differentials for the industrial sector are applied to annual CNG data to approximate seasonal CNG prices.

(i.e., discounting for taxes, gas purchase costs, and other operating costs), 5) checking the revenue against infrastructure costs to determine viability, and 6) if viable, assuming the infrastructure will be added and the retail price changed accordingly.

The algorithm starts by testing the effects of building a large number of CNG stations (i.e., primarily by offering CNG at existing gasoline stations). The increase in availability that is tested is assumed to be a proportion of the number of gasoline stations in the region, as follows:

$$TOTPUMPS = NSTAT_r * (MAX\_CNG\_BUILD + CNGAVAIL_{t-1}) \tag{121}$$

where,

TOTPUMPS	=	the number of retail stations selling CNG in the region
$NSTAT_r$	=	the number of gasoline stations in the region at the beginning of the projection period (Appendix E)
$CNGAVAIL_{t-1}$	=	fraction of total retail refueling stations selling CNG last year
MAX_CNG_BUILD	=	assumed fraction of stations that can add CNG refueling this year (Appendix E).
r	=	census division
t	=	year

The assumed regional retail markup to cover capital costs if CNG infrastructure is built is set as follows:

$$TEST\_MARKUP_r = \text{minimum}\{5.0, MAX\_CNGMARKUP\} \tag{122}$$

where,

$$MAX\_CNGMARKUP_r = 0.75 * \{PMGTR_{r,t-1} - (PGFTRPV_{r,t-1} - CNG\_RETAIL\_MARKUP_r)\} \tag{123}$$

where,

$TEST\_MARKUP_r$	=	assumed regional retail markup (87$/MMBtu)
$MAX\_CNG\_MARKUP_r$	=	assumed maximum markup that can be added to base line cost of dispensing CNG to cover capital expenditures (87$/MMBtu) [Note: base line costs include taxes and fuel and basic operating costs]
$PMGTR_r$	=	retail price of motor gasoline (87$/MMBtu)
PMGFTRPV	=	retail price of CNG (87$/MMBtu)
$CNG\_RETAIL\_MARKUP_r$	=	retail CNG markup above base line costs added last year (87$/MMBtu)
0.75	=	assumed economic rent that can be captured relative to the difference between the retail price of motor gasoline and the retail price of CNG (fraction)
5.0	=	assumed minimum retail CNG markup (87$/MMBtu)

For each model year and region, the present value of projected revenue is determined with the following equation:

$$REVENUE = \sum_{n=1}^{CNG\_HRZ} \frac{TEST\_MARKUP_r * DEMAND * 1000000}{TOTPUMPS * (1 + CNG\_WACC)^n} \quad (124)$$

where,

REVENUE	=	the net revenue per station (above the basic operating expenses) after infrastructure is added in the region (1987 dollars)
CNG_HRZ	=	the time horizon for the revenue calculation, corresponding to the number of years over which the capital investment is assumed to need to be recovered (Appendix E)
$TEST\_MARKUP_r$	=	assumed regional retail markup above baseline costs (87$/MMBtu)
DEMAND	=	estimated consumption of CNG by personal vehicles if the infrastructure is added and the implied retail price is charged (trillion BTU), described at the end of this section
TOTPUMPS	=	the number of retail stations selling CNG in the region
CNG_WACC	=	assumed weighted average cost of capital for financing the added CNG infrastructure (Appendix E)

The model compares the present value of the projected revenue per station from an infrastructure build to the assumed cost of a station (CNG_BUILDCOST, Appendix E) to make the decision of whether stations are built or not. The cost of a station reflects the estimated cost of building a single pumping location in an existing retrial refueling station, considering the tax value of depreciation and a payback number of years (CNG_HRZ, Appendix E) and an assumed weighted average cost of capital (CNG_WACC, Appendix E). If the revenue is sufficient in a region then the availability of CNG stations in that region are increased and the retail markup is set to the markup that was tested. The equations for new retail markup and availability when stations have been built are given in the following:

$$CNGAVAIL_{r,t} = CNGAVAIL_{r,t-1} + MAX\_CNG\_BUILD \quad (125)$$

$$RET\_MARK_r = TEST\_MARKUP \quad (126)$$

where,

$CNGAVAIL_{r,t}$	=	fraction of regional retail refueling stations selling CNG
MAX_CNG_BUILD	=	incremental fraction of retail refueling stations selling CNG with added infrastructure in the year
RET_MARK_r	=	CNG retail markup above baseline costs (87$/MMBtu)
TEST_MARKUP	=	assumed CNG retail markup above baseline costs, based on the difference between baseline CNG costs and motor gasoline prices (87$/MMBtu)
r	=	Census Division
t	=	year

These variables stay at last year's values if no stations have been built. The retail markup by NGTDM region (CNG_RETAIL_MARKUP), as used in the transportation sector distributor tariff equation, is set by assigning the retail markup (RET_MARK) from the associated Census Division.

The demand response for CNG use in personal vehicles was estimated by doing multiple runs of the Transportation Sector Module. The key variable that was varied was the availability of CNG refueling stations. Test runs were made over a range of availability values for nine different cases. The cases were defined with three different motor gasoline to CNG price differentials (a maximum, a minimum, and the average between the two) in combination with three different CNG vehicle purchase subsidies ($0, $20,000, $40,000 in 2009 dollars per vehicle).[77] For each of the resulting nine sets of runs the CNG demand response in the Pacific Census Division was estimated as a function of station availability in a log-linear form with a constant term. The demand response in the Pacific Division was estimated by linearly interpolating between the points in the resulting three dimensional grid for a given availability (fraction of stations offering CNG), price differential between CNG and motor gasoline, and allowed subsidy for purchasing a CNG vehicle. The estimated consumption levels in the other Census Divisions were set by scaling the Pacific Division consumption based on size (as measured by total transportation energy demand) relative to the Pacific Division.

[77]Based on current laws and regulations in the *AEO2011* Reference Case, the subsidy is set to $0. A nonzero subsidy option was included for potential scenario analyses.

6. Pipeline Tariff Submodule Solution Methodology

The Pipeline Tariff Submodule (PTS) sets rates charged for storage services and interstate pipeline transportation. The rates developed are based on actual costs for transportation and storage services. These cost-based rates are used as a basis for developing tariff curves for the Interstate Transmission Submodule (ITS). The PTS tariff calculation is divided into two phases: an historical year initialization phase and a forecast year update phase. Each of these two phases includes the following steps: (1) determine the various components, in nominal dollars, of the total cost-of-service, (2) classify these components as fixed and variable costs based on the rate design (for transportation), (3) allocate these fixed and variable costs to rate components (reservation and usage costs) based on the rate design (for transportation), and (4) for transportation: compute rates for services during peak and off-peak time periods; for storage: compute annual regional tariffs. For the historical year phase, the cost of service is developed from historical financial data on 28 major U.S. interstate pipeline companies; while for the forecast year update phase the costs are estimated using a set of econometric equations and an accounting algorithm. The pipeline tariff calculations are described first, followed by the storage tariff calculations, and finally a description of the calculation of the tariffs for moving gas by pipeline from Alaska and from the MacKenzie Delta to Alberta. A general overview of the methodology for deriving rates is presented in the following box. The PTS system diagram is presented in **Figure 6-1**.

The purpose of the historical year initialization phase is to provide an initial set of transportation revenue requirements and tariffs. The last historical year for the PTS is currently 2006, which need not align with the last historical year for the rest of the NGTDM. Ultimately the ITS requires pipeline and storage tariffs; whether they are based on historical or projected financial data is mechanically irrelevant. The historical year information is developed from existing pipeline company transportation data. The historical year initialization process draws heavily on three databases: (1) a pipeline financial database (1990-2006) of 28 major interstate natural gas pipelines developed by Foster Associates,[83] (2) "a competitive profile of natural gas services" database developed by Foster Associates,[84] and (3) a pipeline capacity database developed by the former Office of Oil and Gas, EIA.[85] The first database represents the existing physical U.S. interstate pipeline and storage system, which includes production processing, gathering, transmission, storage, and other. The physical system is at a more disaggregate level than the NGTDM network. This database provides detailed company-level financial, cost, and rate base parameters. It contains information on capital structure, rate base, and revenue requirements by major line item of the cost of service for the historical years of the model. The second Foster database contains

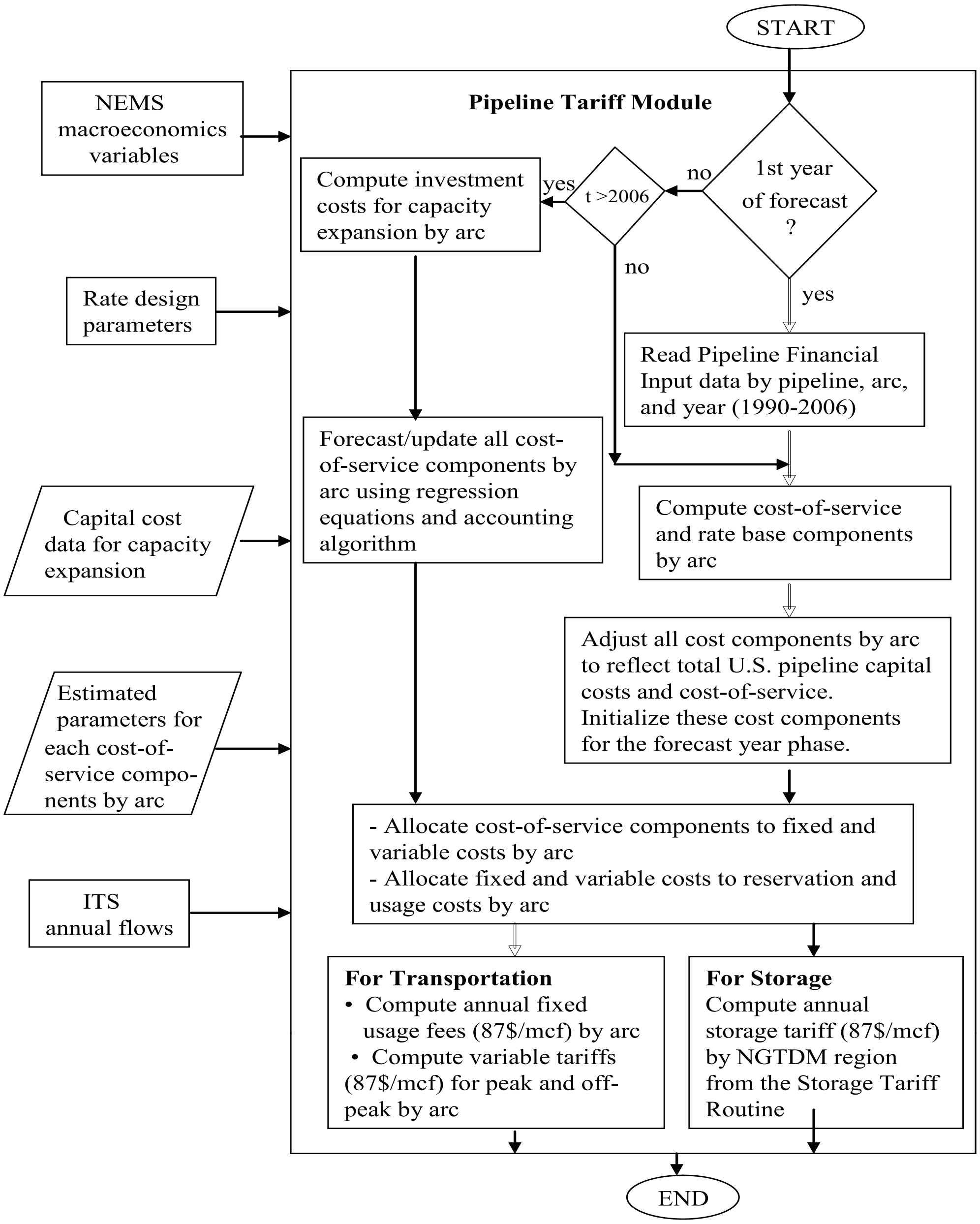
[83]Foster Financial Reports, 28 Major Interstate Natural Gas Pipelines, 2000, 2004 and 2007 Editions, Foster Associates, Inc., Bethesda, Maryland. The primary sources of data for these reports are FERC Form 2 and the monthly FERC Form 11 pipeline company filings. These reports can be purchased from Foster Associates.

[84]Competitive Profile of Natural Gas Services, Individual Pipelines, December 1997, Foster Associates, Inc., Bethesda, Maryland. Volumes III and IV of this report contain detailed information on the major interstate pipelines, including a pipeline system map, capacity, rates, gas plant accounts, rate base, capitalization, cost of service, etc. This report can be purchased from Foster Associates.

[85]A spreadsheet compiled by James Tobin of the Office of Oil and Gas containing historical and proposed state-to-state pipeline construction project costs, mileage, capacity levels and additions by year from 1996 to 2011, by pipeline company (data as of August 16, 2007).

detailed data on gross and net plant in service and depreciation, depletion, and amortization for individual plants (production processing and gathering plants, gas storage plants, gas transmission plants, and other plants) and is used to compute sharing factors by pipeline company and year to single out financial cost data for transmission plants from the "total plants" data in the first database.

Figure 6-1. Pipeline Tariff Submodule System Diagram



The third database contains information on pipeline financial construction projects by pipeline company, state-to-state transfer, and year (1996-2011). This database is used to determine factors to allocate the pipeline company financial data to the NGTDM interstate pipeline arcs based on capacity level in each historical year. These three databases are pre-processed offline to generate the pipeline transmission financial data by pipeline company, NGTDM interstate arc, and historical year (1990-2006) used as input into the PTS.

PTS Process for Deriving Rates

For Each Pipeline Arc

- Read historical financial database for 28 major interstate natural gas pipelines by pipeline company, arc, and historical year (1990-2006).

- Derive the total pipeline cost of service (TCOS)
  - Historical years
  - Aggregate pipeline TCOS items to network arcs
    - Adjust TCOS components to reflect all U.S. pipelines based on annual "Pipeline Economics" special reports in the Oil & Gas Journal
  - Forecast years
    - Include capital costs for capacity expansion
    - Estimate TCOS components from forecasting equations and accounting algorithm

- Allocate total cost of service to fixed and variable costs based on rate design

- Allocate costs to rate components (reservation and usage costs) based on rate design

- Compute rates for services for peak and off-peak time periods

For Each Storage Region:

- Derive the total storage cost of service (STCOS)

  - Historical years: read regional financial data for 33 storage facilities by node (NGTDM region) and historical year (1990-1998)
  - Forecast years:
    - Estimate STCOS components from forecasting equations and accounting algorithm
    - Adjust STCOS to reflect total U.S. storage facilities based on annual storage capacity data reported by EIA

- Compute annual regional storage rates for services

Historical Year Initialization Phase

The following section discusses two separate processes that occur during the historical year initialization phase: (1) the computation and initialization of the cost-of-service components, and (2) the computation of rates for services. The computation of historical year cost-of-service components and rates for services involves four distinct procedures as outlined in the above box and discussed below. Rates are calculated in nominal dollars and then converted to real dollars for use in the ITS.

Computation and Initialization of Pipeline Cost-of-Service Components

In the historical year initialization phase of the PTS, rates are computed using the following process: (Step 1) derivation and initialization of the total cost-of-service components, (Step 2) classification of cost-of-service components as fixed and variable costs, (Step 3) allocation of fixed and variable costs to rate components (reservation and usage costs) based on rate design, and (Step 4) computation of rates at the arc level for transportation services.

Step 1: Derivation and Initialization of the Total Cost-of-Service Components

The total cost-of-service for existing capacity on an arc consists of a just and reasonable return on the rate base plus total normal operating expenses. Derivations of return on rate base and total normal operating expenses are presented in the following subsections. The total cost of service is computed as follows:

$$TCOS_{a,t} = TRRB_{a,t} + TNOE_{a,t} \tag{127}$$

where,

$TCOS_{a,t}$ = total cost-of-service (dollars)
$TRRB_{a,t}$ = total return on rate base (dollars)
$TNOE_{a,t}$ = total normal operating expenses (dollars)
a = arc
t = historical year

Just and Reasonable Return. In order to compute the return portion of the cost-of-service at the arc level, the determination of capital structure and adjusted rate base is necessary. Capital structure is important because it determines the cost of capital to the pipeline companies associated with a network arc. The weighted average cost of capital is applied to the rate base to determine the return component of the cost-of-service, as follows:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \tag{128}$$

where,

$TRRB_{a,t}$ = total return on rate base after taxes (dollars)
$WAROR_{a,t}$ = weighted-average after-tax return on capital (fraction)
$APRB_{a,t}$ = adjusted pipeline rate base (dollars)
a = arc
t = historical year

In addition, the return on rate base $TRRB_{a,t}$ is broken out into the three components as shown below.

$$PFEN_{a,t} = \sum_{p} [(PFES_{a,p,t} / TOTCAP_{a,p,t}) * PFER_{a,p,t} * APRB_{a,p,t}] \tag{129}$$

$$CMEN_{a,t} = \sum_{p} [(CMES_{a,p,t} / TOTCAP_{a,p,t}) * CMER_{a,p,t} * APRB_{a,p,t}] \tag{130}$$

$$LTDN_{a,t} = \sum_{p} [(LTDS_{a,p,t} / TOTCAP_{a,p,t}) * LTDR_{a,p,t} * APRB_{a,p,t}] \tag{131}$$

such that,

$$TRRB_{a,t} = (PFEN_{a,t} + CMEN_{a,t} + LTDN_{a,t}) \tag{132}$$

where,

$PFEN_{a,t}$ = total return on preferred stock (dollars)
$PFES_{a,p,t}$ = value of preferred stock (dollars)
$TOTCAP_{a,p,t}$ = total capitalization (dollars)
$PFER_{a,p,t}$ = coupon rate for preferred stock (fraction) [read as D_PFER]
$APRB_{a,p,t}$ = adjusted pipeline rate base (dollars) [read as D_APRB]
$CMEN_{a,t}$ = total return on common stock equity (dollars)
$CMES_{a,p,t}$ = value of common stock equity (dollars)
$CMER_{a,p,t}$ = common equity rate of return (fraction) [read as D_CMER]
$LTDN_{a,t}$ = total return on long-term debt (dollars)
$LTDS_{a,p,t}$ = value of long-term debt (dollars)
$LTDR_{a,p,t}$ = long-term debt rate (fraction) [read as D_LTDR]
p = pipeline company
a = arc
t = historical year

Note that the first terms (fractions) in parentheses on the right hand side of equations 129 to 131 represent the capital structure ratios for each pipeline company associated with a network arc. These fractions are computed exogenously and read in along with the rates of return and the adjusted rate base. The total returns on preferred stock, common equity, and long-term debt at the arc level are computed immediately after all the input variables are read in. The capital structure ratios are exogenously determined as follows:

$$GPFESTR_{a,p,t} = PFES_{a,p,t} / TOTCAP_{a,p,t} \tag{133}$$

$$GCMESTR_{a,p,t} = CMES_{a,p,t} / TOTCAP_{a,p,t} \tag{134}$$

$$GLTDSTR_{a,p,t} = LTDS_{a,p,t} / TOTCAP_{a,p,t} \tag{135}$$

where,

$GPFESTR_{a,p,t}$ = capital structure ratio for preferred stock for existing pipeline (fraction) [read as D_GPFES]

$GCMESTR_{a,p,t}$ = capital structure ratio for common equity for existing pipeline (fraction) [read as D_GCMES]
$GLTDSTR_{a,p,t}$ = capital structure ratio for long-term debt for existing pipeline (fraction) [read as D_GLTDS]
$PFES_{a,p,t}$ = value of preferred stock (dollars)
$CMES_{a,p,t}$ = value of common stock (dollars)
$LTDS_{a,p,t}$ = value of long-term debt (dollars)
$TOTCAP_{a,p,t}$ = total capitalization (dollars), equal to the sum of value of preferred stock, common stock equity, and long-term debt
p = pipeline company
a = arc
t = historical year

In the financial database, the estimated capital (capitalization) for each interstate pipeline is by definition equal to its adjusted rate base. Hence, the estimated capital $TOTCAP_{a,p,t}$ defined in the above equations is equal to the adjusted rate base $APRB_{a,p,t}$.

$$TOTCAP_{a,p,t} = APRB_{a,p,t} \tag{136}$$

where,

$TOTCAP_{a,p,t}$ = total capitalization (dollars)
$APRB_{a,p,t}$ = adjusted rate base (dollars)
a = arc
p = pipeline company
t = historical year

Substituting the adjusted rate base $APRB_{a,t}$ for the estimated capital $TOTCAP_{a,t}$ in equations 133 to 135, the values of preferred stock, common stock, and long-term debt by pipeline and arc can be computed by applying the capital structure ratios to the adjusted rate base, as follows:

$$\begin{aligned} PFES_{a,p,t} &= GPFESTR_{a,p,t} * APRB_{a,p,t} \\ CMES_{a,p,t} &= GCMESTR_{a,p,t} * APRB_{a,p,t} \\ LTDS_{a,p,t} &= GLTDSTR_{a,p,t} * APRB_{a,p,t} \\ GPFESTR_{a,p,t} &+ GCMESTR_{a,p,t} + GLTDSTR_{a,p,t} = 1.0 \end{aligned} \tag{137}$$

where,

$PFES_{a,p,t}$ = value of preferred stock in nominal dollars
$CMES_{a,p,t}$ = value of common equity in nominal dollars
$LTDS_{a,p,t}$ = long-term debt in nominal dollars
$GPFESTR_{a,p,t}$ = capital structure ratio for preferred stock for existing pipeline (fraction)
$GCMESTR_{a,p,t}$ = capital structure ratio of common stock for existing pipeline (fraction)
$GLTDSTR_{a,p,t}$ = capital structure ratio of long term debt for existing pipeline (fraction)

$APRB_{a,p,t}$ = adjusted rate base (dollars)
p = pipeline
a = arc
t = forecast year

The cost of capital at the arc level ($WAROR_{a,t}$) is computed as the weighted average cost of capital for preferred stock, common stock equity, and long-term debt for all pipeline companies associated with that arc, as follows:

$$WAROR_{a,t} = \sum_{p} [(PFES_{a,p,t} * PFER_{a,p,t} + CMES_{a,p,t} * CMER_{a,p,t} + LTDS_{a,p,t} * LTDR_{a,p,t})] / APRB_{a,t} \quad (138)$$

$$APRB_{a,t} = PFES_{a,t} + CMES_{a,t} + LTDS_{a,t} \quad (139)$$

where,

$WAROR_{a,t}$ = weighted-average after-tax return on capital (fraction)
$PFES_{a,p,t}$ = value of preferred stock (dollars)
$PFER_{a,p,t}$ = preferred stock rate (fraction)
$CMES_{a,p,t}$ = value of common stock equity (dollars)
$CMER_{a,p,t}$ = common equity rate of return (fraction)
$LTDS_{a,p,t}$ = value of long-term debt (dollars)
$LTDR_{a,p,t}$ = long-term debt rate (fraction)
$APRB_{a,p,t}$ = adjusted rate base (dollars)
p = pipeline
a = arc
t = historical year

The adjusted rate base by pipeline and arc is computed as the sum of net plant in service and total cash working capital (which includes plant held for future use, materials and supplies, and other working capital) minus accumulated deferred income taxes. This rate base is computed offline and read in by the PTS. The computation is as follows:

$$APRB_{a,p,t} = NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t} \quad (140)$$

where,

$APRB_{a,p,t}$ = adjusted rate base (dollars)
$NPIS_{a,p,t}$ = net capital cost of plant in service (dollars) [read as D_NPIS]
$CWC_{a,p,t}$ = total cash working capital (dollars) [read as D_CWC]
$ADIT_{a,p,t}$ = accumulated deferred income taxes (dollars) [read as D_ADIT]
p = pipeline company
a = arc
t = historical year

The net plant in service by pipeline and arc is the original capital cost of plant in service minus the accumulated depreciation. It is computed offline and then read in by the PTS. The computation is as follows:

$$NPIS_{a,p,t} = GPIS_{a,p,t} - ADDA_{a,p,t} \tag{141}$$

where,

$NPIS_{a,p,t}$ = net capital cost of plant in service (dollars)
$GPIS_{a,p,t}$ = original capital cost of plant in service (dollars) [read as D_GPIS]
$ADDA_{a,p,t}$ = accumulated depreciation, depletion, and amortization (dollars) [read as D_ADDA]
p = pipeline company
a = arc
t = historical year

The adjusted rate base at the arc level is computed as follows:

$$\begin{aligned} APRB_{a,,t} &= \sum_p APRB_{a,p,t} = \sum_p (NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t}) \\ &= (NPIS_{a,t} + CWC_{a,t} - ADIT_{a,t}) \end{aligned} \tag{142}$$

with,

$$\begin{aligned} NPIS_{a,,t} &= \sum_p (GPIS_{a,p,t} - ADDA_{a,p,t}) \\ &= (GPIS_{a,t} - ADDA_{a,t}) \end{aligned} \tag{143}$$

where,

$APRB_{a,p,t}$ = adjusted rate base (dollars) at the arc level
$NPIS_{a,p,t}$ = net capital cost of plant in service (dollars) at the arc level
$CWC_{a,t}$ = total cash working capital (dollars) at the arc level
$ADIT_{a,t}$ = accumulated deferred income taxes (dollars) at the arc level
$GPIS_{a,p,t}$ = original capital cost of plant in service (dollars) at the arc level
$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization (dollars) at the arc level
p = pipeline company
a = arc
t = historical year

Total Normal Operating Expenses. Total normal operating expense line items include depreciation, taxes, and total operating and maintenance expenses. Total operating and maintenance expenses include administrative and general expenses, customer expenses, and other operating and maintenance expenses. In the PTS, taxes are disaggregated further into Federal, State, and other taxes and deferred income taxes. The equation for total normal operating expenses at the arc level is given as follows:

$$TNOE_{a,t} = \sum_p (DDA_{a,p,t} + TOTAX_{a,p,t} + TOM_{a,p,t}) \tag{144}$$

where,

$TNOE_{a,t}$ = total normal operating expenses (dollars)
$DDA_{a,p,t}$ = depreciation, depletion, and amortization costs (dollars) [read as D_DDA]

$TOTAX_{a,p,t}$ = total Federal and State income tax liability (dollars)
$TOM_{a,p,t}$ = total operating and maintenance expense (dollars) [read as D_TOM]
p = pipeline
a = arc
t = historical year

Depreciation, depletion, and amortization costs, and total operating and maintenance expense are available directly from the financial database. The equations to compute these costs at the arc level are as follows:

$$DDA_{a,t} = \sum_{p} DDA_{a,p,t} \tag{145}$$

$$TOM_{a,t} = \sum_{p} TOM_{a,p,t} \tag{146}$$

Total taxes at the arc level are computed as the sum of Federal and State income taxes, other taxes, and deferred income taxes, as follows:

$$TOTAX_{a,t} = \sum_{p} (FSIT_{a,p,t} + OTTAX_{a,p,t} + DIT_{a,p,t}) \tag{147}$$

$$FSIT_{a,t} = \sum_{p} FSIT_{a,p,t} = \sum_{p} (FIT_{a,p,t} + SIT_{a,p,t}) \tag{148}$$

where,

$TOTAX_{a,t}$ = total Federal and State income tax liability (dollars)
$FSIT_{a,p,t}$ = Federal and State income tax (dollars)
$OTTAX_{a,p,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes and deferred income tax (dollars) [read as D_OTTAX]
$DIT_{a,p,t}$ = deferred income taxes (dollars) [read as D_DIT]
$FIT_{a,p,t}$ = Federal income tax (dollars)
$SIT_{a,p,t}$ = State income tax (dollars)
p = pipeline company
a = arc
t = historical year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the Federal tax rate. The after-tax profit at the arc level is determined as follows:

$$ATP_{a,t} = \sum_{p} (PFER_{a,p,t} * PFES_{a,p,t} + CMER_{a,p,t} * CMES_{a,p,t}) \tag{149}$$

where,

$ATP_{a,t}$ = after-tax profit (dollars) at the arc level
$PFER_{a,p,t}$ = preferred stock rate (fraction)
$PFES_{a,p,t}$ = value of preferred stock (dollars)

$CMER_{a,p,t}$ = common equity rate of return (fraction)
$CMES_{a,p,t}$ = value of common stock equity (dollars)
a = arc
t = historical year

and the Federal income taxes at the arc level are,

$$FIT_{a,t} = \frac{FRATE * ATP_{a,t}}{(1.-FRATE)} \tag{150}$$

where,

$FIT_{a,t}$ = Federal income tax (dollars) at the arc level
FRATE = Federal income tax rate (fraction) (Appendix E)
$ATP_{a,t}$ = after-tax profit (dollars)

State income taxes are computed by multiplying the sum of taxable profit and the associated Federal income tax by a weighted-average State tax rate associated with each pipeline company. The weighted-average State tax rate is based on peak service volumes in each State delivered by the pipeline company. State income taxes at the arc level are computed as follows:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{151}$$

where,

$SIT_{a,t}$ = State income tax (dollars) at the arc level
SRATE = average State income tax rate (fraction) (Appendix E)
$FIT_{a,t}$ = Federal income tax (dollars) at the arc level
$ATP_{a,t}$ = after-tax profits (dollars) at the arc level

Thus, total taxes at the arc level can be expressed by the following equation:

$$TOTAX_{a,t} = (FSIT_{a,t} + OTTAX_{a,t} + DIT_{a,t}) \tag{152}$$

where,

$TOTAX_{a,t}$ = total Federal and State income tax liability (dollars) at the arc level
$FSIT_{a,t}$ = Federal and State income tax (dollars) at the arc level
$OTTAX_{a,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes and deferred income taxes (dollars), at the arc level
$DIT_{a,t}$ = deferred income taxes (dollars) at the arc level
a = arc
t = historical year

All other taxes and deferred income taxes at the arc level are expressed as follows:

$$OTTAX_{a,t} = \sum_{p} OTTAX_{a,p,t} \tag{153}$$

$$DIT_{a,t} = \sum_{p} DIT_{a,p,t} \tag{154}$$

Adjustment from 28 major pipelines to total U.S. Note that all cost-of-service and rate base components computed so far are based on the financial database of 28 major interstate pipelines. According to the U.S. natural gas pipeline construction and financial reports filed with the FERC and published in the Oil and Gas Journal,[86] there were more than 100 interstate natural gas pipelines operating in the United States in 2006. The total annual gross plant in service and operating revenues for all these pipelines are much higher than those for the 28 major interstate pipelines in the financial database. All the cost-of-service and rate base components at the arc level computed in the above sections are scaled up as follows: For the capital costs and adjusted rate base components,

$$\begin{aligned}
GPIS_{a,t} &= GPIS_{a,t} * HFAC_GPIS_t \\
ADDA_{a,t} &= ADDA_{a,t} * HFAC_GPIS_t \\
NPIS_{a,t} &= NPIS_{a,t} * HFAC_GPIS_t \\
CWC_{a,t} &= CWC_{a,t} * HFAC_GPIS_t \\
ADIT_{a,t} &= ADIT_{a,t} * HFAC_GPIS_t \\
APRB_{a,t} &= APRB_{a,t} * HFAC_GPIS_t
\end{aligned} \tag{155}$$

For the cost-of-service components,

$$\begin{aligned}
PFEN_{a,t} &= PFEN_{a,t} * HFAC_REV_t \\
CMEN_{a,t} &= CMEN_{a,t} * HFAC_REV_t \\
LTDN_{a,t} &= LTDN_{a,t} * HFAC_REV_t \\
DDA_{a,t} &= DDA_{a,t} * HFAC_REV_t \\
FSIT_{a,t} &= FSIT_{a,t} * HFAC_REV_t \\
OTTAX_{a,t} &= OTTAX_{a,t} * HFAC_REV_t \\
DIT_{a,t} &= DIT_{a,t} * HFAC_REV_t \\
TOM_{a,t} &= TOM_{a,t} * HFAC_REV_t
\end{aligned} \tag{156}$$

where,

$GPIS_{a,t}$	=	original capital cost of plant in service (dollars)
$HFAC\_GPIS_t$	=	adjustment factor for capital costs to total U.S. (Appendix E)
$ADDA_{a,t}$	=	accumulated depreciation, depletion, and amortization (dollars)
$NPIS_{a,t}$	=	net capital cost of plant in service (dollars)
$CWC_{a,t}$	=	total cash working capital (dollars)
$ADIT_{a,t}$	=	accumulated deferred income taxes (dollars)
$APRB_{a,t}$	=	adjusted pipeline rate base (dollars)
$PFEN_{a,t}$	=	total return on preferred stock (dollars)

[86] *Pipeline Economics*, Oil and Gas Journal, 1994, 1995, 1997, 1999, 2001, 2002, 2003, 2004, 2005, 2006.

$HFAC\_REV_t$ = adjustment factor for operation revenues to total U.S. (Appendix E)
$CMEN_{a,t}$ = total return on common stock equity (dollars)
$LTDN_{a,t}$ = total return on long-term debt (dollars)
$DDA_{a,t}$ = depreciation, depletion, and amortization costs (dollars)
$FSIT_{a,t}$ = Federal and State income tax (dollars)
$OTTAX_{a,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes and deferred income taxes (dollars)
$DIT_{a,t}$ = deferred income taxes (dollars)
$TOM_{a,t}$ = total operations and maintenance expense (dollars)
a = arc
t = historical year

Except for the Federal and State income taxes and returns on capital, all the cost-of-service and rate base components computed at the arc level above are also used as initial values in the forecast year update phase that starts in 2007.

Step 2: Classification of Cost-of-Service Line Items as Fixed and Variable Costs

The PTS breaks each line item of the cost of service (computed in Step 1) into fixed and variable costs. Fixed costs are independent of storage/transportation usage, while variable costs are a function of usage. Fixed and variable costs are computed by multiplying each line item of the cost of service by the percentage of the cost that is fixed and the percentage of the cost that is variable. The classification of fixed and variable costs is defined by the user as part of the scenario specification. The classification of line item cost Ri to fixed and variable cost is determined as follows:

$$R_{i,f} = ALL_f * R_i / 100 \quad (157)$$

$$R_{i,v} = ALL_v * R_i / 100 \quad (158)$$

where,

$R_{i,f}$ = fixed cost portion of line item Ri (dollars)
ALL_f = percentage of line item Ri representing fixed cost
R_i = total cost of line item i (dollars)
$R_{i,v}$ = variable cost portion of line item Ri (dollars)
ALL_v = percentage of line item Ri representing variable cost
i = line item index
f,v = fixed or variable
100 = ALLf + ALLv

An example of this procedure is illustrated in **Table 6-1**.

The resulting fixed and variable costs at the arc level are obtained by summing all line items for each cost category from the above equations, as follows:

$$FC_a = \sum_i R_{i,f} \tag{159}$$

$$VC_a = \sum_i R_{i,v} \tag{160}$$

where,

FC_a = total fixed cost (dollars) at the arc level
VC_a = total variable cost (dollars) at the arc level
a = arc

Table 6-1. Illustration of Fixed and Variable Cost Classification

Cost of Service Line Item	Total (dollars)	Cost Allocation Factors (percent) Fixed	Variable	Cost Component (dollars) Fixed	Variable
Total Return					
Preferred Stock	1,000	100	0	1,000	0
Common Stock	30,000	100	0	30,000	0
Long-Term Debt	29,000	100	0	29,000	0
Normal Operating Expenses					
Depreciation	30,000	100	0	30,000	0
Taxes					
Federal Tax	25,000	100	0	25,000	0
State Tax	5,000	100	0	5,000	0
Other Tax	1,000	100	0	1,000	0
Deferred Income Taxes	1,000	100	0	1,000	0
	105,000	60	40	63,000	42,000
Total Operations & Maintenance					
Total Cost-of-Service	227,000			185,000	42,000

Step 3: Allocation of Fixed and Variable Costs to Rate Components

Allocation of fixed and variable costs to rate components is conducted only for transportation services because storage service is modeled in a more simplified manner using a one-part rate. The rate design to be used within the PTS is specified by input parameters, which can be modified by the user to reflect changes in rate design over time. The PTS allocates the fixed and variable costs computed in Step 2 to rate components as specified by the rate design. For transportation service, the components of the rate consist of a reservation and a usage fee. The reservation fee is a charge assessed based on the amount of capacity reserved. It typically is a monthly fee that does not vary with throughput. The usage fee is a charge assessed for each unit of gas that moves through the system.

The actual reservation and usage fees that pipelines are allowed to charge are regulated by the Federal Energy Regulatory Commission (FERC). How costs are allocated determines the extent of differences in the rates charged for different classes of customers for different types of services. In general, if more fixed costs are allocated to usage fees, more costs are recovered based on throughput.

Costs are assigned either to the reservation fee or to the usage fee according to the rate design specified for the pipeline company. The rate design can vary among pipeline companies. Three typical rate designs are described in **Table 6-2**. The PTS provides two options for specifying the rate design. In the first option, a rate design for each pipeline company can be specified for each forecast year. This option permits different rate designs to be used for different pipeline companies while also allowing individual company rate designs to change over time. Since pipeline company data subsequently are aggregated to network arcs, the composite rate design at the arc-level is the quantity-weighted average of the pipeline company rate designs. The second option permits a global specification of the rate design, where all pipeline companies have the same rate design for a specific time period but can switch to another rate design in a different time period.

Table 6-2. Approaches to Rate Design

Modified Fixed Variable (Three-Part Rate)	**Modified Fixed Variable (Two-Part Rate)**	**Straight Fixed Variable (Two-Part Rate)**
● Two-part reservation fee. - Return on equity and related taxes are held at risk to achieving throughput targets by allocating these costs to the usage fee. Of the remaining fixed costs, 50 percent are recovered from a peak day reservation fee and 50 percent are recovered through an annual reservation fee.	● Reservation fee based on peak day requirements - all fixed costs except return on equity and related taxes recovered through this fee.	● One-part capacity reservation fee. All fixed costs are recovered through the reservation fee, which is assessed based on peak day capacity requirements.
● Variable costs allocated to the usage fee. In addition, return on equity and related taxes are also recovered through the usage fee.	● Variable costs plus return on equity and related taxes are recovered through the usage fee.	● Variable costs are recovered through the usage fee.

The allocation of fixed costs to reservation and usage fees entails multiplying each fixed cost line item of the total cost of service by the corresponding fixed cost rate design classification factor. A similar process is carried out for variable costs. This procedure is illustrated in **Tables 6-3a and 6-3b** and is generalized in the equations that follow. The classification of transportation line item costs $R_{i,f}$ and $R_{i,v}$ to reservation and usage cost is determined as follows:

$$R_{i,f,r} = ALL_{f,r} * R_{i,f} / 100 \tag{161}$$

$$R_{i,f,u} = ALL_{f,u} * R_{i,f} / 100 \tag{162}$$

$$R_{i,v,r} = ALL_{v,r} * R_{i,v} / 100 \tag{163}$$

$$R_{i,v,u} = ALL_{v,u} * R_{i,v} / 100 \tag{164}$$

Table 6-3a. Illustration of Allocation of Fixed Costs to Rate Components

Cost of Service Line Item	Total (dollars)	Allocation Factors (percent) Reservation	Usage	Cost Assigned to Rate Component (dollars) Reservation	Usage
Total Return					
Preferred Stock	1,000	100	0	0	1,000
Common Stock	30,000	100	0	0	30,000
Long-Term Debt	29,000	100	0	29,000	0
Normal Operating Expenses					
Depreciation	30,000	100	0	30,000	0
Taxes					
Federal Tax	25,000	0	100	0	25,000
State Tax	5,000	0	100	0	5,000
Other Tax	1,000	100	0	1,000	0
Deferred Income Taxes	1,000	100	0	1,000	0
Total Operations & Maintenance	63,000	100	0	63,000	0
Total Cost-of-Service	185,000			124,000	61,000

Table 6-3b. Illustration of Allocation of Variable Costs to Rate Components

Cost of Service Line Item	Total (dollars)	Allocation Factors (percent) Reservation	Usage	Cost Assigned to Rate Component (dollars) Reservation	Usage
Total Return					
Preferred Stock	0	0	100	0	0
Common Stock	0	0	100	0	0
Long-Term Debt	0	0	100	0	0
Normal Operating Expenses					
Depreciation	0	0	100	0	0
Taxes					
Federal Tax	0	0	100	0	0
State Tax	0	0	100	0	0
Other Tax	0	0	100	0	0
Deferred Income Taxes	0	0	100	0	0
Total Operations & Maintenance	42,000	0	100	0	42,000
Total Cost-of-Service	42,000			0	42,000

where,

R = line item cost (dollars)

ALL = percentage of reservation or usage line item R representing fixed or variable cost (Appendix E -- AFR, AVR, AFU=1-AFR, AVU=1-AVR)

100 = $ALL_{f,r} + ALL_{f,u}$

$$100 = ALL_{v,r} + ALL_{v,u}$$
i = line item number index
f = fixed cost index
v = variable cost index
r = reservation cost index
u = usage cost index

At this stage in the procedure, the line items comprising the fixed and variable cost components of the reservation and usage fees can be summed to obtain total reservation and usage components of the rates.

$$RCOST_a = \sum_i (R_{i,f,r} + R_{i,v,r}) \tag{165}$$

$$UCOST_a = \sum_i (R_{i,f,u} + R_{i,v,u}) \tag{166}$$

where,

$RCOST_a$ = total reservation cost (dollars) at the arc level
$UCOST_a$ = total usage cost (dollars) at the arc level
a = arc

After ratemaking Steps 1, 2 and 3 are completed for each arc by historical year, the rates are computed below.

Computation of Rates for Historical Years

The reservation and usage costs-of-service (RCOST and UCOST) developed above are used separately to develop two types of rates at the arc level: *variable tariffs* and *annual fixed usage fees*.

Variable Tariff Curves

Variable tariffs are proportional to reservation charges and are broken up into peak and off-peak time periods. Variable tariffs are derived directly from variable tariff curves which are developed based on reservation costs, utilization rates, annual flows, and other parameters.

In the PTS code, these variable tariff curves are defined by FUNCTION (NGPIPE_VARTAR) which is used by the ITS to compute the variable peak and off-peak tariffs by arc and by forecast year. The pipeline tariff curves are a function of peak or off-peak flow and are specified using a base point [price and quantity (PNOD, QNOD)] and an assumed price elasticity, as follows:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA\_PIPE} \tag{167}$$

such that,

For peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR\_YR}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{168}$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \tag{169}$$

For off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{170}$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \tag{171}$$

where,

$NGPIPE\_VARTAR_{a,t}$	=	function to define pipeline tariffs (87$/Mcf)
$PNOD_{a,t}$	=	base point, price (87$/Mcf)
$QNOD_{a,t}$	=	base point, quantity (Bcf)
$Q_{a,t}$	=	flow along pipeline arc (Bcf), dependent variable for the function
ALPHA_PIPE	=	price elasticity for pipeline tariff curve for current capacity
$RCOST_{a,t}$	=	reservation cost-of-service (dollars)
$PTNETFLOW_{a,t}$	=	natural gas network flow (throughput, Bcf)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	historical year

Annual Fixed Usage Fees

The annual fixed usage fees (volumetric charges) are derived directly from the usage costs, utilization rates for peak and off-peak time periods, and annual arc capacity. These fees are computed as the average fees over each historical year, as follows:

$$FIXTAR_{a,t} = UCOST_{a,t} / [(PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_t] \tag{172}$$

where,

$FIXTAR_{a,t}$	=	annual fixed usage fees for existing and new capacity (87$/Mcf)
$UCOST_{a,t}$	=	annual usage cost of service for existing and new capacity (dollars)

PKSHR_YR	=	portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$	=	peak pipeline utilization (fraction)
$PTCURPCAP_{a,t}$	=	current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$	=	off-peak pipeline utilization (fraction)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	historical year

Canadian Tariffs

In the historical year phase, Canadian tariffs are set to the historical differences between the import prices and the Western Canada Sedimentary Basin (WCSB) wellhead price.

Computation of Storage Rates

The annual storage tariff for each NGTDM region and year is defined as a function of storage flow and is specified using a base point [price and quantity (PNOD, QNOD)] and an assumed price elasticity, as follows:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA\_STR} \quad (173)$$

such that,

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC\_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP\_ADJ_{r,t} * ADJ\_STR \quad (174)$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \quad (175)$$

where,

$X1NGSTR\_VARTAR_{r,t}$	=	function to define storage tariffs (87$/Mcf)
$Q_{r,t}$	=	peak period net storage withdrawals (Bcf)
$PNOD_{r,t}$	=	base point, price (87$/Mcf)
$QNOD_{r,t}$	=	base point, quantity (Bcf)
ALPHA_STR	=	price elasticity for storage tariff curve (ratio, Appendix E)
$STCOS_{r,t}$	=	existing storage capacity cost of service, computed from historical cost-of-service components
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
$STRATIO_{r,t}$	=	portion of revenue requirement obtained by moving gas from the off-peak to the peak period (fraction, Appendix E)
$STCAP\_ADJ_{r,t}$	=	adjustment factor for the cost of service to total U.S. (ratio), defined as annual storage working gas capacity divided by

		Foster storage working gas capacity
ADJ_STR	=	storage tariff curve adjustment factor (fraction, Appendix E)
$PTSTUTZ_{r,t}$	=	storage utilization (fraction)
$PTCURPSTR_{r,t}$	=	annual storage working gas capacity (Bcf)
r	=	NGTDM region
t	=	historical year

Forecast Year Update Phase

The purpose of the forecast year update phase is to project, for each arc and subsequent year of the forecast period, the cost-of-service components that are used to develop rates for the peak and off-peak periods. For each year, the PTS forecasts the adjusted rate base, cost of capital, return on rate base, depreciation, taxes, and operation and maintenance expenses. The forecasting relationships are discussed in detail below.

After all of the components of the cost-of-service at the arc level are forecast, the PTS proceeds to: (1) classify the components of the cost of service as fixed and variable costs, (2) allocate fixed and variable costs to rate components (reservation and usage costs) based on the rate design, and (3) compute arc-specific rates (variable and fixed tariffs) for peak and off-peak periods.

Investment Costs for Generic Pipelines

The PTS projects the capital costs to expand pipeline capacity at the arc level, as opposed to determining the costs of expansion for individual pipelines. The PTS represents arc-specific generic pipelines to generate the cost of capacity expansion by arc. Thus, the PTS tracks costs attributable to capacity added during the forecast period separately from the costs attributable to facilities in service in the historical years. The PTS estimates the capital costs associated with the level of capacity expansion forecast by the ITS in the previous forecast year based on exogenously specified estimates for the average pipeline capital costs at the arc level ($AVG\_CAPCOST_a$) associated with expanding capacity for compression, looping, and new pipeline. These average capital costs per unit of expansion (2005 dollars per Mcf) were computed based on a pipeline construction project cost database[87] compiled by the Office of Oil and Gas. These costs are adjusted for inflation from 2007 throughout the forecast period (i.e., they are held constant in real terms).

The average capital cost to expand capacity on a network arc is estimated given the level of capacity additions in year t provided by the ITS and the associated assumed average unit capital cost. This average unit capital cost represents the investment cost for a generic pipeline associated with a given arc, as follows:

$$CCOST_{a,t} = AVG\_CAPCOST_a * MC\_PCWGDP_t / MC\_PCWGDP_{2000} \qquad (176)$$

[87] A spreadsheet compiled by James Tobin of EIA's Office of Oil and Gas containing historical and proposed state-to-state pipeline construction project costs, mileage, and capacity levels and additions by year from 1996 to 2011, by pipeline company (data as of August 16, 2007).

where,

$CCOST_{a,t}$ = average pipeline capital cost per unit of expanded capacity (nominal dollars per Mcf)
$AVG\_CAPCOST_a$ = average pipeline capital cost per unit of expanded capacity in 2000 dollars per Mcf (Appendix E, AVGCOST)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

The new capacity expansion expenditures allowed in the rate base within a forecast year are derived from the above average unit capital cost and the amount of incremental capacity additions determined by the ITS for each arc, as follows:

$$NCAE_{a,t} = CCOST_{a,t} * CAPADD_{a,t} * 1{,}000{,}000 * (1 + PCNT\_R) \qquad (177)$$

where,

$NCAE_{a,t}$ = capital cost to expand capacity on a network arc (dollars)
$CCOST_{a,t}$ = average capital cost per unit of expansion (dollars per Mcf)
$CAPADD_{a,t}$ = capacity additions for an arc as determined in the ITS (Bcf/yr)
$PCNT\_R$ = assumed average percentage (fraction) for pipeline replacement costs (Appendix E)
t = forecast year

To account for additional costs due to pipeline replacements, the PTS increases the capital costs to expand capacity by a small percentage (PCNT_R). Once the capital cost of new plant in service is computed by arc in year t, this amount is used in an accounting algorithm for the computation of gross plant in service for new capacity expansion, along with its depreciation, depletion, and amortization. These will in turn be used in the computation of updated cost-of-service components for the existing and new capacity for an arc.

Forecasting Cost-of-Service [88]

The primary purpose in forecasting cost-of-service is to capture major changes in the composition of the revenue requirements and major changes in cost trends through the forecast period. These changes may be caused by capacity expansion or maintenance and life extension of nearly depreciated plants, as well as by changes in the cost and availability of capital.

The projection of the cost-of-service is approached from the viewpoint of a long-run marginal cost analysis for gas pipeline systems. This differs from the determination of cost-of-service for the purpose of a rate case. Costs that are viewed as fixed for the purposes of a rate case actually vary in the long-run with one or more external measures of size or activity levels in the industry. For example, capital investments for replacement and refurbishment of existing facilities are a long-run marginal cost of the pipeline system. Once in place,

[88] All cost components in the forecast equations in this section are in nominal dollars, unless explicitly stated otherwise.

however, the capital investments are viewed as fixed costs for the purposes of rate cases. The same is true of operations and maintenance expenses that, except for short-run variable costs such as fuel, are most commonly classified as fixed costs in rate cases. For example, customer expenses logically vary over time based on the number of customers served and the cost of serving each customer. The unit cost of serving each customer, itself, depends on changes in the rate base and individual cost-of-service components, the extent and/or complexity of service provided to each customer, and the efficiency of the technology level employed in providing the service.

The long-run marginal cost approach generally projects total costs as the product of unit cost for the activity multiplied by the incidence of the activity. Unit costs are projected from cost-of-service components combined with time trends describing changes in level of service, complexity, or technology. The level of activity is projected in terms of variables external to the PTS (e.g., annual throughput) that are both logically and empirically related to the incurrence of costs. Implementation of the long-run marginal cost approach involves forecasting relationships developed through empirical studies of historical change in pipeline costs, accounting algorithms, exogenous assumptions, and inputs from other NEMS modules. These forecasting algorithms may be classified into three distinct areas, as follows:

- The projection of adjusted rate base and cost of capital for the combined existing and new capacity.
- The projection of components of the revenue requirements.
- The computation of variable and fixed rates for peak and off-peak periods.

The empirically derived forecasting algorithms discussed below are determined for each network arc.

Projection of Adjusted Rate Base and Cost of Capital

The approach for projecting adjusted rate base and cost of capital at the arc level is summarized in **Table 6-4**. Long-run marginal capital costs of pipeline companies reflect changes in the AA utility bond index rate. Once projected, the adjusted rate base is translated into capital-related components of the revenue requirements based on projections of the cost of capital, total operating and maintenance expenses, and algorithms for depreciation and tax effects.

The projected adjusted rate base for the combined existing and new pipelines at the arc level in year t is computed as the amount of gross plant in service in year t minus previous year's accumulated depreciation, depletion, and amortization plus total cash working capital minus accumulated deferred income taxes in year t.

$$APRB_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} + CWC_{a,t} - ADIT_{a,t} \qquad (178)$$

where,

$APRB_{a,t}$ = adjusted rate base in dollars
$GPIS_{a,t}$ = total capital cost of plant in service (gross plant in service) in dollars

Table 6-4. Approach to Projection of Rate Base and Capital Costs

Projection Component	Approach
1. Adjusted Rate Base	
a. Gross plant in service in year t	
I. Capital cost of existing plant in service	Gross plant in service in the last historical year (2006)
II. Capacity expansion costs for new capacity	Accounting algorithm [equation 180]
b. Accumulated Depreciation, Depletion & Amortization	Accounting algorithm [equations 186, 187, 189] and empirically estimated for existing capacity [equation 188]
c. Cash and other working capital	User defined option for the combined existing and new capacity [equation 190]
d. Accumulated deferred income taxes	Empirically estimated for the combined existing and new capacity [equation 141]
f. Depreciation, depletion, and amortization	Existing Capacity: empirically estimated [equation 188] New Capacity: accounting algorithm [equation 189]
2. Cost of Capital	
a. Long-term debt rate	Projected AA utility bond yields adjusted by historical average deviation constant for long-term debt rate
b. Preferred equity rate	Projected AA utility bond yields adjusted by historical average deviation constant for preferred equity rate
c. Common equity return	Projected AA utility bond yields adjusted by historical average deviation constant for common equity return
3. Capital Structure	Held constant at average historical values

$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
$CWC_{a,t}$ = total cash working capital including other cash working capital in dollars
$ADIT_{a,t}$ = accumulated deferred income taxes in dollars
a = arc
t = forecast year

All the variables in the above equation represent the aggregate variables for all interstate pipelines associated with an arc. The aggregate variables on the right hand side of the adjusted rate base equation are forecast by the equations below. First, total (existing and new) gross plant in service in the forecast year is determined as the sum of existing gross plant in service and new capacity expansion expenditures added to existing gross plant in service. New capacity expansion can be compression, looping, and new pipelines. For simplification, the replacement, refurbishment, retirement, and cost associated with new facilities for complying with Order 636 are not accounted for in projecting total gross plant in service in year t. Total gross plant in service for a network arc is forecast as follows:

$$GPIS_{a,t} = GPIS\_E_{a,t} + GPIS\_N_{a,t} \quad (179)$$

where,

$GPIS_{a,t}$ = total capital cost of plant in service (gross plant in service) in dollars
$GPIS\_E_{a,t}$ = gross plant in service in the last historical year (2006)
$GPIS\_N_{a,t}$ = capital cost of new plant in service in dollars
a = arc
t = forecast year

In the above equation, the capital cost of existing plant in service ($GPIS\_E_{a,t}$) reflects the amount of gross plant in service in the last historical year (2006). The capital cost of new plant in service ($GPIS\_N_{a,t}$) in year t is computed as the accumulated new capacity expansion expenditures from 2007 to year t and is determined by the following equation:

$$GPIS\_N_{a,t} = \sum_{s=2004}^{t} NCAE_{a,s} \quad (180)$$

where,

$GPIS\_N_{a,t}$ = gross plant in service for new capacity expansion in dollars
$NCAE_{a,s}$ = new capacity expansion expenditures occurring in year s after 2006 (in dollars) [equation 177]
s = the year new expansion occurred
a = arc
t = forecast year

Next, net plant in service in year t is determined as the difference between total capital cost of plant in service (gross plant in service) in year t and previous year's accumulated depreciation, depletion, and amortization.

$$NPIS_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} \quad (181)$$

where,

$NPIS_{a,t}$ = total net plant in service in dollars
$GPIS_{a,t}$ = total capital cost of plant in service (gross plant in service) in dollars
$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
a = arc
t = forecast year

Accumulated depreciation, depletion, and amortization for the combined existing and new capacity in year t is determined by the following equation:

$$ADDA_{a,t} = ADDA\_E_{a,t} + ADDA\_N_{a,t} \quad (182)$$

where,

$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
$ADDA\_E_{a,t}$ = accumulated depreciation, depletion, and amortization for existing capacity in dollars
$ADDA\_N_{a,t}$ = accumulated depreciation, depletion, and amortization for new capacity in dollars
a = arc
t = forecast year

With this and the relationship between the capital costs of existing and new plants in service from equation 179, total net plant in service ($NPIS_{a,t}$) is set equal to the sum of net plant in service for existing pipelines and new capacity expansions, as follows:

$$NPIS_{a,t} = NPIS\_E_{a,t} + NPIS\_N_{a,t} \tag{183}$$

$$NPIS\_E_{a,t} = GPIS\_E_{a,t} - ADDA\_E_{a,t-1} \tag{184}$$

$$NPIS\_N_{a,t} = GPIS\_N_{a,t} - ADDA\_N_{a,t-1} \tag{185}$$

where,

$NPIS_{a,t}$ = total net plant in service in dollars
$NPIS\_E_{a,t}$ = net plant in service for existing capacity in dollars
$NPIS\_N_{a,t}$ = net plant in service for new capacity in dollars
$GPIS\_E_{a,t}$ = gross plant in service in the last historical year (2006)
$ADDA\_E_{a,t}$ = accumulated depreciation, depletion, and amortization for existing capacity in dollars
$ADDA\_N_{a,t}$ = accumulated depreciation, depletion, and amortization for new capacity in dollars
GPIS_N = gross plant in service for new capacity in dollars
a = arc
t = forecast year

Accumulated depreciation, depletion, and amortization for a network arc in year t is determined as the sum of previous year's accumulated depreciation, depletion, and amortization and current year's depreciation, depletion, and amortization.

$$ADDA_{a,t} = ADDA_{a,t-1} + DDA_{a,t} \tag{186}$$

where,

$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
$DDA_{a,t}$ = annual depreciation, depletion, and amortization costs in dollars
a = arc
t = forecast year

Annual depreciation, depletion, and amortization for a network arc in year t equal the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with the arc.

$$DDA_{a,t} = DDA\_E_{a,t} + DDA\_N_{a,t} \quad (187)$$

where,

$DDA_{a,t}$ = annual depreciation, depletion, and amortization in dollars
$DDA\_E_{a,t}$ = depreciation, depletion, and amortization costs for existing capacity in dollars
$DDA\_N_{a,t}$ = depreciation, depletion, and amortization costs for new capacity in dollars
a = arc
t = forecast year

A regression equation is used to determine the annual depreciation, depletion, and amortization for existing capacity associated with an arc, while an accounting algorithm is used for new capacity. For existing capacity, this expense is forecast as follows:

$$DDA\_E_{a,t} = \beta_{0,a} + \beta_1 * NPIS\_E_{a,t-1} + \beta_2 * NEWCAP\_E_{a,t} \quad (188)$$

where,

$DDA\_E_{a,t}$ = annual depreciation, depletion, and amortization costs for existing capacity in nominal dollars
$\beta_{0,a}$ = DDA_C_a, constant term estimated by arc (Appendix F, Table F3.3, $\beta_{0,a} = B\_ARC_{xx\_yy}$)
β_1 = DDA_NPIS, estimated coefficient for net plant in service for existing capacity (Appendix F, Table F3.3)
β_2 = DDA_NEWCAP, estimated coefficient for the change in gross plant in service for existing capacity (Appendix F, Table F3.3)
$NPIS\_E_{a,t}$ = net plant in service for existing capacity (dollars)
$NEWCAP\_E_{a,t}$ = change in gross plant in service for existing capacity between t and t-1 (dollars)
a = arc
t = forecast year

The accounting algorithm used to define the annual depreciation, depletion, and amortization for new capacity assumes straight-line depreciation over a 30-year life, as follows:

$$DDA\_N_{a,t} = GPIS\_N_{a,t} / 30 \quad (189)$$

where,

$DDA\_N_{a,t}$ = annual depreciation, depletion, and amortization for new capacity in dollars
$GPIS\_N_{a,t}$ = gross plant in service for new capacity in dollars [equation 180]
30 = 30 years of plant life
a = arc
t = forecast year

Next, total cash working capital ($CWC_{a,t}$) for the combined existing and new capacity by arc in the adjusted rate base equation consists of cash working capital, material and supplies, and other components that vary by company. Total cash working capital for pipeline transmission for existing and new capacity at the arc level is deflated using the chain weighted GDP price index with 2005 as a base. This level of cash working capital ($R\_CWC_{a,t}$) is determined using a log-linear specification with correction for serial correlation given the economies in cash management in gas transmission. The estimated equation used for R_CWC (Appendix F, Table F3) is determined as a function of total operation and maintenance expenses, as defined below:

$$R\_CWC_{a,t} = CWC\_K * e^{(\beta_{0,a}*(1-\rho)+CWC\_TOM*\log(R\_TOM_{a,t})+\rho*\log(R\_CWC_{a,t-1})-\rho*CWC\_TOM*\log(R\_TOM_{a,t-1}))} \quad (190)$$

where,

$R\_CWC_{a,t}$	=	total pipeline transmission cash working capital for existing and new capacity (2005 real dollars)
$\beta_{0,a}$	=	CWC_C_a, estimated arc specific constant for gas transported from node to node (Appendix F, Table F3.2, $\beta_{0,a} = B\_ARC_{xx\_yy}$)
CWC_TOM	=	estimated R_TOM coefficient (Appendix F, Table F3.2)
$R\_TOM_{a,t}$	=	total operation and maintenance expenses in 2005 real dollars
CWC_K	=	correction factor estimated in stage 2 of the regression equation estimation process (Appendix F, Table F3)
ρ	=	autocorrelation coefficient from estimation (Appendix F, Table F3.2 -- CWC_RHO)
a	=	arc
t	=	forecast year

Last, the level of accumulated deferred income taxes for the combined existing and new capacity on a network arc in year t in the adjusted rate base equation depends on income tax regulations in effect, differences in tax and book depreciation, and the time vintage of past construction. The level of accumulated deferred income taxes for the combined existing and new capacity is derived as follows:

$$ADIT_{a,t} = \beta_{0,a} + \beta_1 * NEWCAP_{a,t} + \beta_2 * NEWCAP_{a,t} + \beta_3 * NEWCAP_{a,t} + ADIT_{a,t-1} \quad (191)$$

where,

$ADIT_{a,t}$	=	accumulated deferred income taxes in dollars
$\beta_{0,a}$	=	ADIT_Ca, constant term estimated by arc (Appendix F, Table F3.5, $\beta_{0,a} = B\_ARC_{xx\_yy}$)
β_1	=	BNEWCAP_PRE2003, estimated coefficient on the change in gross plant in service in the pre-2003 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
β_2	=	BNEWCAP_2003_2004, estimated coefficient on the change in gross plant in service for the years 2003/2004 because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.

β_3 = BNEWCAP_POST2004, estimated coefficient on the change in gross plant in service in the post-2004 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
$NEWCAP_{a,t}$ = change in gross plant in service for the combined existing and new capacity between years t and t-1 (in dollars)
a = arc
t = forecast year

Cost of capital. The capital-related components of the revenue requirement at the arc level depend upon the size of the adjusted rate base and the cost of capital to the pipeline companies associated with that arc. In turn, the company level costs of capital depend upon the rates of return on debt, preferred stock and common equity, and the amounts of debt and equity in the overall capitalization. Cost of capital for a company is the weighted average after-tax rate of return (WAROR) which is a function of long-term debt, preferred stock, and common equity. The rate of return variables for preferred stock, common equity, and debt are related to forecast macroeconomic variables. For the combined existing and new capacity at the arc level, it is assumed that these rates will vary as a function of the yield on AA utility bonds (provided by the Macroeconomic Activity Module as a percent) in year t adjusted by a historical average deviation constant, as follows:

$$PFER_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_PFER_a \tag{192}$$

$$CMER_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_CMER_a \tag{193}$$

$$LTDR_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_LTDR_a \tag{194}$$

where,

$PFER_{a,t}$ = rate of return for preferred stock
$CMER_{a,t}$ = common equity rate of return
$LTDR_{a,t}$ = long-term debt rate
$MC\_RMPUAANS_t$ = AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPPUAA, percentage)
ADJ_PFER_a = historical average deviation constant (fraction) for rate of return for preferred stock (1994-2003, over 28 major gas pipeline companies) (D_PFER/100., Appendix E)
ADJ_CMER_a = historical average deviation constant (fraction) for rate of return for common equity (1994-2003, over 28 major gas pipeline companies) (D_CMER/100., Appendix E)
ADJ_LTDR_a = historical average deviation constant (fraction) for long term debt rate (1994-2003, over 28 major gas pipeline companies) (D_LTDR/100., Appendix E)
a = arc
t = forecast year

The weighted average cost of capital in the forecast year is computed as the sum of the capital-weighted rates of return for preferred stock, common equity, and debt, as follows:

$$WAROR_{a,t} = \frac{(PFER_{a,t} * PFES_{a,t}) + (CMER_{a,t} * CMES_{a,t}) + (LTDR_{a,t} * LTDS_{a,t})}{TOTCAP_{a,t}} \quad (195)$$

$$TOTCAP_{a,t} = (PFES_{a,t} + CMES_{a,t} + LTDS_{a,t}) \quad (196)$$

where,

$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$ = rate or return for preferred stock (fraction)
$PFES_{a,t}$ = value of preferred stock (dollars)
$CMER_{a,t}$ = common equity rate of return (fraction)
$CMES_{a,t}$ = value of common stock (dollars)
$LTDR_{a,t}$ = long-term debt rate (fraction)
$LTDS_{a,t}$ = value of long-term debt (dollars)
$TOTCAP_{a,t}$ = sum of the value of long-term debt, preferred stock, and common stock equity dollars)
a = arc
t = forecast year

The above equation can be written as a function of the rates of return and capital structure ratios as follows:

$$WAROR_{a,t} = (PFER_{a,t} * GPFESTR_{a,t}) + (CMER_{a,t} * GCMESTR_{a,t}) + (LTDR_{a,t} * GLTDSTR_{a,t}) \quad (197)$$

where,

$$GPFESTR_{a,t} = PFES_{a,t} / TOTCAP_{a,t} \quad (198)$$

$$GCMESTR_{a,t} = CMES_{a,t} / TOTCAP_{a,t} \quad (199)$$

$$GLTDSTR_{a,t} = LTDS_{a,t} / TOTCAP_{a,t} \quad (200)$$

and,

$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$ = coupon rate for preferred stock (fraction)
$CMER_{a,t}$ = common equity rate of return (fraction)
$LTDR_{a,t}$ = long-term debt rate (fraction)
$GPFESTR_a$ = ratio of preferred stock to estimated capital for existing and new capacity (fraction) [referred to as capital structure for preferred stock]
$GCMESTR_a$ = ratio of common stock to estimated capital for existing and new capacity (fraction)[referred to as capital structure for common stock]
$GLTDSTR_a$ = ratio of long term debt to estimated capital for existing and new capacity (fraction)[referred to as capital structure for long term debt]
$PFES_{a,t}$ = value of preferred stock (dollars)
$CMES_{a,t}$ = value of common stock (dollars)
$LTDS_{a,t}$ = value of long-term debt (dollars)

$TOTCAP_{a,t}$ = estimated capital equal to the sum of the value of preferred stock, common stock equity, and long-term debt (dollars)
a = arc
t = forecast year

In the financial database, the estimated capital for each interstate pipeline is by definition equal to its adjusted rate base. Hence, the estimated capital ($TOTCAP_{a,t}$) defined in equation 196 is equal to the adjusted rate base ($APRB_{a,t}$) defined in equation 178:

$$TOTCAP_{a,t} = APRB_{a,t} \tag{201}$$

where,

$TOTCAP_{a,t}$ = estimated capital in dollars
$APRB_{a,t}$ = adjusted rate base in dollars
a = arc
t = forecast year

Substituting the adjusted rate base variable $APRB_{a,t}$ for the estimated capital $TOTCAP_{a,t}$ in equations 198 to 200, the values of preferred stock, common stock, and long term debt by arc can be derived as functions of the capital structure ratios and the adjusted rate base. Capital structure is the percent of total capitalization (adjusted rate base) represented by each of the three capital components: preferred equity, common equity, and long-term debt. The percentages of total capitalization due to common stock, preferred stock, and long-term debt are considered fixed throughout the forecast. Assuming that the total capitalization fractions remain the same over the forecast horizon, the values of preferred stock, common stock, and long-term debt can be derived as follows:

$$\begin{aligned} PFES_{a,t} &= GPFESTR_a * APRB_{a,t} \\ CMES_{a,t} &= GCMESTR_a * APRB_{a,t} \\ LTDS_{a,t} &= GLTDSTR_a * APRB_{a,t} \end{aligned} \tag{202}$$

where,

$PFES_{a,t}$ = value of preferred stock in nominal dollars
$CMES_{a,t}$ = value of common equity in nominal dollars
$LTDS_{a,t}$ = long-term debt in nominal dollars
$GPFESTR_a$ = ratio of preferred stock to adjusted rate base for existing and new capacity (fraction) [referred to as capital structure for preferred stock]
$GCMESTR_a$ = ratio of common stock to adjusted rate base for existing and new capacity (fraction)[referred to as capital structure for common stock]
$GLTDSTR_a$ = ratio of long term debt to adjusted rate base for existing and new capacity (fraction)[referred to as capital structure for long term debt]
$APRB_{a,t}$ = adjusted pipeline rate base (dollars)
a = arc
t = forecast year

In the forecast year update phase, the capital structures ($GPFESTR_a$, $GCMESTR_a$, and $GLTDSTR_a$) at the arc level in the above equations are held constant over the forecast period. They are defined below as the average adjusted rate base weighted capital structures over all pipelines associated with an arc and over the historical time period (1997-2006).

$$GPFESTR_a = \frac{\sum_{t=1997}^{2006} \sum_{p} (GPFESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_{p} APRB_{a,p,t}} \tag{203}$$

$$GCMESTR_a = \frac{\sum_{t=1997}^{2006} \sum_{p} (GCMESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_{p} APRB_{a,p,t}} \tag{204}$$

$$GLTDSTR_a = \frac{\sum_{t=1997}^{2006} \sum_{p} (GLTDSTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_{p} APRB_{a,p,t}} \tag{205}$$

where,

$GPFESTR_a$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$GCMESTR_a$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$GLTDSTR_a$	=	historical average capital structure for long term debt for existing and new capacity (fraction), held constant over the forecast period
$GPFESTR_{a,p,t}$	=	capital structure for preferred stock (fraction) by pipeline company in the historical years (1997-2006) (Appendix E, D_PFES)
$GCMESTR_{a,p,t}$	=	capital structure for common stock (fraction) by pipeline company in the historical years (1997-2006) (Appendix E, D_CMES)
$GLTDSTR_{a,p,t}$	=	capital structure for long term debt (fraction) by pipeline company in the historical years (1997-2006) (Appendix E,D_LTDS)
$APRB_{a,p,t}$	=	adjusted rate base (capitalization) by pipeline company in the historical years (1997-2006) (Appendix E, D_APRB)
p	=	pipeline company
a	=	arc
t	=	historical year

The weighted average cost of capital in the forecast year in equation 197 is forecast as follows:

$$WAROR_{a,t} = (PFER_{a,t} * GPFESTR_{a}) + (CMER_{a,t} * GCMESTR_{a}) + (LTDR_{a,t} * GLTDSTR_{a}) \quad (206)$$

where,

$WAROR_{a,t}$	=	weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$	=	coupon rate for preferred stock (fraction), function of AA utility bond rate [equation 192]
$CMER_{a,t}$	=	common equity rate of return (fraction), function of AA utility bond rate [equation 193]
$LTDR_{a,t}$	=	long-term debt rate (fraction), function of AA utility bond rate [equation 194]
$GPFESTR_{a}$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$GCMESTR_{a}$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$GLTDSTR_{a}$	=	historical average capital structure for long term debt for existing and new capacity (fraction), held constant over the forecast period
a	=	arc
t	=	forecast year

The weighted-average after-tax rate of return on capital ($WAROR_{a,t}$) is applied to the adjusted rate base ($APRB_{a,t}$) to project the total return on rate base (after taxes), also known as the after-tax operating income, which is a major component of the revenue requirement.

Projection of Revenue Requirement Components

The approach to the projection of revenue requirement components is summarized in **Table 6-5**. Given the rate base, rates of return, and capitalization structure projections discussed above, the revenue requirement components are relatively straightforward to project. The capital-related components include total return on rate base (after taxes); Federal and State income taxes; deferred income taxes; other taxes; and depreciation, depletion, and amortization costs. Other components include total operating and maintenance expenses, and regulatory amortization, which is small and thus assumed to be negligible in the forecast period. The total operating and maintenance expense variable includes expenses for transmission of gas for others; administrative and general expenses; and sales, customer accounts and other expenses. The total cost of service (revenue requirement) at the arc level for a forecast year is determined as follows:

$$TCOS_{a,t} = TRRB_{a,t} + DDA_{a,t} + TOTAX_{a,t} + TOM_{a,t} \quad (207)$$

where,

Table 6-5. Approach to Projection of Revenue Requirements

Projection Component	**Approach**
1. Capital-Related Costs	
a. Total return on rate base	Direct calculation from projected rate base and rates of return
b. Federal/State income taxes	Accounting algorithms based on tax rates
c. Deferred income taxes	Difference in the accumulated deferred income taxes between years t and t-1
2. Depreciation, Depletion, and Amortization	Estimated equation and accounting algorithm
3. Total Operating and Maintenance Expenses	Estimated equation
4. Other Taxes	Previous year's other taxes adjusted to inflation rate and growth in capacity

$TCOS_{a,t}$ = total cost-of-service or revenue requirement for existing and new capacity (dollars)
$TRRB_{a,t}$ = total return on rate base for existing and new capacity after taxes (dollars)
$DDA_{a,t}$ = depreciation, depletion, and amortization for existing and new capacity (dollars)
$TOTAX_{a,t}$ = total Federal and State income tax liability for existing and new capacity (dollars)
$TOM_{a,t}$ = total operating and maintenance expenses for existing and new capacity (dollars)
a = arc
t = forecast year

The total return on rate base for existing and new capacity is computed from the projected weighted cost of capital and estimated rate base, as follows:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \tag{208}$$

where,

$TRRB_{a,t}$ = total return on rate base (after taxes) for existing and new capacity in dollars
$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital for existing and new capacity (fraction)
$APRB_{a,t}$ = adjusted pipeline rate base for existing and new capacity in dollars
a = arc
t = forecast year

The return on rate base for existing and new capacity on an arc can be broken out into the three components:

$$PFEN_{a,t} = GPFESTR_a * PFER_{a,t} * APRB_{a,t} \quad (209)$$

$$CMEN_{a,t} = GCMESTR_a * CMER_{a,t} * APRB_{a,t} \quad (210)$$

$$LTDN_{a,t} = GLTDSTR_a * LTDR_{a,t} * APRB_{a,t} \quad (211)$$

where,

$PFEN_{a,t}$	=	total return on preferred stock for existing and new capacity (dollars)
$GPFESTR_a$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$PFER_{a,t}$	=	coupon rate for preferred stock for existing and new capacity (fraction)
$APRB_{a,t}$	=	adjusted rate base for existing and new capacity (dollars)
$CMEN_{a,t}$	=	total return on common stock equity for existing and new capacity (dollars)
$GCMESTR_a$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$CMER_{a,t}$	=	common equity rate of return for existing and new capacity (fraction)
$LTDN_{a,t}$	=	total return on long-term debt for existing and new capacity (dollars)
$GLTDSTR_a$	=	historical average capital structure ratio for long term debt for existing and new capacity (fraction), held constant over the forecast period
$LTDR_{a,t}$	=	long-term debt rate for existing and new capacity (fraction)
a	=	arc
t	=	forecast year

Next, annual depreciation, depletion, and amortization $DDA_{a,t}$ for a network arc in year t is calculated as the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with the arc. $DDA_{a,t}$ is defined earlier in equation 187.

Next, total taxes consist of Federal income taxes, State income taxes, deferred income taxes, and other taxes. Federal income taxes and State income taxes are calculated using average tax rates. The equation for total taxes is as follows:

$$TOTAX_{a,t} = FSIT_{a,t} + DIT_{a,t} + OTTAX_{a,t} \quad (212)$$

$$FSIT_{a,t} = FIT_{a,t} + SIT_{a,t} \quad (213)$$

where,

$TOTAX_{a,t}$	=	total Federal and State income tax liability for existing and new capacity (dollars)
$FSIT_{a,t}$	=	Federal and State income tax for existing and new capacity (dollars)
$FIT_{a,t}$	=	Federal income tax for existing and new capacity (dollars)

$SIT_{a,t}$ = State income tax for existing and new capacity (dollars)
$DIT_{a,t}$ = deferred income taxes for existing and new capacity (dollars)
$OTTAX_{a,t}$ = all other Federal, State, or local taxes for existing and new capacity (dollars)
a = arc
t = forecast year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the Federal tax rate. The after-tax profit is determined as follows:

$$ATP_{a,t} = APRB_{a,t} * (PFER_{a,t} * GPFESTR_a + CMER_{a,t} * GCMESTR_a) \tag{214}$$

where,

$ATP_{a,t}$ = after-tax profit for existing and new capacity (dollars)
$APRB_{a,t}$ = adjusted pipeline rate base for existing and new capacity (dollars)
$PFER_{a,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)
$GPFESTR_a$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$CMER_{a,t}$ = common equity rate of return for existing and new capacity (fraction)
$GCMESTR_a$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
a = arc
t = forecast year

and the Federal income taxes are:

$$FIT_{a,t} = (FRATE * ATP_{a,t} / 1. - FRATE) \tag{215}$$

where,

$FIT_{a,t}$ = Federal income tax for existing and new capacity (dollars)
FRATE = Federal income tax rate (fraction, Appendix E)
$ATP_{a,t}$ = after-tax profit for existing and new capacity (dollars)
a = arc
t = forecast year

State income taxes are computed by multiplying the sum of taxable profit and the associated Federal income tax by a weighted-average State tax rate associated with each pipeline company. The weighted-average State tax rate is based on peak service volumes in each State served by the pipeline company. State income taxes are computed as follows:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{216}$$

where,

$SIT_{a,t}$ = State income tax for existing and new capacity (dollars)
SRATE = average State income tax rate (fraction, Appendix E)
$FIT_{a,t}$ = Federal income tax for existing and new capacity (dollars)
$ATP_{a,t}$ = after-tax profits for existing and new capacity (dollars)
a = arc
t = forecast year

Deferred income taxes for existing and new capacity at the arc level are the differences in the accumulated deferred income taxes between year t and year t-1.

$$DIT_{a,t} = ADIT_{a,t} - ADIT_{a,t-1} \tag{217}$$

where,

$DIT_{a,t}$ = deferred income taxes for existing and new capacity (dollars)
$ADIT_{a,t}$ = accumulated deferred income taxes for existing and new capacity (dollars)
a = arc
t = forecast year

Other taxes consist of a combination of ad valorem taxes (which grow with company revenue), property taxes (which grow in proportion to gross plant), and all other taxes (assumed constant in real terms). Other taxes in year t are determined as the previous year's other taxes adjusted for inflation and capacity expansion.

$$OTTAX_{a,t} = OTTAX_{a,t-1} * EXPFAC_{a,t} * (MC\_PCWGDP_t / MC\_PCWGDP_{t-1}) \tag{218}$$

where,

$OTTAX_{a,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes for existing and new capacity (dollars)
$EXPFAC_{a,t}$ = capacity expansion factor (see below)
MC_PCWGDPt = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

The capacity expansion factor is expressed as follows:

$$EXPFAC_{a,t} = PTCURPCAP_{a,t} / PTCURPCAP_{a,t-1} \tag{219}$$

where,

$EXPFAC_{a,t}$ = capacity expansion factor (growth in capacity)
$PTCURPCAP_{a,t}$ = current pipeline capacity (Bcf) for existing and new capacity
a = arc
t = forecast year

Last, the total operating and maintenance costs for existing and new capacity by arc ($R\_TOM_{a,t}$) are determined using a log-linear form, given the economies of scale inherent in gas transmission. The estimated equation used for R_TOM (Appendix F, Table F3) is determined as a function of gross plant in service, $GPIS_a$, a level of accumulated depreciation relative to gross plant in service, $DEPSHR_a$, and a time trend, TECHYEAR, that proxies the state of technology, as defined below:

$$R\_TOM_{a,t} = TOM\_K * e^{(\beta_{0,a} * (1-\rho) + G2 + G3 + G4 + G5 + G6 - \rho * (G7 + G8 + G4 + G9))} \qquad (220)$$

where,

$R\_TOM_{a,t}$	=	total operating and maintenance cost for existing and new capacity (2005 real dollars)
TOM_K	=	correction factor estimated in stage 2 of the regression equation estimation process (Appendix F, Table F3)
$\beta_{0,a}$	=	TOM_C, constant term estimated by arc (Appendix F, Table F3.6, $\beta_{0,a} = B\_ARC_{xx\_yy}$)
G_2	=	$\beta_1 * \log(GPIS_{a,t-1})$
G_3	=	$\beta_2 * DEPSHR_{a,t-1}$
G_4	=	$\beta_3 * 2006.0$
G_5	=	$\beta_4 * (TECHYEAR-2006.0)$
G_6	=	$\rho * \log(R\_TOM_{a,t-1})$
G_7	=	$\beta_1 * \log(GPIS_{a,t-2})$
G_8	=	$\beta_2 * DEPSHR_{a,t-2}$
G_9	=	$\beta_4 * (TECHYEAR - 1.0- 2006.0)$
log	=	natural logarithm operator
ρ	=	estimated autocorrelation coefficient (Appendix F, Table F3.6 -- TOM_RHO)
β_1	=	TOM_GPIS_1, estimated coefficient on the change in gross plant in service (Appendix F, Table F3.6)
β_2	=	TOM_DEPSHR, estimated coefficient for the accumulated depreciation of the plant relative to the GPIS (Appendix F, Table F3.6)
β_3	=	TOM_BYEAR, estimated coefficient for the time trend variable TECHYEAR (Appendix F, Table F3.6)
β_4	=	TOM_BYEAR_EIA = TOM_BYEAR, estimated future rate of decline in R_TOM due to technology improvements and efficiency gains. EIA assumes that this coefficient is the same as the coefficient for the time trend variable TECHYEAR (Appendix F, Table F3.6)
$DEPSHR_{a,t}$	=	level of the accumulated depreciation of the plant relative to the gross plant in service for existing and new capacity at the beginning of year t. This variable is a proxy for the age of the capital stock.
$GPIS_{a,t}$	=	capital cost of plant in service for existing and new capacity in dollars (not deflated)
TECHYEAR	=	MODYEAR (time trend in 4 digit Julian units, the minimum value of this variable in the sample being 1997, otherwise TECHYEAR=0 if less than 1997)
a	=	arc
t	=	forecast year

For consistency the total operating and maintenance costs are converted to nominal dollars:

$$TOM_{a,t} = R\_TOM_{a,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{2000}} \tag{221}$$

where,

$TOM_{a,t}$ = total operating and maintenance costs for existing and new capacity (nominal dollars)
$R\_TOM_{a,t}$ = total operating and maintenance costs for existing and new capacity (2005 real dollars)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

Once all four components ($TRRB_{a,t}$, $DDA_{a,t}$, $TOTAX_{a,t}$, $TOM_{a,t}$) of the cost-of-service $TCOST_{a,t}$ of equation 207 are computed by arc in year t, each of them will be disaggregated into fixed and variable costs which in turn will be disaggregated further into reservation and usage costs using the allocation factors for a straight fixed variable (SFV) rate design summarized in **Table 6-6**.[89] Note that the return on rate base ($TRRB_{a,t}$) has three components ($PFEN_{a,t}$, $CMEN_{a,t}$, and $LTDN_{a,t}$ [equations 209, 210, and 211]).

Disaggregation of Cost-of-Service Components into Fixed and Variable Costs

Let $Item_{i,a,t}$ be a cost-of-service component (i=cost component index, a=arc, and t=forecast year). Using the first group of rate design allocation factors ξi (**Table 6-6**), all the components of cost-of-service computed in the above section can be split into fixed and variable costs, and then summed over the cost categories to determine fixed and variable costs-of-service as follows:

$$FC_{a,t} = \sum_i (\xi_i * Item_{i,a,t}) \tag{222}$$

$$VC_{a,t} = \sum_i [(1.0 - \xi_i) * Item_{i,a,t}] \tag{223}$$

$$TCOS_{a,t} = FC_{a,t} + VC_{a,t} \tag{224}$$

where,

$TCOS_{a,t}$ = total cost-of-service for existing and new capacity (dollars)
$FC_{a,t}$ = fixed cost for existing and new capacity (dollars)
$VC_{a,t}$ = variable cost for existing and new capacity (dollars)
$Item_{i,a,t}$ = cost-of-service component index at the arc level
ξ_i = first group of allocation factors (ratios) to disaggregate the cost-of-service components into fixed and variable costs

[89] The allocation factors of SFV rate design are given in percent in this table for illustration purposes. They are converted into ratios immediately after they are read in from the input file by dividing by 100.

Table 6-6. Percentage Allocation Factors for a Straight Fixed Variable (SFV) Rate Design

Cost-of-service Items (percentage) [$Item_{i,a,t}$, i=cost component index, a=arc, t=year]	**Break up cost-of-service items into fixed and variable costs**		**Break up fixed cost items into reservation and usage costs**		**Break up variable cost items into reservation and usage costs**	
$Item_{i,a,t}$	**$FC_{i,a,t}$**	**$VC_{i,a,t}$**	**$RFC_{i,a,t}$**	**$UFC_{i,a,t}$**	**$RVC_{i,a,t}$**	**$UVC_{i,a,t}$**
Cost Allocation Factors	ξ_i	$100 - \xi_i$	λ_i	$100 - \lambda_i$	μ_i	$100-\mu_i$
After-tax Operating Income						
Return on Preferred Stocks	100	0	100	0	0	100
Return on Common Stocks	100	0	100	0	0	100
Return on Long-Term Debt	100	0	100	0	0	100
Normal Operating Expenses						
Depreciation	100	0	100	0	0	100
Income Taxes	100	0	100	0	0	100
Deferred Income Taxes	100	0	100	0	0	100
Other Taxes	100	0	100	0	0	100
Total O&M	60	40	100	0	0	100

ξ_i = first group of allocation factors (ratios) to disaggregate the cost-of-service components into fixed and variable costs
i = subscript to designate a cost-of-service component (i=1 for PFEN, i=2 for CMEN, i=3 for LTDN, i=4 for DDA, i=5 for FSIT, i=6 for DIT, i=7 for OTTAX, and i=8 for TOM)
a = arc
t = forecast year

Disaggregation of Fixed and Variable Costs into Reservation and Usage Costs

Each type of cost-of-service component (fixed or variable) in the above equations can be further disaggregated into reservation and usage costs using the second and third groups of rate design allocation factors λi and μi (**Table 6-6**), as follows:

$$RFC_{a,t} = \sum_i (\lambda_i * \xi_i * Item_{i,a,t}) \tag{225}$$

$$UFC_{a,t} = \sum_i [(1.0 - \lambda_i) * \xi_i * Item_{i,a,t}] \tag{226}$$

$$RVC_{a,t} = \sum_i [\mu_i * (1.0 - \xi_i) * Item_{i,a,t}] \tag{227}$$

$$UVC_{a,t} = \sum_i [(1.0 - \mu_i) * (1.0 - \xi_i) * Item_{i,a,t}] \qquad (228)$$

$$TCOS_{a,t} = RFC_{a,t} + UFC_{a,t} + RVC_{a,t} + UVC_{a,t} \qquad (229)$$

where,

$TCOS_{a,t}$	=	total cost-of-service for existing and new capacity (dollars)
$RFC_{a,t}$	=	fixed reservation cost for existing and new capacity (dollars)
$UFC_{a,t}$	=	fixed usage cost for existing and new capacity (dollars)
$RVC_{a,t}$	=	variable reservation cost for existing and new capacity (dollars)
$UVC_{a,t}$	=	variable usage cost for existing and new capacity (dollars)
$Item_{i,a,t}$	=	cost-of-service component index at the arc level
ξ_i	=	first group of allocation factors to disaggregate cost-of-service components into fixed and variable costs
λ_i	=	second group of allocation factors to disaggregate fixed costs into reservation and usage costs
μ_i	=	third group of allocation factors to disaggregate variable costs into reservation and usage costs
i	=	subscript to designate a cost-of-service component (i=1 for PFEN, i=2 for CMEN, i=3 for LTDN, i=4 for DDA, i=5 for FSIT, i=6 for DIT, i=7 for OTTAX, and i=8 for TOM)
a	=	arc
t	=	forecast year

The summation of fixed and variable reservation costs (RFC and RVC) yields the total reservation cost (RCOST). This can be disaggregated further into peak and off-peak reservation costs, which are used to develop variable tariffs for peak and off-peak time periods. The summation of fixed and variable usage costs (UFC and UVC), which yields the total usage cost (UCOST), is used to compute the annual average fixed usage fees. Both types of rates are developed in the next section. The equations for the reservation and usage costs can be expressed as follows:

$$RCOST_{a,t} = (RFC_{a,t} + RVC_{a,t}) \qquad (230)$$

$$UCOST_{a,t} = (UFC_{a,t} + UVC_{a,t}) \qquad (231)$$

where,

$RCOST_{a,t}$	=	reservation cost for existing and new capacity (dollars)
$UCOST_{a,t}$	=	annual usage cost for existing and new capacity (dollars)
$RFC_{a,t}$	=	fixed reservation cost for existing and new capacity (dollars)
$UFC_{a,t}$	=	fixed usage cost for existing and new capacity (dollars)
$RVC_{a,t}$	=	variable reservation cost for existing and new capacity (dollars)
$UVC_{a,t}$	=	variable usage cost for existing and new capacity (dollars)
a	=	arc
t	=	forecast period

As **Table 6-6** indicates, all the fixed costs are included in the reservation costs and all the variable costs are included in the usage costs.

Computation of Rates for Forecast Years

The reservation and usage costs-of-service RCOST and UCOST determined above are used separately to develop two types of rates at the arc level: variable tariffs and annual fixed usage fees. The determination of both rates is described below.

Variable Tariff Curves

Variable tariffs are proportional to reservation charges and are broken up into peak and off-peak time periods. Variable tariffs are derived directly from variable tariff curves which are developed based on reservation costs, utilization rates, annual flows, and other curve parameters.

In the PTS code, these variable curves are defined by a FUNCTION (NGPIPE_VARTAR) which is called by the ITS to compute the variable tariffs for peak and off-peak by arc and by forecast year. In this pipeline function, the tariff curves are segmented such that tariffs associated with *current capacity* and *capacity expansion* are represented by separate but similar equations. A uniform functional form is used to define these tariff curves for both the *current capacity* and *capacity expansion segments* of the tariff curves. It is defined as a function of a base point [price and quantity (PNOD, QNOD)] using different *process-specific* parameters, peak or off-peak flow, and a price elasticity. This functional form is presented below:

current capacity segment:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA\_PIPE} \tag{232}$$

capacity expansion segment:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA2\_PIPE} \tag{233}$$

such that,

for peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR\_YR}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{234}$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \tag{235}$$

for off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{236}$$

$$QNOD_{a,t} = PT\,NETFLOW_{a,t} \tag{237}$$

where,

$NGPIPE\_VARTAR_{a,t}$	=	function to define pipeline tariffs (87$/Mcf)
$PNOD_{a,t}$	=	base point, price (87$/Mcf)
$QNOD_{a,t}$	=	base point, quantity (Bcf)
$Q_{a,t}$	=	flow along pipeline arc (Bcf)
ALPHA_PIPE	=	price elasticity for pipeline tariff curve for current capacity (Appendix E)
ALPHA2_PIPE	=	price elasticity for pipeline tariff curve for capacity expansion segment (Appendix E)
$RCOST_{a,t}$	=	reservation cost-of-service (million dollars)
$PTNETFLOW_{a,t}$	=	natural gas network flow (throughput, Bcf)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	forecast year

Annual Fixed Usage Fees

The annual fixed usage fees (volumetric charges) are derived directly from the usage costs, peak and off-peak utilization rates, and annual arc capacity. These fees are computed as the average fees over each forecast year, as follows:

$$FIXTAR_{a,t} = UCOST_{a,t} / [(PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_t] \tag{238}$$

where,

$FIXTAR_{a,t}$	=	annual fixed usage fees for existing and new capacity (87$/Mcf)
$UCOST_{a,t}$	=	annual usage cost for existing and new capacity (million dollars)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$	=	peak pipeline utilization (fraction)
$PTCURPCAP_{a,t}$	=	current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$	=	off-peak pipeline utilization (fraction)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	forecast year

As can be seen from the allocation factors in **Table 6-6**, usage costs (UCOST) are less than 10 percent of reservation costs (RCOST). Therefore, annual fixed usage fees which are proportional to usage costs are expected to be less than 10 percent of the variable tariffs. In general, these fixed fees are within the range of 5 percent of the variable tariffs which are charged to firm customers.

Canadian Fixed and Variable Tariffs

Fixed and variables tariffs along Canadian import arcs are defined using input data. Fixed tariffs are obtained directly from the data (Appendix E, $ARC\_FIXTAR_{n,a,t}$), while variables tariffs are calculated in the FUNCTION subroutine (NGPIPE_VARTAR) and are based on pipeline utilization and a maximum expected tariff, CNMAXTAR. If the pipeline utilization along a Canadian arc for any time period (peak or off-peak) is less than 50 percent, then the pipeline tariff is set to a low level (70 percent of CNMAXTAR). If the Canadian pipeline utilization is between 50 and 90 percent, then the pipeline tariff is set to a level between 70 and 80 percent of CNMAXTAR. The sliding scale is determined using the corresponding utilization factor, as follows:

$$NGPIPE\_VARTAR_{a,t} = CNMAXTAR - [CNMAXTAR * (1.0 - 0.9) * 2.0] - [CNMAXTAR * (0.9 - CANUTIL_{a,t}) * 0.25] \tag{239}$$

If the Canadian pipeline utilization is greater than 90 percent, then the pipeline tariff is set to between 80 and 100 percent of CNMAXTAR. This is accomplished again using Canadian pipeline utilization, as follows:

$$NGPIPE\_VARTAR_{a,t} = CNMAXTAR - [CNMAXTAR * (1.0 - CANUTIL_{a,t}) * 2.0] \tag{240}$$

where,

$$CANUTIL_{a,t} = \frac{Q_{a,t}}{QNOD_{a,t}} \tag{241}$$

for peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * PKSHR\_YR * PTPKUTZ_{a,t} \tag{242}$$

for off-peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} \tag{243}$$

and,

$NGPIPE\_VARTAR_{a,t}$	=	function to define pipeline tariffs (87$/Mcf)
CNMAXTAR	=	maximum effective tariff (87$/Mcf, ARC_VARTAR, Appendix E)

$CANUTIL_{a,t}$ = pipeline utilization (fraction)
$QNOD_{a,t}$ = base point, quantity (Bcf)
$Q_{a,t}$ = flow along pipeline arc (Bcf)
$PKSHR\_YR$ = portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$ = peak pipeline utilization (fraction)
$PTCURPCAP_{a,t}$ = current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$ = off-peak pipeline utilization (fraction)
a = arc
t = forecast year

For the eastern and western Canadian storage regions, the "variable" tariff is set to zero and only the assumed "fixed" tariff (Appendix E, ARC_FIXTAR) is applied.

Storage Tariff Routine Methodology

Background

This section describes the methodology used to assign a storage tariff for each of the 12 NGTDM regions. All variables and equations presented below are used for the forecast time period (1999-2030). If the time period t is less than 1999, the associated variables are set to the initial values read in from the input file (Foster's storage financial database[90] by region and year, 1990-1998).

This section starts with the presentation of the natural gas storage cost-of-service equation by region. The equation sums four components to be forecast: after-tax[91] total return on rate base (operating income); total taxes; depreciation, depletion, and amortization; and total operating and maintenance expenses. Once these four components are computed, the regional storage cost of service is projected and, with the associated effective storage capacity provided by the ITS, a storage tariff curve can be established (as described at the end of this section).

Cost-of-Service by Storage Region

The cost-of-service (or revenue requirement) for existing and new storage capacity in an NGTDM region can be written as follows:

$$STCOS_{r,t} = STBTOI_{r,t} + STDDA_{r,t} + STTOTAX_{r,t} + STTOM_{r,t} \quad (244)$$

where,

$STCOS_{r,t}$ = total cost-of-service or revenue requirement for existing and new capacity (dollars)

[90] Natural Gas Storage Financial Data, compiled by Foster Associates, Inc., Bethesda, Maryland for EIA under purchase order #01-99EI36663 in December of 1999. This data set includes financial information on 33 major storage companies. The primary source of the data is FERC Form 2 (or Form 2A for the smaller pipelines). These data can be purchased from Foster Associates.

[91] 'After-tax' in this section refers to 'after taxes have been taken out.'

$STBTOI_{r,t}$ = total return on rate base for existing and new capacity (after-tax operating income) (dollars)
$STDDA_{r,t}$ = depreciation, depletion, and amortization for existing and new capacity (dollars)
$STTOTAX_{r,t}$ = total Federal and State income tax liability for existing and new capacity (dollars)
$STTOM_{r,t}$ = total operating and maintenance expenses for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

The storage cost-of-service by region is first computed in nominal dollars and subsequently converted to 1987$ for use in the computation of a base for regional storage tariff, PNOD (87$/Mcf). PNOD is used in the development of a regional storage tariff curve. An approach is developed to project the storage cost-of-service in nominal dollars by NGTDM region in year t and is provided in **Table 6-7**.

Table 6-7. Approach to Projection of Storage Cost-of-Service

Projection Component	**Approach**
1. Capital-Related Costs	
a. Total return in rate base	Direct calculation from projected rate base and rates of return
b. Federal/State income taxes	Accounting algorithms based on tax rates
c. Deferred income taxes	Difference in the accumulated deferred income taxes between years t and t-1
2. Depreciation, Depletion, and Amortization	Estimated equation and accounting algorithm
3. Total Operating and Maintenance Expenses	Estimated equation

Computation of total return on rate base (after-tax operating income), STBTOIr,t

The total return on rate base for existing and new capacity is computed from the projected weighted cost of capital and estimated rate base, as follows:

$$STBTOI_{r,t} = STWAROR_{r,t} * STAPRB_{r,t} \tag{245}$$

where,

$STBTOI_{r,t}$ = total return on rate base (after-tax operating income) for existing and new capacity in dollars
$STWAROR_{r,t}$ = weighted-average after-tax rate of return on capital for existing and new capacity (fraction)
$STAPRB_{r,t}$ = adjusted storage rate base for existing and new capacity in dollars
r = NGTDM region
t = forecast year

The return on rate base for existing and new storage capacity in an NGTDM region can be broken out into three components as shown below.

$$STPFEN_{r,t} = STGPFESTR_r * STPFER_{r,t} * STAPRB_{r,t} \quad (246)$$

$$STCMEN_{r,t} = STGCMESTR_r * STCMER_{r,t} * STAPRB_{r,t} \quad (247)$$

$$STLTDN_{r,t} = STGLTDSTR_r * STLTDR_{r,t} * STAPRB_{r,t} \quad (248)$$

where,

$STPFEN_{r,t}$	=	total return on preferred stock for existing and new capacity (dollars)
$STPFER_{r,t}$	=	coupon rate for preferred stock for existing and new capacity (fraction)
$STGPFESTR_r$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STAPRB_{r,t}$	=	adjusted rate base for existing and new capacity (dollars)
$STCMEN_{r,t}$	=	total return on common stock equity for existing and new capacity (dollars)
$STGCMESTR_r$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$STCMER_{r,t}$	=	common equity rate of return for existing and new capacity (fraction)
$STLTDN_{r,t}$	=	total return on long-term debt for existing and new capacity (dollars)
$STGLTDSTR_r$	=	historical average capital structure ratio for long term debt for existing and new capacity (fraction), held constant over the forecast period
$STLTDR_{r,t}$	=	long-term debt rate for existing and new capacity (fraction)
r	=	NGTDM region
t	=	forecast year

Note that the total return on rate base is the sum of the above equations and can be expressed as:

$$STBTOI_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t} + STLTDN_{r,t}) \quad (249)$$

It can be seen from the above equations that the weighted average rate of return on capital for existing and new storage capacity, $STWAROR_{r,t}$, can be determined as follows:

$$STWAROR_{r,t} = STPFER_{r,t} * STGPFESTR_r + STCMER_{r,t} * STGCMESTR_r + STLTDR_{r,t} * STGLTDSTR_r \quad (250)$$

The historical average capital structure ratios $STGPFESTR_r$, $STGCMESTR_r$, and $STGLTDSTR_r$ in the above equation are computed as follows:

$$STGPFESTR_r = \frac{\sum_{t=1990}^{1998} STPFES_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \qquad (251)$$

$$STGCMESTR_r = \frac{\sum_{t=1990}^{1998} STCMES_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \qquad (252)$$

$$STGLTDSTR_r = \frac{\sum_{t=1990}^{1998} STLTDS_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \qquad (253)$$

where,

$STGPFESTR_r$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STGCMESTR_r$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$STGLTDSTR_r$	=	historical average capital structure ratio for long term debt for existing and new capacity (fraction), held constant over the forecast period
$STPFES_{r,t}$	=	value of preferred stock for existing capacity (dollars) [read in as D_PFES]
$STCMES_{r,t}$	=	value of common stock equity for existing capacity (dollars) [read in as D_CMES]
$STLTDS_{r,t}$	=	value of long-term debt for existing capacity (dollars) [read in as D_LTDS]
$STAPRB_{r,t}$	=	adjusted rate base for existing capacity (dollars) [read in as D_APRB]
r	=	NGTDM region
t	=	forecast year

In the STWAROR equation, the rate of return variables for preferred stock, common equity, and debt ($STPFER_{r,t}$, $STCMER_{r,t}$, and $STLTDR_{r,t}$) are related to forecast macroeconomic variables. These rates of return can be determined as a function of nominal AA utility bond index rate (provided by the Macroeconomic Module) and a regional historical average constant deviation as follows:

$$STPFER_{r,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_STPFER_r \qquad (254)$$

$$STCMER_{r,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_STCMER_r \tag{255}$$

$$STLTDR_{r,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_STLTDR_r \tag{256}$$

where,

$STPFER_{r,t}$	=	rate of return for preferred stock
$STCMER_{r,t}$	=	common equity rate of return
$STLTDR_{r,t}$	=	long-term debt rate
$MC\_RMPUAANS_t$	=	AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPUAA, percentage)
ADJ_STPFER_r	=	historical weighted average deviation constant (fraction) for preferred stock rate of return (1990-1998)
ADJ_STCMER_r	=	historical weighted average deviation constant (fraction) for common equity rate of return (1990-1998)
ADJ_STLTDR_r	=	historical weighted average deviation constant (fraction) for long term debt rate (1990-1998)
r	=	NGTDM region
t	=	forecast year

The historical weighted average deviation constants by NGTDM region are computed as follows:

$$ADJ\_STLTDR_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STLTDN_{r,t}}{STLTDS_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \tag{257}$$

$$ADJ\_STPFER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STPFEN_{r,t}}{STPFES_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \tag{258}$$

$$ADJ\_STCMER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STCMEN_{r,t}}{STCMES_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \tag{259}$$

where,

ADJ_STLTDR_r	=	historical weighted average deviation constant (fraction) for long term debt rate
ADJ_STCMER_r	=	historical weighted average deviation constant (fraction) for common equity rate of return
ADJ_STPFER_r	=	historical weighted average deviation constant (fraction) for preferred stock rate of return

$STPFEN_{r,t}$ = total return on preferred stock for existing capacity (dollars) [read in as D_PFEN]
$STCMEN_{r,t}$ = total return on common stock equity for existing capacity (dollars) [read in as D_CMEN]
$STLTDN_{r,t}$ = total return on long-term debt for existing capacity (dollars) [read in as D_LTDN]
$STPFES_{r,t}$ = value of preferred stock for existing capacity (dollars) [read in as D_PFES]
$STCMES_{r}$ = value of common stock equity for existing capacity (dollars) [read in as D_CMES]
$STLTDS_{r}$ = value of long-term debt for existing capacity (dollars) [read in as D_LTDS]
$MC\_RMPUAANS_{t}$ = AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPPUAA, percentage)
$STGPIS_{r,t}$ = original capital cost of plant in service (dollars) [read in as D_GPIS]
r = NGTDM region
t = forecast year

Computation of adjusted rate base, $STAPRB_{r,t}$[92]

The adjusted rate base for existing and new storage facilities in an NGTDM region has three components and can be written as follows:

$$STAPRB_{r,t} = STNPIS_{r,t} + STCWC_{r,t} - STADIT_{r,t} \tag{260}$$

where,

$STAPRB_{r,t}$ = adjusted storage rate base for existing and new capacity (dollars)
$STNPIS_{r,t}$ = net plant in service for existing and new capacity (dollars)
$STCWC_{r,t}$ = total cash working capital for existing and new capacity (dollars)
$STADIT_{r,t}$ = accumulated deferred income taxes for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

The net plant in service is the level of gross plant in service minus the accumulated depreciation, depletion, and amortization. It is given by the following equation:

$$STNPIS_{r,t} = STGPIS_{r,t} - STADDA_{r,t-1} \tag{261}$$

[92]In this section, any variable ending with "_E" will signify that the variable is for the existing storage capacity as of the end of 1998, and any variable ending with "_N" will mean that the variable is for the new storage capacity added from 1999 to 2025.

where,

$STNPIS_{r,t}$ = net plant in service for existing and new capacity (dollars)
$STGPIS_{r,t}$ = gross plant in service for existing and new capacity (dollars)
$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

The gross and net plant-in-service variables can be written as the sum of their respective existing and new gross and net plants in service as follows:

$$STGPIS_{r,t} = STGPIS\_E_{r,t} + STGPIS\_N_{r,t} \tag{262}$$

$$STNPIS_{r,t} = STNPIS\_E_{r,t} + STNPIS\_N_{r,t} \tag{263}$$

where,

$STGPIS_{r,t}$ = gross plant in service for existing and new capacity (dollars)
$STNPIS_{r,t}$ = net plant in service for existing and new capacity (dollars)
$STGPIS\_E_{r,t}$ = gross plant in service for existing capacity (dollars)
$STGPIS\_N_{r,t}$ = gross plant in service for new capacity (dollars)
$STNPIS\_E_{r,t}$ = net plant in service for existing capacity (dollars)
$STNPIS\_N_{r,t}$ = net plant in service for new capacity (dollars)
r = NGTDM region
t = forecast year

For the same reason as above, the accumulated depreciation, depletion, and amortization for t-1 can be split into its existing and new accumulated depreciation:

$$STADDA_{r,t-1} = STADDA\_E_{r,t-1} + STADDA\_N_{r,t-1} \tag{264}$$

where,

$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity (dollars)
$STADDA\_E_{r,t}$ = accumulated depreciation, depletion, and amortization for existing capacity (dollars)
$STADDA\_N_{r,t}$ = accumulated depreciation, depletion, and amortization for new capacity (dollars)
r = NGTDM region
t = forecast year

The accumulated depreciation for the current year t is expressed as last year's accumulated depreciation plus this year's depreciation. For the separate existing and new storage capacity, their accumulated depreciation, depletion, and amortization can be expressed separately as follows:

$$STADDA\_E_{r,t} = STADDA\_E_{r,t-1} + STDDA\_E_{r,t} \tag{265}$$

$$STADDA\_N_{r,t} = STADDA\_N_{r,t-1} + STDDA\_N_{r,t} \tag{266}$$

where,

$STADDA\_E_{r,t}$ = accumulated depreciation, depletion, and amortization for existing capacity (dollars)
$STADDA\_N_{r,t}$ = accumulated depreciation, depletion, and amortization for new capacity (dollars)
$STDDA\_E_{r,t}$ = depreciation, depletion, and amortization for existing capacity (dollars)
$STDDA\_N_{r,t}$ = depreciation, depletion, and amortization for new capacity (dollars)
r = NGTDM region
t = forecast year

Total accumulated depreciation, depletion, and amortization for the combined existing and new capacity by storage region in year t is determined as the sum of previous year's accumulated depreciation, depletion, and amortization and current year's depreciation, depletion, and amortization for that total capacity.

$$STADDA_{r,t} = STADDA_{r,t-1} + STDDA_{r,t} \tag{267}$$

where,

$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity in dollars
$STDDA_{r,t}$ = annual depreciation, depletion, and amortization for existing and new capacity in dollars
r = NGTDM region
t = forecast year

Computation of annual depreciation, depletion, and amortization, $STDDA_{r,t}$

Annual depreciation, depletion, and amortization for a storage region in year t is the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with that region.

$$STDDA_{r,t} = STDDA\_E_{r,t} + STDDA\_N_{r,t} \tag{268}$$

where,

$STDDA_{r,t}$ = annual depreciation, depletion, and amortization for existing and new capacity in dollars
$STDDA\_E_{r,t}$ = depreciation, depletion, and amortization costs for existing capacity in dollars
$STDDA\_N_{r,t}$ = depreciation, depletion, and amortization costs for new capacity in dollars
r = NGTDM region
t = forecast year

A regression equation is used to determine the annual depreciation, depletion, and amortization for existing capacity associated with an NGTDM region, while an accounting algorithm is used for new storage capacity. For existing capacity, this depreciation expense by NGTDM region is forecast as follows:

$$STDDA\_E_{r,t} = STDDA\_CREG_r + STDDA\_NPIS * STNPIS\_E_{r,t-1} + STDDA\_NEWCAP * STNEWCAP_{r,t} \qquad (269)$$

where,

$STDDA\_E_{r,t}$	=	annual depreciation, depletion, and amortization costs for existing capacity in dollars
$STDDA\_CREG_r$	=	constant term estimated by region (Appendix F, Table F3)
STDDA_NPIS	=	estimated coefficient for net plant in service for existing capacity (Appendix F, Table F3)
STDDA_NEWCAP	=	estimated coefficient for the change in gross plant in service for existing capacity (Appendix F, Table F3)
$STNPIS\_E_{r,t}$	=	net plant in service for existing capacity (dollars)
$STNEWCAP_{r,t}$	=	change in gross plant in service for existing capacity (dollars)
r	=	NGTDM region
t	=	forecast year

The accounting algorithm used to define the annual depreciation, depletion, and amortization for new capacity assumes straight-line depreciation over a 30-year life, as follows:

$$STDDA\_N_{r,t} = STGPIS\_N_{r,t} / 30 \qquad (270)$$

where,

$STDDA\_N_{r,t}$	=	annual depreciation, depletion, and amortization for new capacity in dollars
$STGPIS\_N_{r,t}$	=	gross plant in service for new capacity in dollars
30	=	30 years of plant life
r	=	NGTDM region
t	=	forecast year

In the above equation, the capital cost of new plant in service ($STGPIS\_N_{r,t}$) in year t is computed as the accumulated new capacity expansion expenditures from 1999 to year t and is determined by the following equation:

$$STGPIS\_N_{r,t} = \sum_{s=1999}^{t} STNCAE_{r,s} \qquad (271)$$

where,

$STGPIS\_N_{r,t}$	=	gross plant in service for new capacity expansion in dollars
$STNCAE_{r,s}$	=	new capacity expansion expenditures occurring in year s after 1998 (in dollars)
s	=	the year new expansion occurred
r	=	NGTDM region
t	=	forecast year

The new capacity expansion expenditures allowed in the rate base within a forecast year are derived for each NGTDM region from the amount of incremental capacity additions determined by the ITS:

$$STNCAE_{r,t} = STCCOST_{r,t} * STCAPADD_{r,t} * 1{,}000{,}000. \qquad (272)$$

where,

$STNCAE_{r,t}$	=	total capital cost to expand capacity for an NGTDM region (dollars)
$STCCOST_{r,t}$	=	capital cost per unit of natural gas storage expansion (dollars per Mcf)
$STCAPADD_{r,t}$	=	storage capacity additions as determined in the ITS (Bcf/yr)
r	=	NGTDM region
t	=	forecast year

The capital cost per unit of natural gas storage expansion in an NGTDM region ($STCCOST_{r,t}$) is computed as its 1998 unit capital cost times a function of a capacity expansion factor relative to the 1998 storage capacity. This expansion factor represents a relative change in capacity since 1998. Whenever the ITS forecasts storage capacity additions in year t in an NGTDM region, the increased capacity is computed for that region from 1998 and the unit capital cost is computed. Hence, the capital cost to expand capacity in an NGTDM region can be estimated from any amount of capacity additions in year t provided by the ITS and the associated unit capital cost. This capital cost represents the investment cost for generic storage companies associated with that region. The unit capital cost ($STCCOST_{r,t}$) is computed by the following equations:

$$STCCOST_{r,t} = STCCOST\_CREG_r * e^{(BETAREG_r * STEXPFAC98_r)} * (1.0 + STCSTFAC) \qquad (273)$$

where,

$STCCOST_{r,t}$	=	capital cost per unit of natural gas storage expansion (dollars per Mcf)
$STCCOST\_CREG_r$	=	1998 capital cost per unit of natural gas storage expansion (1998 dollars per Mcf)
$BETAREG_r$	=	expansion factor parameter (set to STCCOST_BETAREG, Appendix E)
$STEXPFAC98_r$	=	relative change in storage capacity since 1998
STCSTFAC	=	factor to set a particular storage region's expansion cost, based on an average [Appendix E]
r	=	NGTDM region
t	=	forecast year

The relative change in storage capacity is computed as follows:

$$STEXPFAC98_r = \frac{PTCURPSTR_{r,t}}{PTCURPSTR_{r,1998}} - 1.0 \qquad (274)$$

where,

$PTCURPSTR_{r,t}$ = current storage capacity (Bcf)
$PTCURPSTR_{r,1998}$ = 1998 storage capacity (Bcf)
r = NGTDM region
t = forecast year

Computation of total cash working capital, $STCWC_{r,t}$

The total cash working capital represents the level of working capital at the beginning of year t deflated using the chain weighted GDP price index with 1996 as a base year. This cash working capital variable is expressed as a non-linear function of total gas storage capacity (base gas capacity plus working gas capacity) as follows:

$$R\_STCWC_{r,t} = e^{(STCWC\_CREG_r * (1-\rho))} * DSTTCAP_{r,t-1}^{STCWC\_TOTCAP} * R\_STCWC_{r,t-1}^{\rho} * DSTTCAP_{r,t-2}^{-\rho * STCWC\_TOTCAP} \qquad (275)$$

where,

$R\_STCWC_{r,t}$ = total cash working capital at the beginning of year t for existing and new capacity (1996 real dollars)
$STCWC\_CREG_r$ = constant term, estimated by region (Appendix F, Table F3)
ρ = autocorrelation coefficient from estimation (Appendix F, Table F3 — STCWC_RHO)
$DSTTCAP_{r,t}$ = total gas storage capacity (Bcf)
STCWC_TOTCAP = estimated DSTTCAP coefficient (Appendix F, Table F3)
r = NGTDM region
t = forecast year

This total cash working capital in 1996 real dollars is converted to nominal dollars to be consistent with the convention used in this submodule.

$$STCWC_{r,t} = R\_STCWC_{r,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{1996}} \qquad (276)$$

where,

$STCWC_{r,t}$ = total cash working capital at the beginning of year t for existing and new capacity (nominal dollars)
$R\_STCWC_{r,t}$ = total cash working capital at the beginning of year t for existing and new capacity (1996 real dollars)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
r = NGTDM region
t = forecast year

Computation of accumulated deferred income taxes, $STADIT_{r,t}$

The level of accumulated deferred income taxes for the combined existing and new capacity in year t in the adjusted rate base equation is a stock (not a flow) and depends on income tax regulations in effect, differences in tax, and book depreciation. It can be expressed as a linear function of its own lagged variable and the change in the level of gross plant in service between time t and t-1. The forecasting equation can be written as follows:

$$STADIT_{r,t} = STADIT\_C + (STADIT\_ADIT * STADIT_{r,t-1}) + (STADIT\_NEWCAP * NEWCAP_{r,t}) \tag{277}$$

where,

$STADIT_{r,t}$	=	accumulated deferred income taxes in dollars
STADIT_C	=	constant term from estimation (Appendix F, Table F3)
STADIT_ADIT	=	estimated coefficient for lagged accumulated deferred income taxes (Appendix F, Table F3)
STADIT_NEWCAP	=	estimated coefficient for change in gross plant in service (Appendix F, Table F3)
$NEWCAP_{r,t}$	=	change in gross plant in service for the combined existing and new capacity between years t and t-1 (in dollars)
r	=	NGTDM region
t	=	forecast year

Computation of Total Taxes, $STTOTAX_{r,t}$

Total taxes consist of Federal income taxes, State income taxes, deferred income taxes, and other taxes. Federal income taxes and State income taxes are calculated using average tax rates. The equation for total taxes is as follows:

$$STTOTAX_{r,t} = STFSIT_{r,t} + STDIT_{r,t} + STOTTAX_{r,t} \tag{278}$$

$$STFSIT_{r,t} = STFIT_{r,t} + STSIT_{r,t} \tag{279}$$

where,

$STTOTAX_{r,t}$	=	total Federal and State income tax liability for existing and new capacity (dollars)
$STFSIT_{r,t}$	=	Federal and State income tax for existing and new capacity (dollars)
$STFIT_{r,t}$	=	Federal income tax for existing and new capacity (dollars)
$STSIT_{r,t}$	=	State income tax for existing and new capacity (dollars)
$STDIT_{r,t}$	=	deferred income taxes for existing and new capacity (dollars)
STOTTAX	=	all other taxes assessed by Federal, State, or local governments for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the Federal tax rate. The after-tax profit is the operating income excluding the total long-term debt, which is determined as follows:

$$STATP_{r,t} = STAPRB_{r,t} * (STPFER_{r,t} * STGPFESTR_r + STCMER_{r,t} * STGCMESTR_r) \quad (280)$$

$$STATP_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t}) \quad (281)$$

where,

$STATP_{r,t}$ = after-tax profit for existing and new capacity (dollars)
$STAPRB_{r,t}$ = adjusted pipeline rate base for existing and new capacity (dollars)
$STPFER_{r,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)
$STGPFESTR_r$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STCMER_{r,t}$ = common equity rate of return for existing and new capacity (fraction)
$STGCMESTR_r$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$STPFEN_{r,t}$ = total return on preferred stock for existing and new capacity (dollars)
$STCMEN_{r,t}$ = total return on common stock equity for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

and the Federal income taxes are

$$STFIT_{r,t} = (FRATE * STATP_{r,t}) / (1. - FRATE) \quad (282)$$

where,

$STFIT_{r,t}$ = Federal income tax for existing and new capacity (dollars)
FRATE = Federal income tax rate (fraction, Appendix E)
$STATP_{r,t}$ = after-tax profit for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

State income taxes are computed by multiplying the sum of taxable profit and the associated Federal income tax by a weighted-average State tax rate associated with each NGTDM region. State income taxes are computed as follows:

$$STSIT_{r,t} = SRATE * (STFIT_{r,t} + STATP_{r,t}) \quad (283)$$

where,

$STSIT_{r,t}$ = State income tax for existing and new capacity (dollars)
SRATE = average State income tax rate (fraction, Appendix E)
$STFIT_{r,t}$ = Federal income tax for existing and new capacity (dollars)
$STATP_{r,t}$ = after-tax profits for existing and new capacity (dollars)

r = NGTDM region
t = forecast year

Deferred income taxes for existing and new capacity at the arc level are the differences in the accumulated deferred income taxes between year t and year t-1.

$$STDIT_{r,t} = STADIT_{r,t} - STADIT_{r,t-1} \tag{284}$$

where,

$STDIT_{r,t}$ = deferred income taxes for existing and new capacity (dollars)
$STADIT_{r,t}$ = accumulated deferred income taxes for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

Other taxes consist of a combination of ad valorem taxes (which grow with company revenue), property taxes (which grow in proportion to gross plant), and all other taxes (assumed constant in real terms). Other taxes in year t are determined as the previous year's other taxes adjusted for inflation.

$$STOTTAX_{r,t} = STOTTAX_{r,t-1} * (MC\_PCWGDP_t / MC\_PCWGDP_{t-1}) \tag{285}$$

where,

$STOTTAX_{r,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes for existing and new capacity (dollars) [read in as D_OTTAXr,t , t=1990-1998]
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
r = NGTDM region
t = forecast year

Computation of total operating and maintenance expenses, $STTOM_{r,t}$

The total operating and maintenance costs (including administrative costs) for existing and new capacity in an NGTDM region are determined in 1996 real dollars using a log-linear form with correction for serial correlation. The estimated equation is determined as a function of working gas storage capacity for region r at the beginning of period t. In developing the estimations, the impact of regulatory change and the differences between producing and consuming regions were analyzed.[93] Because their impacts were not supported by the data, they were not accounted for in the estimations. The final estimating equation is:

$$R\_STTOM_{r,t} = e^{(STTOM\_C*(1-\rho))} * DSTWCAP_{r,t-1}^{STTOM\_WORKCAP} * R\_STTOM_{r,t-1}^{\rho} * DSTWCAP_{r,t-2}^{-\rho*STTOM\_WORKCAP} \tag{286}$$

[93]The gas storage industry changed substantially when in 1994 FERC Order 636 required jurisdictional pipeline companies to operate their storage facilities on an open-access basis. The primary customers and use of storage in producing regions are significantly different from consuming regions.

where,

$R\_STTOM_{r,t}$ = total operating and maintenance cost for existing and new capacity (1996 real dollars)
$STTOM\_C$ = constant term from estimation (Appendix F, Table F3)
ρ = autocorrelation coefficient from estimation (Appendix F, Table F3 -- STTOM_RHO)
$DSTWCAP_{r,t}$ = level of gas working capacity for region r during year t
$STTOM\_WORKCAP$ = estimated DSTWCAP coefficient (Appendix F, Table F3)
r = NGTDM region
t = forecast year

Finally, the total operating and maintenance costs are converted to nominal dollars to be consistent with the convention used in this submodule.

$$STTOM_{r,t} = R\_STTOM_{r,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{1996}} \qquad (287)$$

where,

$STTOM_{r,t}$ = total operating and maintenance costs for existing and new capacity (nominal dollars)
$R\_STTOM_{r,t}$ = total operating and maintenance costs for existing and new capacity (1996 real dollars)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
r = NGTDM region
t = forecast year

Computation of Storage Tariff

The regional storage tariff depends on the storage cost of service, current working gas capacity, utilization rate, natural gas storage activity, and other factors. The functional form is similar to the pipeline tariff curve, in that it will be built from a regional base point [price and quantity (PNOD,QNOD)]. The base regional storage tariff ($PNOD_{r,t}$) is determined as a function of the cost of service ($STCOS_{r,t}$ (equation 244)) and other factors discussed below. $QNOD_{r,t}$ is set to an effective working gas storage capacity by region, which is defined as a regional working gas capacity times its utilization rate. Hence, once the storage cost of service is computed by region, the base point can be established. Minor adjustments to the storage tariff routine will be necessary in order to obtain the desired results.

In the model, the storage cost of service used represents only a portion of the total storage cost of service, the revenue collected from the customers for withdrawing during the peak period the quantity of natural gas stored during the off-peak period. This portion is defined as a user-set percentage (STRATIO, Appendix E) representing the portion (ratio) of revenue requirement obtained by storage companies for storing gas during the off-peak and withdrawing it for the customers during the peak period. This would include charges for injections, withdrawals, and reserving capacity.

The cost of service $STCOS_{r,t}$ is computed using the Foster storage financial database which represents only the storage facilities owned by the interstate natural gas pipelines in the U.S. which have filed a Form 2 financial report with the FERC. Therefore, an adjustment to this cost of service to account for all the storage companies by region is needed. For example, at the national level, the Foster database shows the underground storage working gas capacity at 2.3 Tcf in 1998 and the EIA storage gas capacity data show much higher working gas capacity at 3.8 Tcf. Thus, the average adjustment factor to obtain the "actual" cost of service across all regions in the U.S. is 165 percent. This adjustment factor, $STCAP\_ADJ_{r,t}$, varies from region to region.

To complete the design of the storage tariff computation, two more factors need to be incorporated: the regional storage tariff curve adjustment factor and the regional efficiency factor for storage operations, which makes the storage tariff more competitive in the long-run.

Hence, the regional average storage tariff charged to customers for moving natural gas stored during the off-peak period and withdrawn during the peak period can be computed as follows:

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC\_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP\_ADJ_{r,t} * ADJ\_STR * (1.0 - STR\_EFF/100.)^t \quad (288)$$

where,

$$STCAP\_ADJ_{r,t} = \frac{PTCURPSTR_{r,t}}{FS\_PTCURPSTR_{r,t}} \quad (289)$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \quad (290)$$

and,

$PNOD_{r,t}$	=	base point, price (87$/Mcf)
$STCOS_{r,t}$	=	storage cost of service for existing and new capacity (dollars)
$QNOD_{r,t}$	=	base point, quantity (Bcf)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
$STRATIO_{r,t}$	=	portion of revenue requirement obtained by moving gas from the off-peak to the peak period (fraction, Appendix E)
$STCAP\_ADJ_{r,t}$	=	adjustment factor for the cost of service to total U.S. (ratio)
ADJ_STR	=	storage tariff curve adjustment factor (fraction, Appendix E)
STR_EFF	=	efficiency factor (percent) for storage operations (Appendix E)
$PTSTUTZ_{r,t}$	=	storage utilization (fraction)
$PTCURPSTR_{r,t}$	=	current storage capacity (Bcf)

$FS\_PTCURPSTR_{r,t}$ = Foster storage working gas capacity (Bcf) [read in as D_WCAP]
r = NGTDM region
t = forecast year

Finally, the storage tariff curve by region can be expressed as a function of a base point [price and quantity (PNOD, QNOD)], storage flow, and a price elasticity, as follows:

current capacity segment:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA\_STR} \tag{291}$$

capacity expansion segment:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA2\_STR} \tag{292}$$

where,

$X1NGSTR\_VARTAR_{r,t}$ = function to define storage tariffs (87$/Mcf)
$PNOD_{r,t}$ = base point, price (87$/Mcf)
$QNOD_{r,t}$ = base point, quantity (Bcf)
$Q_{r,t}$ = regional storage flow (Bcf)
ALPHA_STR = price elasticity for storage tariff curve for current capacity (Appendix E)
ALPHA2_STR = price elasticity for storage tariff curve for capacity expansion segment (Appendix E)
r = NGTDM region
t = forecast year

Alaska and MacKenzie Delta Pipeline Tariff Routine

A single routine (FUNCTION NGFRPIPE_TAR) estimates the potential per-unit pipeline tariff for moving natural gas from either the North Slope of Alaska or the MacKenzie Delta to the market hub in Alberta, Canada for the years beyond the specified in-service date. The tariff estimates are based on a simple cost-of-service rate base methodology, given the infrastructure's initial capital cost at the beginning of the construction period (FR_CAPITL0 in billion dollars, Appendix E), the assumed number of years for the project to be completed (FRPCNSYR, Appendix E), the associated discount rate for the project (FR_DISCRT, Appendix E), the initial capacity (a function of delivered volume FR_PVOL, Appendix E), and the number of years over which the final cost of capitalization is assumed completely amortized (INVEST_YR=15). The input values vary depending on whether the tariff being calculated is associated with a pipeline for Alaska or for MacKenzie Delta gas. The cost of service consists of the following four components: depreciation, depletion, and amortization; after-tax operating income (known as the return on rate base); total operating and maintenance expenses; and total income taxes. The computation of each of the four components in nominal dollars per Mcf is described below:

Depreciation, depletion, and amortization, FR_DDA_t

The depreciation is computed as the final cost of capitalization at the start of operations divided by the amortization period. The depreciation equation is provided below:

$$FR\_DDA_t = FR\_CAPITL1 / INVEST\_YR \tag{293}$$

where,

FR_DDA_t	=	depreciation, depletion, and amortization costs (thousand nominal dollars)
FR_CAPITL1	=	final cost of capitalization at the start of operations (thousand nominal dollars)
INVEST_YR	=	investment period allowing recovery (parameter, INVEST_YR=15)
t	=	forecast year

The structure of the final cost of capitalization, FR_CAPITL1, is computed as follows:

$$\begin{aligned} FR\_CAPITL1 = {} & FR\_CAPIT0 / FR\_PCNSYR * \\ & [(1+r) + (1+r)^2 + ... + (1+r)^{FR\_PCNSYR}] \end{aligned} \tag{294}$$

where,

FR_CAPITL1	=	final cost of capitalization at the start of operations (thousand nominal dollars)
FR_CAPITL0	=	initial capitalization (thousand FR_CAPYR dollars), where FR_CAPYR is the year dollars associated with this assumed capital cost (Appendix E)
FR_PCNSYR	=	number of construction years (Appendix E)
r	=	cost of debt, fraction, which is equal to the nominal 10-year Treasury bill (MC_RMTCM10Y or TNOTE, in percent) plus a debt premium in percent (debt premium set to FR_DISCRT, Appendix E)

The net plant in service is tied to the depreciation by the following formulas:

$$\begin{aligned} FR\_NPIS_t &= FR\_GPIS_t - FR\_ADDA_t \\ FR\_ADDA_t &= FR\_ADDA_{t-1} + FR\_DDA_t \end{aligned} \tag{295}$$

where,

FR_GPIS_t	=	original capital cost of plant in service (gross plant in service) in thousand nominal dollars, set to FR_CAPITL1.
FR_NPIS_t	=	net plant in service (thousand nominal dollars)
FR_ADDA_t	=	accumulated depreciation, depletion, and amortization in thousand nominal dollars
t	=	forecast year

After-tax operating income (return on rate base), FR_TRRB_t

This after-tax operating income also known as the return on rate base is computed as the net plant in service times an annual rate of return (FR_ROR, Appendix E). The net plant in service, FR_NPIS_t, gets updated each year and is equal to the initial gross plant in service minus accumulated depreciation. Net plant in service becomes the adjusted rate base when other capital related costs such as materials and supplies, cash working capital, and accumulated deferred income taxes are equal to zero.

The return on rate base is computed as follows:

$$FR\_TRRB_t = WACC_t * FR\_NPIS_t \tag{296}$$

where,

$$\begin{aligned} WACC_t = {} & FR\_DEBTRATIO * COST\_OF\_DEBT_t + \\ & (1.0 - FR\_DEBTRATIO) * COST\_OF\_EQUITY_t \end{aligned} \tag{297}$$

and

$$COST\_OF\_DEBT_t = (TNOTE_t + FR\_DISCRT) / 100. \tag{298}$$

$$COST\_OF\_EQUITY_t = (TNOTE_t / 100. \tag{299}$$

where,

FR_TRRB_t	=	after-tax operating income or return on rate base (thousand nominal dollars)
$WACC_t$	=	weighted average cost of capital (fraction), nominal
FR_NPIS_t	=	net plant in service (thousand nominal dollars)
$COST\_OF\_DEBT_t$	=	cost of debt (fraction)
$COST\_OF\_EQUITY_t$	=	cost of equity (fraction)
$TNOTE_t$	=	nominal 10-year Treasury bill rate, ($MC\_RMTCM10Y_t$, percent) provided by the Macroeconomic Activity Module
FR_DISCRT	=	user-set debt premium, percent (Appendix E)
FR_ROR_PREM	=	user-set risk premium, percent (Appendix E)
t	=	forecast year

Total taxes, FR_TAXES_t

Total taxes consist of Federal and State income taxes and taxes other than income taxes. Each tax category is computed based on a percentage times net profit. These percentages are drawn from the Foster financial report's 28 major interstate natural gas pipeline companies. The percentage for income taxes (FR_TXR) is computed as the average over five years (1992-1996) of tax to net operating income ratio from the Foster report. Likewise, the percentage (FR_OTXR) for taxes other than income taxes is computed as the average over five years (1992-1996) of taxes other than income taxes to net operating income ratio from the same report. Total taxes are computed as follows:

$$FR\_TAXES_t = (FR\_TXR + FR\_OTXR) * FR\_NETPFT_t \tag{300}$$

where,

FR_TAXES_t = total taxes (thousand nominal dollars)
FR_NETPFT_t = net profit (thousand nominal dollars)
FR_TXR = 5-year average Lower 48 pipeline income tax rate, as a proxy (Appendix E)
FR_OTXR = 5-year average Lower 48 pipeline other income tax rate, as a proxy (Appendix E)
t = forecast year

Net profit, FR_NETPFT, is computed as the return on rate base (FR_TRRB_t) minus the long-term debt (FR_LTD_t), which is calculated as the return on rate base times long-term debt rate times the debt to capital structure ratio. The net profit and long-term debt equations are provided below:

$$FR\_NETPFT_t = (FR\_TRRB_t - FR\_LTD_t) \quad (301)$$

$$FR\_LTD_t = FR\_DEBTRATIO * (TNOTE_t + FR\_DISCRT) / 100.0 * FR\_NPIS_t \quad (302)$$

where,

FR_LTD_t = long-term debt (thousand nominal dollars)
FR_NPIS_t = net plant in service (thousand nominal dollars)
FR_DEBTRATIO = 5-year average Lower 48 pipeline debt structure ratio (Appendix E)
FR_NETPFT_t = net profit (thousand nominal dollars)
FR_TRRB_t = return on rate base (thousand nominal dollars)
$TNOTE_t$ = nominal 10-year Treasury bill, (MC_RMTCM10Y, percent) provided by the Macroeconomic Activity Module
FR_DISCRT = user-set debt premium, percent (Appendix E)
t = forecast year

In the above equations, the long-term debt rate is assumed equal to the 10-year Treasury bill plus a debt premium, which represents a risk premium generally charged by financial institutions. When 10-year Treasury bill rates are needed for years beyond the last forecast year (LASTYR), the variable $TNOTE_t$ becomes the average over a number of years (FR_ESTNYR, Appendix E) of the 10-year Treasury bill rates for the last forecast years.

Cost of Service, FR_COS_t

The cost of service is the sum of four cost-of-service components computed above, as follows:

$$FR\_COS_t = (FR\_TRRB_t + FR\_DDA_t + FR\_TAXES_t + FR\_TOM_{FR\_CAPYR} * (MC\_PCWGDP_t / MC\_PCWGDP_{FR\_CAPYR}) * FR\_PVOL * 1.1484 * 1000.0) \quad (303)$$

where,

FR_COS_t	=	cost of service (thousand nominal dollars)
FR_TRRB_t	=	return on rate base (thousand nominal dollars)
FR_DDA_t	=	depreciation (thousand nominal dollars)
FR_TAXES_t	=	total taxes (thousand nominal dollars)
FR_TOMFR_CAPYR	=	total operating and maintenance expenses (in nominal dollars per Mcf, set constant in real terms) (Appendix E)
MC_PCWGDP_t	=	GDP price deflator (from Macroeconomic Activity Module)
FR_PVOL	=	maximum volume delivered to Alberta in dry terms (Bcf/year)
1.1484	=	factor to convert delivered dry volume to wet gas volume entering the pipeline as a proxy for the pipeline capacity
t	=	forecast year

Hence, the annual pipeline tariff in nominal dollars is computed by dividing the above cost of service by total pipeline capacity, as follows:

$$COS_t = FR\_COS_t / (FR\_PVOL * 1.1484 * 1000.0) \quad (304)$$

where,

COS_t	=	per-unit cost of service or annual pipeline tariff (nominal dollars/Mcf)
t	=	forecast year

To convert this nominal tariff to real 1987$/Mcf, the GDP implicit price deflator variable provided by the Macroeconomic Activity Module is needed. The real tariff equation is written as follows:

$$COSR_t = COS_t / MC\_PCWGDP_t \quad (305)$$

where,

$COSR_t$	=	annual real pipeline tariff (1987 dollars/Mcf)
MC_PCWGDP_t	=	GDP price deflator (from Macroeconomic Activity Module)
t	=	forecast year

Last, the annual average tariff is computed as the average over a number of years (FR_AVGTARYR, Appendix E) of the first successive annual cost of services.

7. Model Assumptions, Inputs, and Outputs

This last chapter summarizes the model and data assumptions used by the Natural Gas Transmission and Distribution Module (NGTDM) and lists the primary data inputs to and outputs from the NGTDM.

Assumptions

This section presents a brief summary of the assumptions used within the NGTDM. Generally, there are two types of data assumptions that affect the NGTDM solution values. The first type can be derived based on historical data (past events), and the second type is based on experience and/or events that are likely to occur (expert or analyst judgment). A discussion of the rationale behind assumed values based on analyst judgment is beyond the scope of this report. Most of the FORTRAN variables related to model input assumptions, both those derived from known sources and those derived through analyst judgment, are identified in this chapter, with background information and actual values referenced in Appendix E.

The assumptions summarized in this section are mentioned in Chapters 2 through 6. They are used in NGTDM equations as starting values, coefficients, factors, shares, bounds, or user specified parameters. Six general categories of data assumptions have been defined: classification of market services, demand, transmission and distribution service pricing, pipeline tariffs and associated regulation, pipeline capacity and utilization, and supply (including imports). These assumptions, along with their variable names, are summarized below.

Market Service Classification

Nonelectric sector natural gas customers are classified as either core or noncore customers, with core customers defined as the type of customer that is expected to generally transport their gas under firm (or near firm) transportation agreements and noncore customers to generally transport their gas under non-firm (interruptible or short-term capacity release) transportation agreements. The residential, commercial, and transportation (natural gas vehicles) sectors are assumed to be core customers. The transportation sector is further subdivided into fleet and personal vehicle customers. Industrial and electric generator end users fall into both categories, with industrial boilers and refineries assumed to be noncore and all other industrial users assumed to be core, and gas steam units or gas combined cycle units assumed to be core and all other electric generators assumed to be noncore. Currently the core/noncore distinction for electric generators is not being used in the model.

Demand

The peak period is defined *(using PKOPMON)* to run from December through March, with the off-peak period filling up the remainder of the year.

The Alaskan natural gas consumption levels for residential and commercial sectors are primarily defined as a function of the number of customers *(AK_RN, AK_CM, Tables F1, F2)*, which in turn are set based on an exogenous projection of the population in Alaska *(AK_POP)*. Alaskan gas consumption is disaggregated into North and South Alaska in order to separately compute the natural gas production forecasts in these regions. Lease, plant, and pipeline fuel related to an Alaska pipeline or a gas-to-liquids facility are set at an assumed percentage of their associated gas volumes *(AK_PCTPLT, AK_PCTPIP, AK_PCTLSE)*. The remaining lease and plant fuel is assumed to be consumed in the North and set based on historical trends. The amount of gas consumed by other sectors in North Alaska is small enough to assume as zero and to allow for the setting of South Alaska volumes equal to the totals for the State. Industrial consumption in South Alaska is set to the exogenously specified sum of the level of gas consumed at the Agrium fertilizer plant and at the liquefied natural gas plant *(AK_QIND_S)*. Pipeline fuel in the South is set as a percentage *(AK_PCTPIP)* of consumption and exports. Production in the south is set to total consumption levels in the region. In the north production equals the flow along an Alaska pipeline to Alberta, any gas needed to support the production of gas-to-liquids, associated lease, plant, and pipeline fuel for these two applications, and the other calculated lease and plant fuel. The forecast for reporting discrepancy in Alaska *(AK_DISCR)* is set to an average historical value. To compute natural gas prices by end-use sector for Alaska, fixed markups derived from historical data *(AK_RM, AK_CM, AK_IN, AK_EM)* are added to the average Alaskan natural gas wellhead price over the North and South regions. The wellhead price is set using a simple estimated equation *(AK_F)*. Historically based percentages and markups are held constant throughout the forecast period.

The shares *(NG_CENSHR)* for disaggregating nonelectric Census Division demands to NGTDM regions are held constant throughout the forecast period and are based on average historical relationships *(SQRS, SQCM, SQIN, SQTR)*. Similarly, the shares for disaggregating end-use consumption levels to peak and off-peak periods are held constant throughout the forecast, and are directly *(United States -- PKSHR_DMD, PKSHR_UDMD_F, PKSHR_UDMD_I)* or partially *(Canada -- PKSHR_CDMD)* historically based. Canadian consumption levels are set exogenously *(CN_DMD)* based on another published forecast, and adjusted if the associated world oil price changes. Consumption, base level production, and domestically consumed LNG imports into Mexico are set exogenously *(PEMEX_GFAC, IND_GFAC, ELE_GFAC, RC_GFAC, PRD_GFAC, MEXLNG)*. After the base level production is adjusted based on the average U.S. wellhead price, exports to Mexico are set to balance supply and consumption. Historically based shares *(PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, PKSHR_ILNG)* are applied to projected/historical values for natural gas exports and imports *(SEXP, SIMP, CANEXP, Q23TO3, FLO_THRU_IN,OGQNGEXP)*. These historical based shares are generated from monthly historical data *(QRS, QCM, QIN, QEU, MON_QEXP, MON_QIMP)*.

Lease and plant fuel consumption in each NGTDM region is computed as an historically derived percentage *(using SQLP)* of dry gas production *(PCTLP)* in each NGTDM/OGSM region. These percentages are held constant throughout the forecast period. Pipeline fuel use is derived using historically *(SQPF)* based factors *(PFUEL_FAC)* relating pipeline fuel use to the quantity of natural gas exiting a regional node. Values for the most recent historical year are derived from monthly-published figures *(QLP_LHIS, NQPF_TOT)*.

Pricing of Distribution Services

End-use prices for residential, commercial, industrial, transportation, and electric generation customers are derived by adding markups to the regional hub price of natural gas. Each regional end-use markup consists of an intraregional tariff *(INTRAREG_TAR)*, an intrastate tariff *(INTRAST_TAR)*, a distribution tariff *(endogenously defined)*, and a city gate benchmark factor [endogenously defined based on historical seasonal city gate prices (HCGPR)]. Historical distributor tariffs are derived for all sectors as the difference between historical city gate and end-use prices *(SPRS, SPCM, SPIN, SPEU, SPTR, PRS, PCM PIN, PEU)*.[94] Historical industrial end-use prices are derived in the module using an econometrically estimated equation (Table F5).[95] The residential, commercial, industrial, and electric generator distributor tariffs are also based on econometrically estimated equations (Tables F4, F6, F7, and F8). The distributor tariff for the personal (PV) and fleet vehicle (FV) components of the transportation sector are set using historical data, a decline rate *(TRN_DECL)*, state and federal taxes *(STAX, FTAX)*, and assumed dispensing costs/charges *(RETAIL_COST)*, and for personal vehicles at retail stations, a capital cost recovery markup *(CNG_RETAIL_MARKUP)*.

Prices for exports (and fixed volume imports) are based on historical differences between border prices *(SPIM, SPEX, MON_PIMP, MON_PEXP)* and their closest market hub price (as determined in the module when executed during the historical years).

Pipeline and Storage Tariffs and Regulation

Peak and off-peak transportation rates for interstate pipeline services (both between NGTDM regions and within a region) are calculated assuming that the costs of new pipeline capacity will be rolled into the existing rate base. Peak and off-peak market transmission service rates are based on a cost-of-service/rate-of-return calculation for current pipeline capacity times an assumed utilization rate *(PKUTZ, OPUTZ)*. To reflect recent regulatory changes related to alternative ratemaking and capacity release developments, these tariffs are discounted (based on an assumed price elasticity) as pipeline utilization rates decline.

In the computation of natural gas pipeline transportation and storage rates, the Pipeline Tariff Submodule uses a set of data assumptions based on historical data or expert judgment. These include the following:

[94] All historical prices are converted from nominal to real 1987 dollars using a price deflator *(GDP_B87)*.

[95] Traditionally industrial prices have been derived by collecting sales data from local distribution companies. More recently, industrial customers have not relied on LDCs to purchase their gas. As a result, annually published industrial natural gas prices only represent a rather small portion of the total population. In the module, these published prices are adjusted using an econometrically estimated equation based on EIA's survey of manufacturers to derive a more representative set of industrial prices.

- Factors *(AFX, AFR, AVR)* to allocate each company's line item costs into the fixed and variable cost components of the reservation and usage fees
- Capacity reservation shares used to allocate cost of service components to portions of the pipeline network
- Average pipeline capital cost (2005 dollars) per unit of expanded capacity by arc *(AVGCOST)* used to derive total capital costs to expand pipeline capacity
- Storage capacity expansion cost parameters *(STCCOST_CREG, STCCOST_BETAREG, STCSTFAC)* used to derive total capital costs to expand regional storage capacity
- Input coefficients *(ALPHA_PIPE, ALPH2_PIPE, ALPHA_STR, ALPHA2_STR, ADJ_STR, STR_EFF)* for transportation and storage rates
- Pipeline tariff curve parameters by arc *(PKSHR_YR, PTPKUTZ, PTOPUTZ, ALPHA_PIPE, ALPHA2_PIPE)*
- Storage tariff curve parameters by region *(STRATIO, STCAP_ADJ, PTSTUTZ, ADJ_STR, STR_EFF, ALPHA_STR, ALPHA2_STR)*

In order to determine when a pipeline from either Alaska or the MacKenzie Delta to Alberta could be economic, the model estimates the tariff that would be charged on both pipelines should they be built, based on a number of assumed values. A simple cost-of-service/rate-of-return calculation is used, incorporating the following: initial capitalization *(FR_CAPITLO)*, return on debt *(FR_DISCRT)* and return on equity *(FR_ROR_PREM)* (both specified as a premium added to the 10-year Treasury bill rate), total debt as a fraction of total capital *(FR_DEBTRATIO)*, operation and maintenance expenses *(FR_TOM0)*, federal income tax rate *(FR_TXR)*, other tax rate *(FR_OTXR)*, levelized cost period *(FR_AVGTARYR)*, and depreciation period *(INVEST_YR)*. In order to establish the ultimate charge for the gas in the lower 48 States assumptions were made for the minimum wellhead price *(FR_PMINWPC)* including production, treatment, and fuel costs, as well as the average differential between Alberta and the lower 48 *(ALB_TO_L48)* and a risk premium *(FR_PRISK)* to reflect cost and market uncertainties. The market price in the lower 48 states must be maintained over a planning horizon *(FR_PPLNYR)* before construction would begin. Construction is assumed to take a set number of years *(FR_PCNSYR)* and result in a given initial capacity based on initial delivered volumes *(FR_PVOL)*. An additional expansion is assumed on the condition of an increase in the market price *(FR_PADDTAR, FR_PEXPFAC)*.

Pipeline and Storage Capacity and Utilization

Historical and planned interregional, intraregional, and Canadian pipeline capacities are assigned in the module for the historical years and the first few years *(NOBLDYR)* into the forecast *(ACTPCAP, PTACTPCAP, PLANPCAP, SPLANPCAP, PER_YROPEN, CNPER_YROPEN)*. The flow of natural gas along these pipeline corridors in the peak and off-peak periods of the historical years is set, starting with historical shares *(HPKSHR_FLOW)*, to be consistent with the annual flows *(HAFLOW, SAFLOW)* and other known seasonal network volumes (e.g., consumption, production).

A similar assignment is used for storage capacities *(PLANPCAP, ADDYR)*. The module only represents net storage withdrawals in the peak period and net storage injections in the off-peak period, which are known historically *(HNETWTH, HNETINJ, SNETWTH, NWTH_TOT, NINJ_TOT)*.

For the forecast years, the use of both pipeline and storage capacity in each seasonal period is limited by exogenously set maximum utilization rates *(PKUTZ, OPUTZ, SUTZ)*, although these are currently not active for pipelines. They were originally intended to reflect an expected variant in the load throughout a season. Adjustments are now being made within the module, during the flow sharing algorithm, to reflect the seasonal load variation.

The decision concerning the share of gas that will come from each incoming source into a region for the purpose of satisfying the regions consumption levels (and some of the consumption upstream) is based on the relative costs of the incoming sources and assumed parameters *(GAMMAFAC, MUFAC)*. During the process of deciding the flow of gas through the network, an iterative process is used that requires a set of assumed parameters for assessing and responding to nonconvergence *(PSUP_DELTA, QSUP_DELTA, QSUP_SMALL, QSUP_WT, MAXCYCLE)*.

Supply

The supply curves for domestic lower 48 nonassociated dry gas production and for conventional and tight gas production from the WCSB are based on an expected production level, the former of which is set in the OGSM. Expected production from the WCSB is set in the NGTDM using a series of three econometric equations for new successful wells drilled, quantity proved per well drilled, and expected quantity produced per current level proved, and is dependent on resource assumptions *(RESBASE, RESTECH)*. A set of parameters *(PARM_SUPCRV3, PARM_SUPCRV5, SUPCRV, PARM_SUPELAS)* defines the price change from a base or expected price as production deviates from this expected level. These supply curves are limited by minimum and maximum levels, calculated as a factor *(PARM_MINPR, MAXPRRFAC, MAXPRRCAN)* times the expected production levels. Domestic associated-dissolved gas production is provided by the Oil and Gas Supply Module. Eastern Canadian production from other than the WCSB is set exogenously *(CN_FIXSUP)*. Natural gas production in Canada from both coal beds and shale is based on assumed production withdrawal profiles from their perspective resource base totals *(ULTRES, ULTSHL)* at an assumed exogenously specified price path and is adjusted relative to how much the actual western Canadian price differs from the assumed. Production from the frontier areas in Canada (i.e., the MacKenzie Delta) is set based on the assumed size of the pipeline to transport the gas to Alberta, should the pipeline be built. Production from Alaska is a function of the consumption in Alaska and the potential capacity of a pipeline from Alaska to Alberta and/or a gas-to-liquids facility.

Imports from Mexico and Canada at each border crossing point are represented as follows: (1) Mexican imports are set exogenously *(EXP_FRMEX)* with the exception of LNG imported into Baja for U.S. markets; (2) Canadian imports are set endogenously (except for the imports into the East North Central region, *(Q23TO3)* and limited to Canadian pipeline capacities *(ACTPCAP, CNPER_YROPEN)*, which are set in the module, and expand largely in response to the introduction of Alaskan gas into the Alberta system. Total gas imports from Canada exclude the amount of gas that travels into the United States and then back into Canada *(FLO_THRU_IN)*.

Liquefied natural gas imports are represented with an east and west supply curves to North America generated based on output results from EIA's International Natural Gas Model and shared to representative regional terminals based on regasification capacity, last year's imports, and relative prices. Regasification capacity is set based on known facilities, either already constructed or highly likely to be *(LNGCAP)*.

The three supplemental production categories (synthetic production of natural gas from coal and liquids and other supplemental fuels) are represented as constant supplies within the Interstate Transmission Submodule, with the exception of any production from potential new coal-to-gas plants. Synthetic production from the existing coal plant is set exogenously *(SNGCOAL)*. Forecast values for the other two categories are held constant throughout the forecast and are set to historical values *(SNGLIQ, SUPPLM)* within the module. The algorithm for determining the potential construction of new coal-to-gas plants uses an extensive set of detailed cost figures to estimate the total investment and operating costs of a plant (including accounting for emissions costs, electricity credits, and lower costs over time due to learning) for use within a discounted cash flow calculation. If positive cash flow is estimated to occur the number of generic plants built is based on a Mansfield-Blackman market penetration algorithm. Throughout the forecast, the annual synthetic gas production levels are split into seasonal periods using an historically *(NSUPLM_TOT)* based share *(PKSHR_SUPLM)*.

The supply component uses an assortment of input values in defining historical production levels and prices (or revenues) by the regions and categories required by the module *(QOF_ALST, QOF_ALFD, QOF_LAST, QOF_LAFD, QOF_CA, ROF_CA, QOF_LA, ROF_LA, QOF_TX, ROF_TX, AL_ONSH, AL_OFST, AL_OFFD, LA_ONSH, LA_OFST, lA_OFFD , ADW, NAW, TGD, MISC_ST, MISC_GAS, MISC_OIL, SMKT_PRD, SDRY_PRD, HQSUP, HPSUP, WHP_LHIS, SPWH)*. A set of seasonal shares *(PKSHR_PROD)* have been defined based on historical values *(MONMKT_PRD)* to split production levels of supply sources that are nonvariant with price *(CN_FIXSUP and others)* into peak and off-peak categories.

Discrepancies that exist between historical supply and disposition level data are modeled at historical levels *(SBAL_ITM)* in the NGTDM and kept constant throughout the forecast years at average historical levels *(DISCR, CN_DISCR)*.

Model Inputs

The NGTDM inputs are grouped into six categories: mapping and control variables, annual historical values, monthly historical values, Alaskan and Canadian demand/supply variables, supply inputs, pipeline and storage financial and regulatory inputs, pipeline and storage capacity and utilization related inputs, end-use pricing inputs, and miscellaneous inputs. Short input data descriptions and identification of variable names that provide more detail (via Appendix E) on the sources and transformation of the input data are provided below.

Mapping and Control Variables

- Variables for mapping from States to regions *(SNUM_ID, SCH_ID, SCEN_DIV, SITM_REG, SNG_EM, SNG_OG, SIM_EX, MAP_PRDST)*
- Variables for mapping import/export borders to States and to nodes *(CAN_XMAPUS, CAN_XMAPCN, MEX_XMAP, CAN_XMAP)*
- Variables for handling and mapping arcs and nodes *(PROC_ORD,ARC_2NODE, NODE_2ARC, ARC_LOOP, SARC_2NODE, SNODE_2ARC, NODE_ANGTS, CAN_XMAPUS)*
- Variables for mapping supply regions *(NODE_SNGCOAL, MAPLNG_NG, OCSMAP, PMMMAP_NG, SUPSUB_NG, SUPSUB_OG)*
- Variables for mapping demand regions *(EMMSUB_NG, EMMSUB_EL, NGCENMAP)*

Annual Historical Values

- Offshore natural gas production and revenue data (QOF_ALST, QOF_ALFD, QOF_LAST, QOF_LAFD, QOF_CA, ROF_CA, QOF_LA, ROF_LA, QOF_TX, ROF_TX, QOF_AL, ROF_AL, QOF_MS, ROF_MS, QOF_GM, ROF_GM, PRICE_CA, PRICE_LA, PRICE_AL, PRICE_TX, GOF_LA, GOF_AL, GOF_TX, GOF_CA, AL_ONSH, AL_OFST, AL_OFFD, LA_ONSH, LA_OFST, LA_OFFD, AL_ONSH2, AL_OFST2, AL_ADJ)
- State-level supply prices *(SPIM, SPWH)*
- State/sub-state-level natural gas production and other supply/storage data *(ADW, NAW, TGD, TGW, MISC_ST, MISC_GAS, MISC_OIL, SMKT_PRD, SDRY_PRD, SIMP, SNET_WTH, SUPPLM)*
- State-level consumption levels *(SBAL_ITM, SEXP, SQPF, SQLP, SQRS, SQCM, SQIN, SQEU, SQTR)*
- State-level end-use prices *(SPEX, SPRS, SPCM, SPIN, SPEU, SPTR)*
- Miscellaneous *(GDP_B87, OGHHPRNG)*

Monthly Historical Values

- State-level natural gas production data *(MONMKT_PRD)*
- Import/export volumes and prices by source *(MON_QIMP, MON_PIMP, MON_QEXP, MON_PEXP, HQIMP)*
- Storage data *(NWTH_TOT, NINJ_TOT, HNETWTH, HNETINJ)*
- State-level consumption and prices *(CON & PRC -- QRS, QCM, QIN, QEU, PRS, PCM, PIN, PEU)*
- Electric power gas consumption and prices *(CON_ELCD, PRC_EPMCD, CON_EPMGR, PRC_EPMGR)*
- Miscellaneous monthly/seasonal data *(NQPF_TOT, NSUPLM_TOT, WHP_LHIS, QLP_LHIS, HCGPR)*

Alaskan, Canadian, & Mexican Demand/Supply Variables

- Alaskan lease, plant, and pipeline fuel parameters *(AK_PCTPLT, AK_PCTPIP, AK_PCTLSE)*
- Alaskan consumption parameters *(AK_QIND_S, AK_RN, AK_CM, AK_POP, AK_HDD, HI_RN)*
- Alaskan pricing parameters *(AK_RM, AK_CM, AK_IN, AK_EM)*
- Canadian production and end-use consumption *(CN_FIXSUP, CN_DMD, PKSHR_PROD, PKSHR_CDMD)*
- Exogenously specified Canadian import/export related volumes *(CANEXP, Q23TO3, FLO_THRU_IN)*
- Historical western Canadian production and wellhead prices *(HQSUP, HPSUP)*
- Unconventional western Canadian production parameters *(ULTRES, ULTSHL, RESBASE, PKIYR, LSTYR0, PERRES, RESTECH, TECHGRW)*
- Mexican production, LNG imports, and end-use consumption *(PEMEX_GFAC, IND_GFAC,ELE_GFAC,RC_GFAC, PRD_GFAC, MEXLNG)*

Supply Inputs

- Liquefied natural gas supply curves and pricing *(LNGCAP, PARM_LNGCRV3, PARM_LNGCRV5,PARM_LNGELAS, LNGPPT, LNGQPT, LNGMIN,PERQ, BETA,LNGTAR)*
- Supply curve parameters *(SUPCRV, PARM_MINPR, PARM_SUPCRV3, PARM_SUPCRV5, PARM_SUPELAS, MAXPRRFAC, MAXPRRNG, PARM_MINPR)*
- Synthetic natural gas projection *(SNGCOAL, SNGLIQ, NRCI_INV, NRCI_LABOR_NRCI_OPER,INFL_RT, FEDTAX_RT, STTAX_RT, INS_FAC, TAX_FAC, MAINT_FAC, OTH_FAC,BEQ_OPRAVG, BEQ_OPRHRSK, EMRP_OPRAVG, EMRP_OPRHRSK, EQUITY_OPRAVG, EQUITY_OPRHRSK, BEQ_BLDAVG, BEQ_BLDHRSK, EMRP_BLDAVG, EMRP_BLDHRSK, EQUITY_BLDAVG, EQUITY_BLDHRSK, BA_PREM, PCLADJ, CTG_CAPYR$, PRJSDECOM, CTG_BLDYRS, CTG_PRJLIFE, CTG_OSBLFAC, CTG_PCTENV, CTG_PCTCNTG, CTG_PCTLND, CTG_PCTSPECL, CTG_PCTWC, CTG_STAFF_LCFAC, CTG_OH_LCFAC, CTG_FSIYR, CTG_INCBLD, CTG_DCLCAPCST, CTG_DCLOPRCST, CTG_BASHHV, CTG_BASCOL, CTG_BCLTON, CTG_BASSIZ, CTG_BASCGS, CTG_BASCGSCO2, CTG_BASCGG, CTG_BASCGGCO2,CTG_NCL, CTG_NAM, CTG_CO2,LABORLOC, CTG_PUCAP, XBM_ISBL, XBM_LABOR, CTG_BLDX, CTG_IINDX, CTG_SINVST)*

Pipeline and Storage Financial and Regulatory Inputs

- Rate design specification *(AFX_PFEN, AFR_PFEN, AVR_PFEN, AFX_CMEN, AFR_CMEN, AVR_CMEN, AFX_LTDN, AFR_LTDN, AVR_LTDN, AFX_DDA, AFR_DDA, AVR_DDA, AFX_FSIT, AFR_FSIT, AVR_FSIT, AFX_DIT, AFR_DIT, AVR_DIT, AFX_OTTAX, AFR_OTTAX, AVR_OTTAX, AFX_TOM, AFR_TOM, AVR_TOM)*
- Pipeline rate base, cost, and volume parameters *(D_TOM, D_DDA, D_OTTAX, D_DIT, D_GPIS, D_ADDA, D_NPIS, D_CWC, D_ADIT, D_APRB, D_GPFES, D_GCMES, D_GLTDS, D_PFER, D_CMER, D_LTDR)*
- Storage rate base, cost, and volume parameters *(D_TOM, D_DDA, D_ADDA, D_OTTAX, D_FSIT, D_DIT, D_LTDN, D_PFEN, D_CMEN, D_GPIS, D_NPIS, D_CWC, D_ADIT, D_APRB, D_LTDS, D_PFES, D_CMES, D_TCAP, D_WCAP)*
- Pipeline and storage revenue requirement forecasting equation parameters *(Table F3)*
- Rate of return set for generic pipeline companies *(MC_RMPUAANS, ADJ_PFER, ADJ_CMER, ADJ_LTDR)*
- Rate of return set for existing and new storage capacity *(MC_RMPUAANS, ADJ_STPFER, ADJ_STCMER, ADJ_STLTDR)*
- Federal and State income tax rates *(FRATE, SRATE)*
- Depreciation schedule *(30 year life)*
- Pipeline capacity expansion cost parameter for capital cost equations *(AVGCOST)*
- Pipeline capacity replacement cost parameter *(PCNT_R)*
- Storage capacity expansion cost parameters for capital cost equations *(STCCOST_CREG, STCCOST_BETAREG, STCSTFAC)*
- Parameters for interstate pipeline transportation rates *(PKSHR_YR, PTPKUTZ, PTOPUTZ, ALPHA_PIPE, ALPHA2_PIPE)*
- Canadian pipeline and storage tariff parameters *(ARC_FIXTAR, ARC_VARTAR, CN_FIXSHR)*
- Parameters for storage rates *(STRATIO, STCAP_ADJ, PTSTUTZ, ADJ_STR, STR_EFF, ALPHA_STR, ALPHA2_STR)*
- Parameters for Alaska-to-Alberta and MacKenzie Delta-to-Alberta pipelines *(FR_CAPITL0, FR_CAPYR, FR_PCNSYR, FR_DISCRT, FR_PVOL, INVEST_YR,FR_ROR_PREM, FR_TOM0, FR_DEBTRATIO, FR_TXR, FR_OTXR, FR_ESTNYR, FR_AVGTARYR)*

Pipeline and Storage Capacity and Utilization Related Inputs

- Canadian natural gas pipeline capacity and planned capacity additions *(ACTPCAP, PTACTPCAP, PLANPCAP, CNPER_YROPEN)*
- Maximum peak and off-peak primary and secondary pipeline utilizations *(PKUTZ, OPUTZ, SUTZ, MAXUTZ, XBLD)*
- Interregional planned pipeline capacity additions along primary and secondary arcs (PLANPCAP, SPLANPCAP, PER_YROPEN)
- Maximum storage utilization (PKUTZ)
- Existing storage capacity and planned additions *(PLANPCAP, ADDYR)*
- Net storage withdrawals (peak) and injections (off-peak) in Canada *(HNETWTH, HNETINJ)*
- Historical flow data *(HPKSHR_FLOW, HAFLOW, SAFLOW)*
- Alaska-to-Alberta and MacKenzie Delta-to-Alberta pipeline *(FR_PMINYR, FR_PVOL, FR_PCNSYR, FR_PPLNYR, FR_PEXPFAC, FR_PADDTAR, FR_PMINWPR, FR_PRISK, FR_PDRPFAC, FR_PTREAT, FR_PFUEL)*

End-Use Pricing Inputs

- Residential, commercial, industrial, and electric generator distributor tariffs *(OPTIND, OPTCOM, OPTRES, OPTELP, OPTELO, RECS_ALIGN, NUM_REGSHR, HHDD)*
- Intrastate and intraregional tariffs *(INTRAST_TAR, INTRAREG_TAR)*
- Historical city gate prices *(HCGPR)*

- State and Federal taxes, costs to dispense, and other compressed natural gas pricing and infrastructure development parameters *(STAX, FTAX, RETAIL_COST, NSTAT, TRN_DECL, MAX_CNG_BUILD, CNG_HRZ, CNG_WACC, CNG_BUILDCOST)*

Miscellaneous

- Network processing control variables *(MAXCYCLE, NOBLDYR,ALPHAFAC, GAMMAFAC, PSUP_DELTA, QSUP_DELTA, QSUP_SMALL, QSUP_WT, PCT_FLO, SHR_OPT, PCTADJSHR)*
- Miscellaneous control variables *(PKOPMON, NGDBGRPT, SHR_OPT, NOBLDYR)*
- STEO input data *(STEOYRS, STQGPTR, STQLPIN, STOGWPRNG, STPNGRS, STPNGIN, STPNGCM, STPNGEL, STOGPRSUP, NNETWITH, STDISCR, STENDCON, STSCAL_CAN, STINPUT_SCAL, STSCAL_PFUEL, STSCAL_LPLT, STSCAL_WPR, STSCAL_DISCR, STSCAL_SUPLM, STSCAL_NETSTR, STSCAL_FPR, STSCAL_IPR, STPHAS_YR, STLNGIMP)*

Model Outputs

Once a set of solution values are determined within the NGTDM, those values required by other modules of NEMS are passed accordingly. In addition, the NGTDM module results are presented in a series of internal and external reports, as outlined below.

Outputs to NEMS Modules

The NGTDM passes its solution values to different NEMS modules as follows:

- Pipeline fuel consumption and lease and plant fuel consumption by Census Division (to NEMS PROPER and REPORTS)
- Natural gas wellhead prices by Oil and Gas Supply Module region (to NEMS REPORTS, Oil and Gas Supply Module, and Petroleum Market Module)
- Core and noncore natural gas prices by sector and Census Division (to NEMS PROPER and REPORTS, and NEMS demand modules)
- Fraction of retail fueling stations that sell compressed natural gas (to Transportation Sector Module)
- Dry natural gas production and supplemental gas supplies by Oil and Gas Supply Module region (NEMS REPORTS and Oil and Gas Supply Module)
- Peak/off-peak, core/ noncore natural gas prices to electric generators by NGTDM/Electricity Market Module region (to NEMS PROPER and REPORTS and Electricity Market Module)
- Coal consumed, electricity generated, and CO2 produced in the process of converting coal into pipeline quality synthetic gas in newly constructed plants (to Coal Market Module, Electricity Market Module, and NEMS PROPER)
- Dry natural gas production by PADD region (to Petroleum Market Module)
- Nonassociated dry natural gas production by NGTDM/Oil and Gas Supply Module region (to NEMS REPORTS and Oil and Gas Supply Module)
- Natural gas imports, exports, and associated prices by border crossing (to NEMS REPORTS)

Internal Reports

The NGTDM produces reports designed to assist in the analysis of NGTDM model results. These reports are controlled with a user-defined variable (NGDBGRPT), include the following information, and are written to the indicated output file:

- Primary peak and off-peak flows, shares, and maximum constraints going into each node (NGOBAL)
- Historical and forecast values historically based factors applied in the module (NGOBENCH)
- Intermediate results from the Distributor Tariff Submodule (NGODTM)
- Intermediate results from the Pipeline Tariff Submodule (NGOPTM)
- Convergence tracking and error message report (NGOERR)
- Aggregate/average historical values for most model elements (NGOHIST)
- Node and arc level prices and quantities along the network by cycle (NGOTREE)

External Reports

In addition to the reports described above, the NGTDM produces external reports to support recurring publications. These reports contain the following information:

- Natural gas end-use prices and consumption levels by end-use sector, type of service (core and noncore), and Census Division (and for the United States)
- Natural gas used to in a gas-to-liquids conversion process in Alaska
- Natural gas wellhead prices and production levels by NGTDM region (and the average for the lower 48 States), including a price for the Henry Hub
- Natural gas end-use and city gate prices and margins
- Natural gas import and export volumes and import prices by source or destination
- Pipeline fuel consumption by NGTDM region (and for the United States)
- Natural gas pipeline capacity (entering and exiting a region) by NGTDM region and by Census Division
- Natural gas flows (entering and exiting a region) by NGTDM region and Census Division
- Natural gas pipeline capacity between NGTDM regions
- Natural gas flows between NGTDM regions
- Natural gas underground storage and pipeline capacity by NGTDM region
- Unaccounted for natural gas[96]

[96]Unaccounted for natural gas is a balancing item between the amount of natural gas consumed and the amount supplied. It includes reporting discrepancies, net storage withdrawals (in historical years), and differences due to convergence tolerance levels.

Appendix A. NGTDM Model Abstract

Model Name: Natural Gas Transmission and Distribution Module

Acronym: NGTDM

Title: Natural Gas Transmission and Distribution Module

Purpose: The NGTDM is the component of the National Energy Modeling System (NEMS) that represents the mid-term natural gas market. The purpose of the NGTDM is to derive natural gas supply and end-use prices and flow patterns for movements of natural gas through the regional interstate network. The prices and flow patterns are derived by obtaining a market equilibrium across the three main components of the natural gas market: the supply component, the demand component, and the transmission and distribution network that links them.

Status: ACTIVE

Use: BASIC

Sponsor:

- Office of Energy Analysis
- Office of Petroleum, Gas, and Biofuels Analysis, EI-33
- Model Contact: Joe Benneche
- Telephone: (202) 586-6132

Documentation: Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, June 2011).

Previous Documentation: Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, June 2010).

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Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Pipeline Tariff Module (PTM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, Apr 30, 1993.

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Paul R. Carpenter, PhD, Incentives Research, Inc. "Final Review of the National Energy Modeling System (NEMS) Natural Gas Transmission and Distribution Model (NGTDM)." Boston, MA, Jan 4, 1995.

Archival: The NGTDM is archived as a component of the NEMS on compact disc storage compatible with the PC multiprocessor computing platform upon completion of the NEMS production runs to generate the *Annual Energy Outlook 2011*, DOE/EIA-0383(2011). The archive package can be downloaded from ftp://ftp.eia.doe.gov/pub/forecasts/aeo.

Energy System Covered: The NGTDM models the U.S. natural gas transmission and distribution network that links the suppliers (including importers) and consumers of natural gas, and in so doing determines the regional market clearing natural gas end-use and supply (including border) prices.

Coverage: Geographic: Demand regions are the 12 NGTDM regions, which are based on the nine Census Divisions with Census Division 5 split further into South Atlantic and Florida, Census Division 8 split further into Mountain and Arizona/New Mexico, and Census Division 9 split further into California and Pacific with Alaska and Hawaii handled separately. Production is represented in the lower 48 at 17 onshore and 3 offshore regions. Import/export border crossings include three at the Mexican border, seven at the Canadian border, and 12 liquefied natural gas import terminals. In a separate component, potential liquefied natural gas production and liquefaction for U.S. import is represented for 14 international ports. A simplified Canadian representation is subdivided into an eastern and western region, with potential LNG import facilities on both shores. Consumption, production, and LNG imports to serve the Mexico gas market are largely assumption based and serve to set the level of exports to Mexico from the United States.

Time Unit/Frequency: Annually through 2035, including a peak (December through March) and off-peak forecast.

Product(s): Natural gas

Economic Sector(s): Residential, commercial, industrial, electric generators and transportation

Data Input Sources:
(Non-DOE)
- The Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU), Section 1113.
  —Federal vehicle natural gas (VNG) taxes

- Canadian Association of Petroleum Producers Statistical Handbook
  — Historical Canadian supply and consumption data
- Mineral Management Service.
  — Revenues and volumes for offshore production in Texas, California, and Louisiana
- Foster Pipeline and Storage Financial Cost Data
  — pipeline and storage financial data
- Data Resources Inc., U.S. Quarterly Model
  — Various macroeconomic data
- *Oil and Gas Journal*, "Pipeline Economics"
  — Pipeline annual capitalization and operating revenues
- Board of Governors of the Federal Reserve System Statistical Release, "Selected Interest Rates and Bond Prices"
  — Real average yield on 10 year U.S. government bonds
- Hart Energy Network's Motor Fuels Information Center at www.hartenergynetowrk.com/motorfuels/state/doc/glance/glnctax.htm
  — compressed natural gas vehicle taxes by state
- National Oceanic and Atmospheric Association
  — State level heating degree days
- U.S. Census
  — State level population data for heating degree day weights
- Natural Gas Week
  — Canada storage withdrawal and capacity data
- PEMEX Prospective de Gas Natural
  — Historical Mexico raw gas production by region
- Informes y Publicaciones, Anuario Estadísticas, Estadísticas Operativas, Producción de gas natural
  — Historical Mexico raw gas production by region
- Sener Prospectiva del Mercado de gas natural 2006-2015
  — Mexico LNG import projections

Data Input Sources:

(DOE) Forms and/or Publications:

- U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216.
  — Annual estimate of gas production for associated-dissolved and nonassociated categories by State/sub-state.
- Natural Gas Annual, DOE/EIA-0131.
  — By state -- natural gas consumption by sector, dry production, imports, exports, storage injections and withdrawals, balancing item, state transfers, number of residential customers, fraction of industrial market represented by historical prices, and wellhead, city gate, and end-use prices.
  — Supplemental supplies
- Natural Gas Monthly, DOE/EIA-0130.
  — By month and state – natural gas consumption by sector, marketed production, net storage withdrawals, end-use prices by sector, city gate prices

— By month – quantity and price of imports and exports by country, wellhead prices, lease and plant consumption, pipeline consumption, supplemental supplies

- State Energy Data System (SEDS).
  — State level annual delivered natural gas prices when not available in the Natural Gas Annual.
- Electric Power Monthly, DOE/EIA-0226.
  — Monthly volume and price paid for natural gas by electric generators
- *Annual Energy Review*, DOE/EIA-0384
  — Gross domestic product and implicit price deflator
- EIA-846, "Manufacturing Energy Consumption Survey"
  — Base year average annual core industrial end-use prices
- *Short-Term Energy Outlook*, DOE/EIA-0131.
  — National natural gas projections for first two years beyond history
  — Historical natural gas prices at the Henry Hub
- Department of Energy, *Natural Gas Imports and Exports*, Office of Fossil Energy
  — Import and export volumes and prices by border location
- Department of Energy, Alternate Fuels & Advanced Vehicles Data Center, including *Alternate Fuel Price Report*, Office of Energy Efficiency and Renewable Energy
  — Sample of retail prices paid for compressed natural gas for vehicles
  — State motor fuel taxes
- EIA-191, "Underground Gas Storage Report"
  — Used in part to develop working gas storage capacity data
- EIA-457, "Residential Energy Consumption Survey"
  — Number of residential natural gas customers
- International Energy Outlook, DOE/EIA-0484.
  — Projection of natural gas consumption in Canada and Mexico.
- International Energy Annual, DOE/EIA-0484.
  — Historical natural gas data on Canada and Mexico.

Models and other:

- National Energy Modeling System (NEMS)
  — Domestic supply and demand representations are provided interactively as inputs to the NGTDM from other NEMS models
- International Natural Gas Model (INGM)
  — Provides information for setting LNG supply curves exogenously in the NGTDM

General Output Descriptions:

- Average natural gas end-use prices levels by sector and region
- Average natural gas production volumes and prices by region
- Average natural gas import and export volumes and prices by region and type
- Pipeline fuel consumption by region
- Lease and plant fuel consumption by region

- Lease and plant fuel consumption by region
- Flow of gas between regions by peak and off-peak period
- Pipeline capacity additions and utilization levels by arc
- Storage capacity additions by region

Related Models: NEMS (part of)

Model Features:

- Model Structure: Modular; three major components: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS).
  - — ITS Integrating submodule of the NGTDM. Simulates the natural gas price determination process by bringing together all major economic and technological factors that influence regional natural gas trade in the United States. Determines natural gas production and imports, flows and prices, pipeline capacity expansion and utilization, storage capacity expansion and utilization for a simplified network representing the interstate natural gas pipeline system
  - — PTS Develops parameters for setting tariffs in the ITM for transportation and storage services provided by interstate pipeline companies
  - — DTS Develops markups for distribution services provided by LDC's and intrastate pipeline companies.

- Modeling Technique:
  - — ITS, Heuristic algorithm, operates iteratively until supply/demand convergence is realized across the network
  - — PTS, Econometric estimation and accounting algorithm
  - — DTS, Econometric estimation
  - — Canada and Mexico supplies based on a combination of estimated equations and basic assumptions.

Model Interfaces: NEMS

Computing Environment:

- Hardware Used: Personal Computer
- Operating System: UNIX simulation
- Language/Software Used: FORTRAN
- Storage Requirement: 2,700K bytes for input data storage; 1,100K bytes for source code storage; and 17,500K bytes for compiled code storage
- Estimated Run Time: Varies from NEMS iteration and from computer processor, but rarely exceeds a quarter of a second per iteration and generally is less than 5 hundredths of a second.

Status of Evaluation Efforts:

Model developer's report entitled "Natural Gas Transmission and Distribution Model, Model Developer's Report for the National Energy Modeling System," dated November 14, 1994.

Date of Last Update: January 2011.

Appendix B. References

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Carpenter, Paul R., "Review of the Gas Analysis Modeling System (GAMS), Final Report of Findings and Recommendations" (Boston: Incentives Research, Inc., August 1991).

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Forbes, Kevin, Science Applications International Corporation, "Efficiency in the Natural Gas Industry," Task 93-095 Deliverable under Contract No. DE-AC01-92-EI21944 for Natural Gas Analysis Branch of the Energy Information Administration, January 31, 1995.

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Gas Technology Institute, "Liquefied Natural Gas (LNG) Methodology Enhancements in NEMS," report submitted to Energy Information Administration, March 2003.

Interstate Natural Gas Association of America (INGAA), "Availability, Economics & Production Potential of North American Unconventional Natural Gas Supplies," November 2008, written by ICF.

National Energy Board, *Canada's Energy Future: Scenarios for Supply and Demand to 2025*, 2003

Oil and Gas Journal, "Pipeline Economics," published annually in various editions.

Woolridge, Jeffrey M., Introductory Econometrics: A Modern Approach, South-Western College Publishing, 2000.

Appendix C. NEMS Model Documentation Reports

The National Energy Modeling System is documented in a series of 15 model documentation reports, most of which are updated on an annual basis. Copies of these reports are available by contacting the National Energy Information Center, 202/586-8800.

Energy Information Administration, *National Energy Modeling System Integrating Module Documentation Report*, DOE/EIA-M057.

Energy Information Administration, *Model Documentation Report: Macroeconomic Activity Module of the National Energy Modeling System*.

Energy Information Administration, *Documentation of the D.R.I. Model of the U.S. Economy*.

Energy Information Administration, *National Energy Modeling System International Energy Model Documentation Report*.

Energy Information Administration, *World Oil Refining, Logistics, and Demand Model Documentation Report*.

Energy Information Administration, *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation Report: Transportation Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Documentation of the Electricity Market Module*.

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Energy Information Administration, *EIA Model Documentation: Petroleum Market Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation: Coal Market Module*.

Energy Information Administration, *Model Documentation Report: Renewable Fuels Module*.

Appendix D. Model Equations

This appendix presents the mapping of each equation (by equation number) in the documentation with the subroutine in the NGTDM code where the equation is used or referenced.

Chapter 2 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
1	NGDMD_CRVF* (core), NGDMD_CRVI* (noncore)
2-19	NGSUP_PR*
20-25	NGOUT_CAN
26-39	NGCAN_FXADJ
40	NGOUT_MEX
41	NGSETLNG_INGM
42-54	NGTDM_DMDALK

Chapter 4 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
55, 58	NGSET_NODEDMD, NGDOWN_TREE
56, 59	NGSET_NODECDMD
57, 60	NGSET_YEARCDMD
61, 62	NGDOWN_TREE
63	NGSET_INTRAFLO
64	NGSET_INTRAFLO
65	NGSHR_CALC
66	NGDOWN_TREE
67	NGSET_MAXFLO*
68-71	NGSET_MAXPCAP
72-76	NGSET_MAXFLO*
77-79	NGSET_ACTPCAP
80-81	NGSHR_MTHCHK
82-85	NGSET_SUPPR
86-87	NGSTEO_BENCHWPR
88	NGSTEO_BENCHWPR
89-90	NGSET_ARCFEE

91-94	NGUP_TREE
95	NGSET_STORPR
96-97	NGUP_TREE
98	NGCHK_CONVNG
99	NGSET_SECPR
100	NGSET_BENCH, HNGSET_CGPR
101-106	NGSET_SECPR

Chapter 5 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
107-118	NGDTM_FORECAST_DTARF
119-120	NGDTM_FORECAST_TRNF
121-126	NGTDM_CNGBUILD

Chapter 6 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
127-132, 136-154, 203-205	NGPREAD
133-135, 155-156	NGPIPREAD
176-194, 206, 208-221	NGPSET_PLCOS_COMPONENTS
157-166, 172, 207, 222-231, 238	NGPSET_PLINE_COSTS
167-171, 232-237, 238-243	NGPIPE_VARTAR*
251-253	NGSTREAD
244-250, 254-256, 260-287	NGPSET_STCOS_COMPONENTS
257-259	NGPST_DEVCONST
173-175, 288-292	X1NGSTR_VARTAR*
195-202	(accounting relationships, not part of code)
293-205	NGFRPIPE_TAR*

Appendix E. Model Input Variable Mapped to Data Input Files

This appendix provides a list of the FORTRAN variables, and their associated input files, that are assigned values through FORTRAN READ statements in the source code of the NGTDM. Information about all of these variables and their assigned values (including sources, derivations, units, and definitions) are provided in the indicated input files of the NGTDM. The data file names and versions used for the *AEO2011* are identified below. These files are located on the EIA NEMS-F8 NT server. Electronic copies of these input files are available as part of the NEMS2011 archive package. The archive package can be downloaded from ftp://ftp.eia.doe.gov/pub/forecasts/aeo. In addition, the files are available upon request from Joe Benneche at (202) 586-6132 or Joseph.Benneche@eia.doe.gov.

ngcan.txt	V1.68	nghismn.txt	V1.30	ngptar.txt	V1.26
ngcap.txt	V1.32	nglngdat.txt	V1.79	nguser.txt	V1.150
ngdtar.txt	V1.38	ngmap.txt	V1.7		
nghisan.txt	V1.35	ngmisc.txt	V1.155		

Variable	File
ACTPCAP	NGCAN
ACTPCAP	NGCAP
ADDYR	NGCAP
ADJ_PIP	NGPTAR
ADJ_STR	NGPTAR
ADW	NGHISAN
AFR_CMEN	NGPTAR
AFR_DDA	NGPTAR
AFR_DIT	NGPTAR
AFR_FSIT	NGPTAR
AFR_LTDN	NGPTAR
AFR_OTTAX	NGPTAR
AFR_PFEN	NGPTAR
AFR_TOM	NGPTAR
AFX_CMEN	NGPTAR
AFX_DDA	NGPTAR
AFX_DIT	NGPTAR
AFX_FSIT	NGPTAR
AFX_LTDN	NGPTAR
AFX_OTTAX	NGPTAR
AFX_PFEN	NGPTAR
AFX_TOM	NGPTAR
AK_C	NGMISC
AK_CM	NGMISC
AK_CN	NGMISC
AK_D	NGMISC
AK_E	NGMISC
AK_EM	NGMISC
AK_ENDCONS_N	NGMISC
AK_F	NGMISC
AK_G	NGMISC
AK_HDD	NGMISC
AK_IN	NGMISC
AK_PCTLSE	NGMISC
AK_PCTPIP	NGMISC
AK_PCTPLT	NGMISC
AK_POP	NGMISC
AK_QIND_S	NGMISC
AK_RM	NGMISC
AK_RN	NGMISC
AKPIP1	NGMISC
AKPIP2	NGMISC
AL_ADJ	NGHISAN
AL_OFFD	NGHISAN
AL_OFST	NGHISAN
AL_OFST2	NGHISAN
AL_ONSH	NGHISAN
AL_ONSH2	NGHISAN
ALB_TO_L48	NGMISC
ALNGA	NGLNGDAT
ALNGB	NGLNGDAT
ALPHA_PIPE	NGPTAR
ALPHA_STR	NGPTAR
ALPHA2_PIPE	NGPTAR
ALPHA2_STR	NGPTAR
ALPHAFAC	NGUSER

Variable	File
ANUM	NGMAP
ARC_FIXTAR	NGCAN
ARC_VARTAR	NGCAN
AVGCOST	NGPTAR
AVR_CMEN	NGPTAR
AVR_DDA	NGPTAR
AVR_DIT	NGPTAR
AVR_FSIT	NGPTAR
AVR_LTDN	NGPTAR
AVR_OTTAX	NGPTAR
AVR_PFEN	NGPTAR
AVR_TOM	NGPTAR
BA_PREM	NGMISC
BAJA_CAP	NGMISC
BAJA_FIX	NGMISC
BAJA_LAG	NGMISC
BAJA_MAX	NGMISC
BAJA_PRC	NGMISC
BAJA_STAGE	NGMISC
BAJA_STEP	NGMISC
BEQ_BLDAVG	NGMISC
BEQ_BLDHRSK	NGMISC
BEQ_OPRAVG	NGMISC
BEQ_OPRHRSK	NGMISC
BNEWCAP_2003_2004	NGPTAR
BNEWCAP_POST2004	NGPTAR
BNEWCAP_PRE2003	NGPTAR
BPPRC	NGCAN
BPPRCGR	NGCAN
CAN_XMAPCN	NGMAP
CAN_XMAPUS	NGMAP
CANEXP	NGCAN
CM_ADJ	NGDTAR
CM_ALP	NGDTAR
CM_LNQ	NGDTAR
CM_PKALP	NGDTAR
CM_RHO	NGDTAR
CN_DMD	NGCAN
CN_FIXSHR	NGCAN
CN_FIXSUP	NGCAN
CN_OILSND	NGCAN
CN_UNPRC	NGCAN
CN_WOP	NGCAN
CNCAPSW	NGUSER
CNG_BUILDCOST	NGDTAR
CNG_HRZ	NGDTAR
CNG_MARKUP	NGDTAR
CNG_RETAIL_MARKUP	NGDTAR
CNG_WACC	NGDTAR
CNPER_YROPEN	NGCAP
CNPLANYR	NGCAN
CON	NGHISMN
CON_ELCD	NGHISMN
CON_EPMGR	NGHISMN
CONNOL_ELAS	NGCAN

Variable	File	Variable	File
CTG_BASCGG	NGMISC	D_DIT	NGPTAR
CTG_BASCGGCO2	NGMISC	D_FLO	NGPTAR
CTG_BASCGS	NGMISC	D_FSIT	NGPTAR
CTG_BASCGSCO2	NGMISC	D_GCMES	NGPTAR
CTG_BASCOL	NGMISC	D_GLTDS	NGPTAR
CTG_BASHHV	NGMISC	D_GPFES	NGPTAR
CTG_BASSIZ	NGMISC	D_GPIS	NGPTAR
CTG_BCLTON	NGMISC	D_GPIS	NGPTAR
CTG_BLDX	NGMISC	D_LTDN	NGPTAR
CTG_BLDX	NGMISC	D_LTDR	NGPTAR
CTG_BLDYRS	NGMISC	D_LTDR	NGPTAR
CTG_CAPYR$	NGMISC	D_LTDS	NGPTAR
CTG_CO2	NGMISC	DMAP	NGMAP
CTG_DCLCAPCST	NGMISC	D_MXPKFLO	NGPTAR
CTG_DCLOPRCST	NGMISC	D_NPIS	NGPTAR
CTG_FSTYR	NGMISC	D_NPIS	NGPTAR
CTG_IINDX	NGMISC	D_OTTAX	NGPTAR
CTG_INCBLD	NGMISC	D_OTTAX	NGPTAR
CTG_INVLOC	NGMISC	D_PFEN	NGPTAR
CTG_NAM	NGMISC	D_PFER	NGPTAR
CTG_NCL	NGMISC	D_PFER	NGPTAR
CTG_OH_LCFAC	NGMISC	D_PFES	NGPTAR
CTG_OSBLFAC	NGMISC	D_TCAP	NGPTAR
CTG_PCTCNTG	NGMISC	D_TOM	NGPTAR
CTG_PCTENV	NGMISC	D_TOM	NGPTAR
CTG_PCTLND	NGMISC	D_WCAP	NGPTAR
CTG_PCTSPECL	NGMISC	DDA_NEWCAP	NGPTAR
CTG_PCTWC	NGMISC	DDA_NPIS	NGPTAR
CTG_PRJLIFE	NGMISC	DECL_GASREQ	NGCAN
CTG_PUCAP	NGMISC	DEXP_FRMEX	NGMISC
CTG_SINVST	NGMISC	DFAC_TOMEX	NGMISC
CTG_STAFF_LCFAC	NGMISC	DFR	NGCAN
CWC_DISC	NGPTAR	DFR	NGCAN
CWC_K	NGPTAR	DMASP	NGCAN
CWC_RHO	NGPTAR	DMASP	NGCAN
CWC_TOM	NGPTAR	EL_ALP	NGDTAR
D_ADDA	NGPTAR	EL_CNST	NGDTAR
D_ADDA	NGPTAR	EL_PARM	NGDTAR
D_ADIT	NGPTAR	EL_RESID	NGDTAR
D_ADIT	NGPTAR	EL_RHO	NGDTAR
D_APRB	NGPTAR	ELE_GFAC	NGMISC
D_APRB	NGPTAR	EMMSUB_EL	NGMAP
D_CMEN	NGPTAR	EMMSUB_NG	NGMAP
D_CMER	NGPTAR	EMRP_BLDAVG	NGMISC
D_CMER	NGPTAR	EMRP_BLDHRSK	NGMISC
D_CMES	NGPTAR	EMRP_OPRAVG	NGMISC
D_CONST	NGPTAR	EMRP_OPRHRSK	NGMISC
D_CONST	NGPTAR	EQUITY_BLDAVG	NGMISC
D_CONST	NGPTAR	EQUITY_BLDHRSK	NGMISC
D_CONST	NGPTAR	EQUITY_OPRAVG	NGMISC
D_CWC	NGPTAR	EQUITY_OPRHRSK	NGMISC
D_CWC	NGPTAR	EXP_A	NGPTAR
D_DDA	NGPTAR	EXP_B	NGPTAR
D_DDA	NGPTAR	EXP_C	NGPTAR
D_DIT	NGPTAR	EXP_FRMEX	NGMISC

Variable	File	Variable	File
FDGOM	NGHISMN	HELE_SHR	NGMISC
FDIFF	NGDTAR	HFAC_GPIS	NGPTAR
FE_CCOST	NGMISC	HFAC_REV	NGPTAR
FE_EXPFAC	NGMISC	HHDD	NGDTAR
FE_FR_TOM	NGMISC	HI_RN	NGMISC
FE_PFUEL_FAC	NGMISC	HIND_SHR	NGMISC
FE_R_STTOM	NGMISC	HISTRESCAN	NGCAN
FE_R_TOM	NGMISC	HISTWELCAN	NGCAN
FE_STCCOST	NGMISC	HNETINJ	NGCAN
FE_STEXPFAC	NGMISC	HNETWTH	NGCAN
FEDTAX_RT	NGMISC	HNETWTH	NGHISMN
FIXLNGFLG	NGMAP	HPEMEX_SHR	NGMISC
FLO_THRU_IN	NGCAN	HPIMP	NGHISAN
FMASP	NGCAN	HPKSHR_FLOW	NGMISC
FMASP	NGCAN	HPKUTZ	NGCAP
FR_AVGTARYR	NGMISC	HPRC	NGHISMN
FR_BETA	NGMISC	HPSUP	NGCAN
FR_CAPITL0	NGMISC	HQIMP	NGHISAN
FR_CAPYR	NGMISC	HQSUP	NGCAN
FR_DEBTRATIO	NGMISC	HQTY	NGHISMN
FR_DISCRT	NGMISC	HRC_SHR	NGMISC
FR_ESTNYR	NGMISC	HW_ADJ	NGDTAR
FR_OTXR	NGMISC	HW_BETA0	NGDTAR
FR_PADDTAR	NGMISC	HW_BETA1	NGDTAR
FR_PCNSYR	NGMISC	HW_RHO	NGDTAR
FR_PDRPFAC	NGMISC	HYEAR	NGHISAN
FR_PEXPFAC	NGMISC	ICNBYR	NGCAN
FR_PFUEL	NGMISC	IEA_CON	NGMISC
FR_PMINWPR	NGMISC	IEA_PRD	NGMISC
FR_PMINYR	NGMISC	IMASP	NGCAN
FR_PPLNYR	NGMISC	IMASP	NGCAN
FR_PRISK	NGMISC	IMP_TOMEX	NGMISC
FR_PTREAT	NGMISC	IN_ALP	NGDTAR
FR_PVOL	NGMISC	IN_CNST	NGDTAR
FR_ROR_PREM	NGMISC	IN_DIST	NGDTAR
FR_TOM0	NGMISC	IN_LNQ	NGDTAR
FR_TXR	NGMISC	IN_PKALP	NGDTAR
FRATE	NGPTAR	IN_RHO	NGDTAR
FREE_YRS	NGDTAR	IND_GFAC	NGMISC
FRMETH	NGCAN	INFL_RT	NGMISC
FSRGN	NGMAP	INIT_GASREQ	NGCAN
FSTYR_GOM	NGHISAN	INS_FAC	NGMISC
FTAX	NGDTAR	INTRAREG_TAR	NGDTAR
FUTWTS	NGMISC	INTRAST_TAR	NGDTAR
GAMMAFAC	NGUSER	IPR	NGCAN
GDP_B87	NGMISC	IRES	NGCAN
GOF_AL	NGHISAN	IRG	NGCAN
GOF_CA	NGHISAN	IRIGA	NGCAN
GOF_LA	NGHISAN	IRIGA	NGCAN
GOF_TX	NGHISAN	JNETWTH	NGHISMN
HAFLOW	NGMISC	LA_OFFD	NGHISAN
HCG_BENCH	NGDTAR	LA_OFST	NGHISAN
HCGPR	NGHISAN	LA_ONSH	NGHISAN
HCUMSUCWEL	NGCAN	LABORLOC	NGMISC
HDYWHTLAG	NGDTAR	LEVELYRS	NGPTAR

Variable	File	Variable	File
LNG_XMAP	NGMAP	NGDBGRPT	NGUSER
LNGA	NGLNGDAT	NIND_SHR	NGMISC
LNGB	NGLNGDAT	NINJ_TOT	NGHISMN
LNGCAP	NGLNGDAT	NLNGA	NGLNGDAT
LNGCRVOPT	NGLNGDAT	NLNGB	NGLNGDAT
LNGDATA	NGMISC	NLNGPTS	NGLNGDAT
LNGDIF_GULF	NGLNGDAT	NNETWITH	NGUSER
LNGDIFF	NGMISC	NOBLDYR	NGUSER
LNGFIX	NGLNGDAT	NODE_ANGTS	NGMAP
LNGMIN	NGLNGDAT	NODE_SNGCOAL	NGMAP
LNGPPT	NGLNGDAT	NONU_ELAS_F	NGDTAR
LNGPS	NGLNGDAT	NONU_ELAS_I	NGDTAR
LNGQPT	NGLNGDAT	NPEMEX_SHR	NGMISC
LNGQS	NGLNGDAT	NPROC	NGMAP
LNGTAR	NGLNGDAT	NQPF_TOT	NGHISMN
LSTYR_MMS	NGHISAN	NRC_SHR	NGMISC
MAINT_FAC	NGMISC	NRCI_INV	NGMISC
MAP_NG	NGMAP	NRCI_LABOR	NGMISC
MAP_NRG_CRG	NGDTAR	NRCI_OPER	NGMISC
MAP_OG	NGMAP	NSRGN	NGMAP
MAP_PRDST	NGHISMN	NSTAT	NGDTAR
MAP_STSUB	NGHISAN	NSTSTOR	NGHISMN
MAPLNG_NEW	NGMAP	NSUPLM_TOT	NGHISMN
MAPLNG_NG	NGMAP	NUM_REGSHR	NGDTAR
MAX_CNG_BUILD	NGDTAR	NUMRS	NGDTAR
MAXCYCLE	NGUSER	NWTH_TOT	NGHISMN
MAXPLNG	NGLNGDAT	NYR_MISS	NGHISAN
MAXPRRFAC	NGMISC	OCSMAP	NGMAP
MAXPRRNG	NGMISC	oEL_MRKUP_BETA	NGDTAR
MAXUTZ	NGCAP	oEL_MRKUP_BETA	NGDTAR
MBAJA	NGMISC	OEQGCELGR	NGMISC
MDPIP1	NGMISC	OEQGFELGR	NGMISC
MDPIP2	NGMISC	OEQGIELGR	NGMISC
MEX_XMAP	NGMAP	OF_LAST	NGHISAN
MEX_XMAP	NGMAP	OOGHHPRNG	NGMISC
MEXEXP_SHR	NGMISC	OOGQNGEXP	NGMISC
MEXIMP_SHR	NGMISC	OPPK	NGCAP
MEXLNG	NGMISC	OPTCOM	NGDTAR
MEXLNGMIN	NGLNGDAT	OPTELO	NGDTAR
MISC_GAS	NGHISAN	OPTELP	NGDTAR
MISC_OIL	NGHISAN	OPTIND	NGDTAR
MISC_ST	NGHISAN	OPTRES	NGDTAR
MON_PEXP	NGHISMN	OQGCELGR	NGMISC
MON_PIMP	NGHISMN	OQGFEL	NGMISC
MON_QEXP	NGHISMN	OQGFELGR	NGMISC
MON_QIMP	NGHISMN	OQGIEL	NGMISC
MONMKT_PRD	NGHISMN	OQGIELGR	NGMISC
MSPLIT_STSUB	NGHISAN	OQNGEL	NGMISC
MUFAC	NGUSER	OSQGFELGR	NGMISC
NAW	NGHISAN	OSQGIELGR	NGMISC
NCNMX	NGCAN	OTH_FAC	NGMISC
NELE_SHR	NGMISC	PARM_LNGCRV3	NGLNGDAT
NG_CENMAP	NGMAP	PARM_LNGCRV5	NGLNGDAT
NGCFEL	NGHISMN	PARM_LNGELAS	NGLNGDAT
NGDBGCNTL	NGUSER	PARM_MINPR	NGUSER

Variable	File	Variable	File
PARM_SUPCRV3	NGUSER	QOF_GM	NGHISAN
PARM_SUPCRV5	NGUSER	QOF_LA	NGHISAN
PARM_SUPELAS	NGUSER	QOF_LAFD	NGHISAN
PCLADJ	NGMISC	QOF_MS	NGHISAN
PCNT_R	NGPTAR	QOF_TX	NGHISAN
PCT_AL	NGHISAN	QSUP_DELTA	NGUSER
PCT_LA	NGHISAN	QSUP_SMALL	NGUSER
PCT_MS	NGHISAN	QSUP_WT	NGUSER
PCT_TX	NGHISAN	RC_GFAC	NGMISC
PCTADJSHR	NGUSER	RECS_ALIGN	NGDTAR
PCTFLO	NGUSER	RESBASE	NGCAN
PEAK	NGCAP	RESBASYR	NGCAN
PEMEX_GFAC	NGMISC	RESTECH	NGCAN
PEMEX_PRD	NGMISC	RETAIL_COST	NGDTAR
PER_YROPEN	NGCAP	REV	NGHISMN
PERFDTX	NGHISAN	RGRWTH	NGCAN
PERMG	NGDTAR	RGRWTH	NGCAN
PIPE_FACTOR	NGPTAR	ROF_AL	NGHISAN
PKOPMON	NGMISC	ROF_CA	NGHISAN
PKSHR_CDMD	NGCAN	ROF_GM	NGHISAN
PKSHR_PROD	NGCAN	ROF_LA	NGHISAN
PLANPCAP	NGCAP	ROF_MS	NGHISAN
PLANPCAP	NGCAP	ROF_TX	NGHISAN
PMMMAP_NG	NGMAP	RS_ADJ	NGDTAR
PNGIMP	NGLNGDAT	RS_ALP	NGDTAR
PRAT	NGCAN	RS_COST	NGDTAR
PRAT	NGCAN	RS_LNQ	NGDTAR
PRC_EPMCD	NGHISMN	RS_PARM	NGDTAR
PRC_EPMGR	NGHISMN	RS_PKALP	NGDTAR
PRCWTS	NGMISC	RS_RHO	NGDTAR
PRCWTS2	NGMISC	SCEN_DIV	NGHISAN
PRD_GFAC	NGMISC	SCH_ID	NGHISAN
PRD_MLHIS	NGHISMN	SELE_SHR	NGMISC
PRICE_AL	NGHISAN	SHR_OPT	NGUSER
PRICE_CA	NGHISAN	SIM_EX	NGHISAN
PRICE_LA	NGHISAN	SIND_SHR	NGMISC
PRICE_TX	NGHISAN	SITM_RG	NGHISAN
PRJSDECOM	NGMISC	SNG_EM	NGHISAN
PRMETH	NGCAN	SNG_OG	NGHISAN
PROC_ORD	NGMAP	SNGCOAL	NGHISAN
PSUP_DELTA	NGUSER	SNGCOAL	NGMISC
PTCURPCAP	NGCAP	SNGLIQ	NGHISAN
PTMAXPCAP	NGCAN	SPCNEWFAC	NGPTAR
PTMBYR	NGPTAR	SPCNODID	NGPTAR
PTMSTBYR	NGPTAR	SPCNODID	NGPTAR
PUTL_POW	NGHISAN	SPCNODN	NGPTAR
Q23TO3	NGCAN	SPCPNODBAS	NGPTAR
QAK_ALB	NGMISC	SPEMEX_SHR	NGMISC
QLP_LHIS	NGHISMN	SPIN_PER	NGHISAN
QMD_ALB	NGMISC	SRATE	NGPTAR
QNGIMP	NGLNGDAT	SRC_SHR	NGMISC
QOF_AL	NGHISAN	STADIT_ADIT	NGPTAR
QOF_ALFD	NGHISAN	STADIT_C	NGPTAR
QOF_ALST	NGHISAN	STADIT_NEWCAP	NGPTAR
QOF_CA	NGHISAN	STAX	NGDTAR

Variable	File
STCCOST_BETAREG	NGPTAR
STCCOST_CREG	NGPTAR
STCWC_CREG	NGPTAR
STCWC_RHO	NGPTAR
STCWC_TOTCAP	NGPTAR
STDDA_CREG	NGPTAR
STDDA_NEWCAP	NGPTAR
STDDA_NPIS	NGPTAR
STDISCR	NGUSER
STENDCON	NGUSER
STEOYRS	NGUSER
STEP_CN	NGCAN
STEP_MX	NGCAN
STLNGIMP	NGUSER
STLNGRG	NGUSER
STLNGRGN	NGUSER
STLNGYR	NGUSER
STLNGYRN	NGUSER
STOGPRSUP	NGUSER
STOGWPRNG	NGUSER
STPHAS_YR	NGUSER
STPIN_FLG	NGUSER
STPNGCM	NGUSER
STPNGEL	NGUSER
STPNGIN	NGUSER
STPNGRS	NGUSER
STQGPTR	NGUSER
STQLPIN	NGUSER
STR_EFF	NGPTAR
STR_FACTOR	NGPTAR
STRATIO	NGPTAR
STSCAL_CAN	NGUSER
STSCAL_DISCR	NGUSER
STSCAL_FPR	NGUSER
STSCAL_IPR	NGUSER
STSCAL_LPLT	NGUSER
STSCAL_NETSTR	NGUSER
STSCAL_PFUEL	NGUSER
STSCAL_SUPLM	NGUSER
STSCAL_WPR	NGUSER

Variable	File
STSTATE	NGHISMN
STTAX_RT	NGMISC
STTOM_C	NGPTAR
STTOM_RHO	NGPTAR
STTOM_WORKCAP	NGPTAR
STTOM_YR	NGPTAR
SUPARRAY	NGMAP
SUPCRV	NGUSER
SUPREG	NGMAP
SUPSUB_NG	NGMAP
SUPSUB_OG	NGMAP
SUPTYPE	NGMAP
SUTZ	NGCAP
SUTZ	NGCAP
TAX_FAC	NGMISC
TFD	NGDTAR
TFDYR	NGDTAR
TOM_BYEAR	NGPTAR
TOM_BYEAR_EIA	NGPTAR
TOM_DEPSHR	NGPTAR
TOM_GPIS1	NGPTAR
TOM_K	NGPTAR
TOM_RHO	NGPTAR
TOM_YR	NGPTAR
TRN_DECL	NGDTAR
TTRNCAN	NGCAN
URES	NGCAN
URES	NGCAN
URG	NGCAN
URG	NGCAN
UTIL_ELAS_F	NGDTAR
UTIL_ELAS_I	NGDTAR
WHP_LHIS	NGHISMN
WLMETH	NGCAN
WPR4CAST_FLG	NGUSER
XBLD	NGCAP
XBM_ISBL	NGMISC
XBM_LABOR	NGMISC
YDCL_GASREQ	NGCAN

Appendix F. Derived Data

Table F1

Data: Parameter estimates for the Alaskan natural gas consumption equations for the residential and commercial sectors and the Alaskan natural gas wellhead price.

Author: Tony Radich, EIA, June 2007, reestimated by Margaret Leddy, EIA, July 2009

Source: *Natural Gas Annual*, DOE/EIA-0131.

Derivation: Annual data from 1974 through 2008 were transformed into logarithmic form, tested for unit roots, and examined for simple correlations. When originally estimated, heating degree day quantity was calculated using a five-year average, but was statistically insignificant in both the residential and commercial cases and dropped from the final estimations. Lags of dependent variables were added as needed to remove serial correlation from residuals. Heteroskedasticity-consistent standard error estimators were also used as needed.

Residential Natural Gas Consumption

The forecast equation for residential natural gas consumption is estimated below:

$$LN\_CONS\_RES = (\beta_0*(1-\beta_{-1}) + (\beta_1*(1-\beta_{-1})*LN\_RES\_CUST) + (\beta_{-1}*(LN\_CONS\_RES(-1)*1000)))/1000.$$

where,

LN_CONS_RES	=	natural log of Alaska residential natural gas consumption in MMcf
LN_RES_CUST	=	natural log of thousands of Alaska residential gas customers. See the forecast equation for Alaska residential gas customers in Table F2.
(-1)	=	first lag

All variables are annual from 1974 through 2008.

Regression Diagnostics and Parameters Estimates:

Dependent Variable: LN_CONS_RES
Method: Least Squares
Date: 07/03/07
Sample (adjusted): 1974 – 2008
Included observations: 35 after adjustments
Newey-West HAC Standard Errors & Covariance (lag truncation=3)

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
C	6.983794	0.608314	11.48058	0.0000	β_0
LN_RES_CUST	0.601932	0.136919	4.396257	0.0001	β_1
AR(-1)	0.364042	0.117856	3.088872	0.0041	β_{-1}

R-squared	0.788754	Mean dependent var	9.486861
Adjusted R-squared	0.775552	S.D. dependent var	0.329138
S.E. of regression	0.155932	Akaike info criterion	-0.79697
Sum squared resid	0.778077	Schwarz criterion	-0.66366
Log likelihood	16.94702	Hannan-Quinn criter.	-0.75095
F-statistic	59.74123	Durbin-Watson stat	1.957789
Prob(F-statistic)	0.00000		

The equation for the Alaska residential natural gas consumption translates into the following forecast equation in the code:

AKQTY_F(1) = (exp(6.983794 * (1 - 0.364042)) * (AK_RN(t))**(0.601932 * (1 - 0.364042)) * (PREV_AKQTY(1,t-1)*1000)** (0.364042))/1000.

where,

AKQTY_F(1) = residential Alaskan natural gas consumption, (Bcf)
PREV_AKQTY(1,t-1) = previous year's residential Alaskan natural gas consumption, (Bcf)
AK_RN(t) = residential consumers (thousands) at current year. See Table F2

Commercial Natural Gas Consumption

The forecast equation for commercial natural gas consumption is estimated below:

LN_CONS_COM = $(\beta_0*(1 - \beta_{-1}) + (\beta_1$*LN_COM_CUST) + $(-\beta_{-1}* \beta_1)$*LN_COM_CUST(-1) + $(\beta_{-1}*$ LN_CONS_COM(-1)*1000))/1000.

where,

LN_CONS_COM = natural log of Alaska commercial natural gas consumption in MMcf
LN_COM_CUST = natural log of thousands of Alaska commercial gas customers. See the forecast equation in Table F2.
(-1) = first lag

All variables are annual from 1974 through 2008.

Regression Diagnostics and Parameters Estimates:

Dependent Variable: LN_CONS_COM
Method: Least Squares
Date: 07/22/09 Time: 09:36
Sample (adjusted): 1974 2008
Included observations: 35 after adjustments
Convergence achieved after 9 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=3)

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
C	9.425307	0.229458	41.07648	0.0000	β_0
LN_COM_CUST	0.205020	0.115140	1.780615	0.0845	β_1
AR(1)	0.736334	0.092185	7.987556	0.0000	β_{-1}

R-squared	0.696834	Mean dependent var	9.885287
Adjusted R-squared	0.677886	S.D. dependent var	0.213360
S.E. of regression	0.121093	Akaike info criterion	-1.302700
Sum squared resid	0.469232	Schwarz criterion	-1.169385
Log likelihood	25.79725	Hannan-Quinn criter.	-1.256680
F-statistic	36.77630	Durbin-Watson stat	1.680652
Prob(F-statistic)	0.000000		

The equation in the code for the Alaska commercial natural gas consumption follows:

AKQTY_F(2) = (exp(9.425307 * (1 - 0.736334)) * (AK_CN(t)**(0.205020)) *
(AK_CN(t-1)**(-0.736334 * 0.205020)) *
(PREV_AKQTY(2,t-1)*1000.)**(0.736334)))/1000.

where,

AKQTY_F(2) = commercial Alaskan natural gas consumption, (Bcf)
PREV_AKQTY(2,t-1) = previous year's commercial Alaskan natural gas consumption, (Bcf)
AK_CN(t) = commercial consumers (thousands) at current year. See Table F2

Natural Gas Wellhead Price

The forecast equation for natural gas wellhead price is determined below:

$$\ln AK\_WPRC_t = \beta_{-1} * \ln AK\_WPRC_{t-1} + \beta_1 * (1 - \beta_{-1}) * \ln IRAC87$$

Dependent Variable: LN_WELLHEAD_PRICE
Method: Least Squares
Date: 07/22/09 Time: 13:25
Sample (adjusted): 1974 2008
Included observations: 35 after adjustments
Convergence achieved after 6 iterations

	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
LN_IRAC87	0.280760	0.101743	2.759499	0.0094	β_1
AR(1)	0.934077	0.040455	23.08940	0.0000	β_{-1}

R-squared	0.881227	Mean dependent var	0.135244
Adjusted R-squared	0.877628	S.D. dependent var	0.540629
S.E. of regression	0.189122	Akaike info criterion	-0.437408
Sum squared resid	1.180310	Schwarz criterion	-0.348531
Log likelihood	9.654637	Hannan-Quinn criter.	-0.406727
Durbin-Watson stat	2.121742		
Inverted AR Roots	.93		

The forecast equation becomes:

$$AK\_WPRC_t = AK\_WPRC_{t-1}^{0.934077} * oIT\_WOP_{y,1}^{(0.280760*(1-0.934077))}$$

where,

AK_WPRC_t	=	average natural gas wellhead price (1987$/Mcf) in year t.
AK_F	=	Parameters for Alaskan natural gas wellhead price (Appendix E).
$oIT\_WOP_{y,1}$ or IRAC87	=	World oil price (International Refinery Acquisition Cost) (1987$/barrel)
t	=	year index

Data used in estimating parameters in Tables F1 and F2

	(mmcf) Res_Cons	(mmcf) Com_Con	1987$/Mcf Res_Price	1987$/Mcf Com_Price	1987$/Mcf Wellhead Price	Thousand Population	HDD, Alaska	Thousand Res_ Cust	Thousand Com_ Cust	(2000=1) GDP defl	87$/bbl IRAC	Mbbl oil_prod
1973	5024	12277	3.61	1.79	0.34	336.4	12865	23	3	0.3185	9.38	
1974	4163	13106	3.33	1.83	0.36	348.1	12655	22	4	0.3473	26.39	
1975	10393	14415	3.14	1.87	0.58	384.1	12391	25	4	0.38	26.83	
1976	10917	14191	3	1.89	0.71	409.8	11930	28	4	0.402	24.55	
1977	11282	14564	2.93	2.29	0.68	418	12521	30	5	0.4275	24.88	
1978	12166	15208	2.82	2.11	0.83	411.6	11400	33	5	0.4576	23.31	
1979	7313	15862	2.53	1.52	0.77	413.7	11149	36	6	0.4955	32.01	
1980	7917	16513	2.34	1.44	0.99	419.8	10765	37	6	0.5404	45.9	
1981	7904	16149	2.41	1.73	0.77	434.3	11248	40	6	0.5912	45.87	587337
1982	10554	24232	2.09	1.86	0.74	464.3	11669	48	7	0.6273	39.15	618910
1983	10434	24693	2.62	2.18	0.82	499.1	10587	55	8	0.6521	32.89	625527
1984	11833	24654	2.69	2.24	0.79	524	12161	63	10	0.6766	31.25	630401
1985	13256	20344	2.95	2.48	0.78	543.9	11237	65	10	0.6971	28.34	666233
1986	12091	20874	3.34	2.6	0.51	550.7	11398	66	11	0.7125	14.38	681310
1987	12256	20224	3.21	2.41	0.94	541.3	11704	67.648	11.484	0.732	18.13	715955
1988	12529	20842	3.35	2.51	1.23	535	11116	68.612	11.649	0.7569	14.08	738143
1989	13589	21738	3.38	2.39	1.27	538.9	10884	69.54	11.806	0.7856	16.85	683979
1990	14165	21622	3.4	2.36	1.24	553.17	11101	70.808	11.921	0.8159	19.52	647309
1991	13562	20897	3.62	2.51	1.28	569.05	11582	72.565	12.071	0.8444	16.21	656349
1992	14350	21299	3.21	2.24	1.19	586.72	11846	74.268	12.204	0.8639	15.42	627322
1993	13858	20003	3.28	2.3	1.18	596.91	11281	75.842	12.359	0.8838	13.37	577495
1994	14895	20698	2.92	2.01	1.03	600.62	11902	77.67	12.475	0.9026	12.58	568951
1995	15231	24979	2.88	1.8	1.3	601.58	10427	79.474	12.584	0.9211	13.62	541654
1996	16179	27315	2.67	1.81	1.26	605.21	11498	81.348	12.732	0.9385	16.1	509999
1997	15146	26908	2.89	1.87	1.4	609.66	11165	83.596	12.945	0.9541	14.22	472949
1998	15617	27079	2.78	1.83	1	617.08	11078	86.243	13.176	0.9647	9.14	428850
1999	17634	27667	2.72	1.63	1.02	622	12227	88.924	13.409	0.9787	12.91	383199
2000	15987	26485	2.62	1.51	1.29	627.53	10908	91.297	13.711	1	20.28	355199
2001	16818	15849	3.02	2.26	1.42	632.24	12227	93.896	14.002	1.024	15.73	351411
2002	16191	15691	3.1	2.4	1.5	640.54	10908	97.077	14.342	1.0419	16.66	359335
2003	16853	17270	3.02	2.46	1.66	647.75	10174	100.4	14.502	1.064	19.06	355582
2004	18200	18373	3.26	2.77	2.29	656.83	10296	104.36	13.999	1.0946	24.01	332465
2005	18029	16903	3.71	3.19	3.08	663.25	10103	108.4	14.12	1.13	31.65	315420
2006	20616	18544	4.29	2.98	3.64	670.05	11269	112.27	14.384	1.1657	37.06	270486
2007	19843	18756	5.31	4.63	3.44	668.74	10815	115.5	13.408	1.1966	41.01	263595
2008	21440	18717.5	5.21	4.73	3.88	671.31	11640	118	13	1.225	55.44	249874

Table F2

Data: Equations for the number of residential and commercial customers in Alaska

Author: Tony Radich, EIA, June, 2007 and Margaret Leddy, July 2009.

Source: *Natural Gas Annual* (1985-2000), DOE/EIA-0131, see Table F1.

Derivation:

a. Residential customers

Since 1967, the number of residential households has increased steadily, mirroring the population growth in Alaska. Because the current year's population is highly dependent on the previous year's value, the number of residential consumers was estimated based on its lag values. The forecast equation is determined as follows:

$$NRS_t = \beta_0 + \beta_{-1} * NRS_{t-1} + \beta_{-2} * NRS_{t-2} + \beta_1 * POP$$

where,

NRS = natural log of thousands of Alaska residential gas customers (AK_RN in code)
POP = natural log of Alaska population in thousands (AK_POP in code, Appendix E)
t = year

Regression Diagnostics and Parameters Estimates:

Dependent Variable: NRS
Method: Least Squares
Date: 07/03/07
Sample (adjusted): 1969-2005
Included observations: 37 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
C	-2.677338	0.946058	-2.829994	0.0079	β_0
NRS(-1)	0.887724	0.166407	5.334659	0.0000	β_{-1}
NRS(-2)	-0.184504	0.141213	-1.306569	0.2004	β_{-2}
POP	0.626436	0.201686	3.105990	0.0039	β_1

R-squared	0.995802	Mean dependent var	3.950822
Adjusted R-squared	0.995421	S.D. dependent var	0.602330
S.E. of regression	0.040760	Akaike info criterion	-3.460402
Sum squared resid	0.054827	Schwarz criterion	-3.286248
Log likelihood	68.01743	F-statistic	2609.424
Durbin-Watson stat	1.656152	Prob(F-statistic)	0.000000

This translates into the following forecast equation in the code:

$$AK\_RN_t = \exp[-2.677 + (0.888*\log(AK\_RN_{t-1})) - (0.185*\log(AK\_RN_{t-2})) + (0.626*\log(AK\_POP_t))]$$

b. Commercial customers

The number of commercial consumers, based on billing units, also showed a strong relationship to its lag value. The forecast equation was determined using data from 1985 to 2008 as follows:

$$COM\_CUST_t = \beta 0 + \beta_{-1} * COM\_CUST_{t-1}$$

where,

COM_CUST = number of Alaska commercial gas customers in year t, in thousands(AK_CM in the code)

t = year

Regression Diagnostics and Parameters Estimates:

Dependent Variable: COM_CUST
Method: Least Squares
07/14/09
Sample (adjusted): 1974-2008
Included observations: 35 after adjustments
Newey-West HAC Standard Errors & Covariance (lag truncation=3)

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
C	0.932946	0.294368	3.169323	0.0033	β_0
COM_CUST(-1)	0.937471	0.023830	39.33956	0.0000	β_{-1}

R-squared	0.982050	Mean dependent var	10.63666
Adjusted R-squared	0.981506	S.D. dependent var	3.534514
S.E. of regression	0.480669	Akaike info criterion	1.428171
Sum squared resid	7.624424	Schwarz criterion	1.517048
Log likelihood	-22.99300	Hannan-Quinn criter.	1.458852
F-statistic	1805.422	Durbin-Watson	1.859586
Prob(F-statistic)	0.000000		

This translates into the following forecast equation in the code:

$$AK\_CN_t = 0.932946 + (0.937471 * AK\_CN_{t-1})$$

Table F3

Data: Coefficients for the following Pipeline Tariff Submodule forecasting equations for pipeline and storage: total cash working capital for the combined existing and new capacity; depreciation, depletion, and amortization expenses for existing capacity; accumulated deferred income taxes for the combined existing and new capacity; and total operating and maintenance expense for the combined existing and new capacity.

Author: Science Applications International Corporation (SAIC)

Source: Foster Pipeline Financial Data, 1997-2006
Foster Storage Financial Data, 1990-1998

Variables:

For Transportation:

R_CWC	=	total pipeline transmission cash working capital for existing and new capacity (2005 real dollars)
DDA_E	=	annual depreciation, depletion, and amortization costs for existing capacity (nominal dollars)
NPIS_E	=	net plant in service for existing capacity in dollars (nominal dollars)
NEWCAP_E	=	change in existing gross plant in service (nominal dollars) between t and t-1 (set to zero during the forecast year phase since $GPIS\_E_{a,t}$ = $GPIS\_E_{a,t+1}$ for year t >= 2007)
ADIT	=	accumulated deferred income taxes (nominal dollars)
NEWCAP	=	change in gross plant in service between t and t-1 (nominal dollars)
R_TOM	=	total operating and maintenance cost for existing and new capacity (2005 real dollars)
GPIS	=	capital cost of plant in service for existing and new capacity (nominal dollars)
DEPSHR	=	level of the accumulated depreciation of the plant relative to the gross plant in service for existing and new capacity at the beginning of year t. This variable is a proxy for the age of the capital stock.
TECHYEAR	=	MODYEAR (time trend in Julian units, the minimum value of this variable in the sample being 1997, otherwise TECHYEAR=0 if less than 1997)
a	=	arc
t	=	forecast year

For Storage:

R_STCWC	=	total cash working capital at the beginning of year t for existing and new capacity (1996 real dollars)
DSTTCAP	=	total gas storage capacity (Bcf)
STDDA_E	=	annual depreciation, depletion, and amortization costs for existing capacity (nominal dollars)

STNPIS_E = net plant in service for existing capacity (nominal dollars)
STNEWCAP = change in gross plant in service for existing capacity (nominal dollars)
STADIT = accumulated deferred income taxes (nominal dollars)
NEWCAP = change in gross plant in service for the combined existing and new capacity between years t and t-1 (nominal dollars)
R_STTOM = total operating and maintenance cost for existing and new capacity (1996 real dollars)
DSTWCAP = level of gas working capacity for region r during year t (Bcf)
r = NGTDM region
t = forecast year

References: For transportation: "Memorandum describing the estimated and forecast equations for TOM, DDA, CWC, and ADIT for the new PTM," by SAIC, June 23-July 22, 2008.
For storage: "Memorandum describing the estimated and forecast equations for TOM, DDA, CWC, and ADIT for the new PTM," by SAIC, May 31, 2000.

Derivation: Estimations were done by using an accounting algorithm in combination with estimation software. Projections are based on a series of econometric equations which have been estimated using the Time Series Package (TSP) software. Equations were estimated by arc for pipelines and by NGTDM region for storage, as follows: total cash working capital for the combined existing and new capacity; depreciation, depletion, and amortization expenses for existing capacity; accumulated deferred income taxes for the combined existing and new capacity; and total operating and maintenance expense for the combined existing and new capacity. These equations are defined as follows:

(1) Total Cash Working Capital for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model.

Because of economies in cash management, a log-linear specification between total operating and maintenance expenses, R_TOM_a, and the level of cash working capital, R_CWC_a was assumed. To control for arc specific effects, a binary variable was created for each of the arcs. The associated coefficient represents the arc specific constant term.

The underlying notion of this equation is the working capital represents funds to maintain the capital stock and is therefore driven by changes in R_TOM

The forecasting equation is presented in two stages.

Stage 1:

$$\mathrm{Ln}(R\_CWC_{a,t}) = CWC\_C_a * (1-\rho) + CWC\_TOM * \mathrm{Ln}(R\_TOM_{a,t}) + \rho * \mathrm{Ln}(R\_CWC_{a,t-1}) - \rho * CWC\_TOM * \mathrm{Ln}(R\_TOM_{a,t-1})$$

Stage 2:

$$R\_CWC_{a,t} = CWC\_K * \exp(\mathrm{Ln}(R\_CWC_{a,t}))$$

where,

R_CWC	=	total pipeline transmission cash working capital for existing and new capacity (2005 real dollars)
CWC_C_a	=	estimated arc specific constant for gas transported from node to node (see Table F3.2)
CWC_TOM	=	estimated R_TOM coefficient (see Table F3.2)
R_TOM	=	total operation and maintenance expenses in 2005 real dollars
CWC_K	=	correction factor estimated in stage 2 of the regression equation estimation process
ρ	=	autocorrelation coefficient from estimation (see Table F3.2 -- CWC_RHO)

Ln is a natural logarithm operator and CWC_K is the correction factor estimated in equation two.

The results of this regression are reported below:

Dependent variable: R_CWC
Number of observations: 396

Mean of dep. var.	= 18503.0	LM het. Test	= 135.638 [.000]
Std. dev. of dep. var.	= 283454.4	Durbin-Watson	= 2.29318 [<1.00]
Sum of squared residuals	= .116124E+11	Jarque-Bera test	= 6902.15 [.000]
Variance of residuals	= .293986E+08	Ramsey's RESET2	= .849453 [.357]
Std. error of regression	= 5422.05	Schwarz B.I.C.	= 3969.29
R-squared	= .963435	Log likelihood	= -3966.30
Adjusted R-squared	= .963435		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
CWC_K	1.01813	8.31E-03	122.551	[.000]

For Storage:

$$R\_STCWC_{r,t} = e^{(\beta_{0,r} * (1-\rho))} * DSTTCAP_{r,t-1}^{\beta_1} * R\_STCWC_{r,t-1}^{\rho} * DSTTCAP_{r,t-2}^{-\rho * \beta_1}$$

where,

$\beta_{0,a}$	=	constant term estimated by region (see Table F3.1, $\beta_{0,r} = REG_r$)
	=	STCWC_CREG (Appendix E)

β_1 = 1.07386
= STCWC_TOTCAP (Appendix E)
t-statistic = (2.8)
ρ = 0.668332
= STCWC_RHO (Appendix E)
t-statistic = (6.8)
DW = 1.53
R-Squared = 0.99

(2) Total Depreciation, Depletion, and Amortization for Existing Capacity

(a) existing capacity (up to 2000 for pipeline and up to 1998 for storage)

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. A linear specification was chosen given that DDA_E is generally believed to be proportional to the level of net plant. The forecasting equation was estimated with a correction for first order serial correlation.

$$DDA\_E_{a,t} = DDA\_C_a * ARC_a + DDA\_NPIS * NPIS_{a,t-1} + DDA\_NEWCAP * NEWCAP\_E_{a,t}$$

where,

DDA_C_a = constant term estimated by arc for the binary variable ARC_a (see Table F3.3, $DDA\_C_a = B\_ARC_{xx\_yy}$)
ARC_a = binary variable created for each arc to control for arc specific effects
DDA_NPIS = estimated coefficient (see Table F3.3)
DDA_NEWCAP = estimated coefficient (see Table F3.3)

The standard errors in Table F3.3 are computed from heteroscedastic-consistent matrix (Robust-White). The results of this regression are reported below:

Dependent variable: DDA_E
Number of observations: 446

Mean of dep. var.	= 25154.4	R-squared	= .995361
Std. dev. of dep. var.	= 33518.3	Adjusted R-squared	= .994761
Sum of squared residuals	= .231907E+10	LM het. Test	= 30.7086 [.000]
Variance of residuals	= .588597E+07	Durbin-Watson	= 2.06651 [<1.00]
Std. error of regression	= 2426.10		

For Storage:

$$STDDA\_E_{r,t} = \beta_{0,r} + \beta_1 * STNPIS\_E_{r,t-1} + \beta_2 * STNEWCAP_{r,t}$$

where,

$\beta_{0,a}$ = constant term estimated by region (see Table F3.4, $\beta_{0,r} = REG_r$)
= STDDA_CREG (Appendix E)
β_1, β_2 = (0.032004, 0.028197)
= STDDA_NPIS, STDDA_NEWCAP (Appendix E)
t-statistic = (10.3) (16.9)
DW = 1.62
R-Squared = 0.97

(b) new capacity (generic pipelines and storage)

A regression equation is not used for the new capacity; instead, an accounting algorithm is used (presented in Chapter 6).

(3) Accumulated Deferred Income Taxes for the Combined Existing and New Capacity

<u>*For Transportation:*</u>

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. To control for arc specific effects, a binary variable ARC_a was created for each of the arcs. The associated coefficient represents the arc specific constant term.

Because the level of deferred income taxes is a stock (and not a flow) it was hypothesized that a formulation that focused on the change in the level of accumulated deferred income taxes from the previous year, $deltaADIT_{a,t}$, would be appropriate. Specifically, a linear relationship between the change in ADIT and the change in the level of gross plant in service, $NEWCAP_{a,t}$, and the change in tax policy, POLICY_CHG, was assumed. The form of the estimating equation is:

$$\text{delta}\,ADIT_{a,t} = ADIT\_C_a * ARC_a + \beta_1 * NEWCAP_{a,t} + \beta_2 * NEWCAP_{a,t} + \beta_3 * NEWCAP_{a,t}$$

where,

$ADIT\_C_a$ = constant term estimated by arc for the binary variable ARC_a (see Table F3.5, $ADIT\_C_a = B\_ARC_{xx\_yy}$)
β_1 = BNEWCAP_PRE2003, estimated coefficient on the change in gross plant in service in the pre-2003 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
β_2 = BNEWCAP_2003_2004, estimated coefficient on the change in gross plant in service for the years 2003 and 2004 because of changes in tax policy (Appendix F, Table F3.5). It is zero otherwise.
β_3 = BNEWCAP_POST2004, estimated coefficient on the change in gross plant in service in the post-2004 period because of changes in tax policy (Appendix F, Table F3.5). It is zero otherwise.

The estimation results are:

Dependent variable: DELTAADIT
Number of observations: 396

Mean of dep. var.	= 6493.50	R-squared	= .464802
Std. dev. of dep. var.	= 17140.8	Adjusted R-squared	= .383664
Sum of squared residuals	= .621120E+11	LM het. test	= 4.03824 [.044]
Variance of residuals	= .181084E+09	Durbin-Watson	= 2.44866 [<1.00]
Std. error of regression	= 13456.8		

For Storage:

$$STADIT_{r,t} = \beta_0 + \beta_1 * STADIT_{r,t-1} + \beta_2 * NEWCAP_{r,t}$$

where,

β_0	=	-212.535
	=	STADIT_C (Appendix E)
β_1, β_2	=	(0.921962, 0.212610)
	=	STADIT_ADIT, STADIT_NEWCAP (Appendix E)
t-statistic	=	(58.8) (8.4)
DW	=	1.69
R-Squared	=	0.98

(4) Total Operating and Maintenance Expense for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. To control for arc specific effects, a binary variable ARC_a was created for each of the arcs. The associated coefficient represents the arc specific constant term.

The forecasting equation is presented in two stages.

Stage 1:

$$\begin{aligned} Ln(R\_TOM_{a,t}) = & TOM\_C_a * ARC_a * (1-\rho) + TOM\_GPIS1 * Ln(GPIS_{a,t-1}) \\ & + TOM\_DEPSHR * DEPSHR_{a,t-1} + TOM\_BYEAR * 2006 \\ & + TOM\_BYEAR\_EIA * (TECHYEAR - 2006.0) + \rho * Ln(R\_TOM_{a,t-1}) \\ & - \rho * (TOM\_GPIS1 * Ln(GPIS_{a,t-2}) + TOM\_DESHR * DEPSHR_{a,t-2} \\ & + TOM\_BYEAR * 2006 + TOM\_BYEAR\_EIA * (TECHYEAR - 1 - 2006.0)) \end{aligned}$$

Stage 2:

$$R\_TOM_{a,t} = TOM\_K * \exp(Ln(R\_TOM_{a,t}))$$

where Ln is a natural logarithm operator and TOM_K is the correction factor estimated in equation two, and where,

TOM_C_a	=	constant term estimated by arc for the binary variable ARCa (see Table F3.6, TOM_Ca = B_ARCxx_yy)
ARC_a	=	binary variable created for each arc to control for arc specific effects
TOM_GPIS1	=	estimated coefficient (see Table F3.6)
TOM_DEPSHR	=	estimated coefficient (see Table F3.6)
TOM_BYEAR	=	estimated coefficient (see Table F3.6)
TOM_BYEAR_EIA	=	future rate of decline in R_TOM due to technology improvements and efficiency gains. EIA assumes that this rate is the same as TOM_BYEAR (see Table F3.6)
ρ	=	first-order autocorrelation, TOM_RHO (see Table F3.6)

The results of this regression are reported below:

Dependent variable: R_TOM
Number of observations: 396

Mean of dep. var.	= 52822.9	LM het. test	= 28.7074 [.000]
Std. dev. of dep. var.	= 76354.9	Durbin-Watson	= 2.01148 [<1.00]
Sum of squared residuals	= .668483E+11	Jarque-Bera test	= 13559.1 [.000]
Variance of residuals	= .169236E+09	Ramsey's RESET2	= 4.03086 [.045]
Std. error of regression	= 13009.1	Schwarz B.I.C.	= 4215.86
R-squared	= .971019	Log likelihood	= -4312.87
Adjusted R-squared	= .971019		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
TOM_K	0.940181	6.691E-03	140.504	[.000]

For Storage:

$$R\_STTOM_{r,t} = e^{(\beta_0 * (1-\rho))} * DSTWCAP_{r,t-1}^{\beta_1} * R\_STTOM_{r,t-1}^{\rho} * DSTWCAP_{r,t-2}^{-\rho * \beta_1}$$

where,

β_0	=	-6.6702
	=	STTOM_C (Appendix E)
β_1	=	1.44442
	=	STTOM_WORCAP (Appendix E)
t-statistic	=	(33.6)
ρ	=	0.761238
	=	STTOM_RHO (Appendix E)
t-statistic	=	(10.2)
DW	=	1.39
R-Squared	=	0.99

Table F3.1. Summary Statistics for Storage Total Cash Working Capital Equation

Variable	Coefficient	Standard Error	t-statistic
REG2	-2.30334	5.25413	-.438386
REG3	-1.51115	5.33882	-.283049
REG4	-2.11195	5.19899	-.406224
REG5	-2.07950	5.06766	-.410346
REG6	-1.24091	4.97239	-.249559
REG7	-1.63716	5.27950	-.310097
REG8	-2.48339	4.68793	-.529740
REG9	-3.23625	4.09158	-.790954
REG11	-2.15877	4.33364	-.498143

Table F3.2. Summary Statistics for Pipeline Total Cash Working Capital Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
CWC_TOM	0.381679	.062976	6.06073	[.000]
B_ARC01_01	4.83845	.644360	7.50892	[.000]
B_ARC02_01	5.19554	.644074	8.06668	[.000]
B_ARC02_02	6.37816	.781655	8.15982	[.000]
B_ARC02_03	4.38403	.594344	7.37625	[.000]
B_ARC02_05	5.02364	.684640	7.33764	[.000]
B_ARC03_02	5.51162	.651682	8.45754	[.000]
B_ARC03_03	6.10201	.772378	7.90028	[.000]
B_ARC03_04	4.10475	.572836	7.16566	[.000]
B_ARC03_05	4.69978	.665214	7.06507	[.000]
B_ARC03_15	4.99465	.600910	8.31180	[.000]
B_ARC04_03	5.56047	.718330	7.74083	[.000]
B_ARC04_04	6.15095	.783539	7.85021	[.000]
B_ARC04_07	4.26747	.590736	7.22400	[.000]
B_ARC04_08	4.12216	.611516	6.74089	[.000]
B_ARC05_02	5.50272	.732227	7.51505	[.000]
B_ARC05_03	4.93360	.667589	7.39018	[.000]
B_ARC05_05	6.03791	.774677	7.79409	[.000]
B_ARC05_06	3.27334	.516303	6.33995	[.000]
B_ARC06_03	5.80098	.714338	8.12078	[.000]
B_ARC06_05	5.76939	.741907	7.77644	[.000]
B_ARC06_06	6.73455	.807246	8.34262	[.000]
B_ARC06_07	3.52000	.555549	6.33606	[.000]
B_ARC06_10	4.64811	.665947	6.97970	[.000]
B_ARC07_04	5.60946	.732039	7.66279	[.000]
B_ARC07_06	6.35683	.778573	8.16471	[.000]
B_ARC07_07	6.81298	.828208	8.22616	[.000]
B_ARC07_08	3.60827	.543296	6.64144	[.000]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC07_11	5.89640	.708385	8.32373	[.000]
B_ARC07_21	4.85140	.621031	7.81185	[.000]
B_ARC08_04	4.94307	.678799	7.28208	[.000]
B_ARC08_07	3.97367	.579267	6.85982	[.000]
B_ARC08_08	5.58162	.723678	7.71286	[.000]
B_ARC08_09	5.19274	.635784	8.16746	[.000]
B_ARC08_11	5.12277	.637835	8.03148	[.000]
B_ARC08_12	4.29097	.593945	7.22452	[.000]
B_ARC09_08	4.10222	.576694	7.11333	[.000]
B_ARC09_09	5.44178	.684020	7.95558	[.000]
B_ARC09_12	4.96229	.600227	8.26735	[.000]
B_ARC09_20	2.63716	.448339	5.88207	[.000]
B_ARC11_07	5.58226	.687702	8.11726	[.000]
B_ARC11_08	4.36952	.548152	7.97137	[.000]
B_ARC11_11	6.13044	.728452	8.41571	[.000]
B_ARC11_12	5.93253	.710336	8.35173	[.000]
B_ARC11_22	4.33062	.545420	7.93998	[.000]
B_ARC15_02	5.09861	.583090	8.74412	[.000]
B_ARC16_04	5.03673	.592859	8.49567	[.000]
B_ARC17_04	4.17798	.576943	7.24158	[.000]
B_ARC19_09	5.14500	.618100	8.32389	[.000]
B_ARC20_09	4.58498	.624006	7.34766	[.000]
B_ARC21_07	4.26846	.563536	7.57441	[.000]
CWC_RHO	0.527389	.048379	10.9011	[.000]

Table F3.3. Summary Statistics for Pipeline Depreciation, Depletion, and Amortization Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
DDA_NEWCAP	.725948E-02	.200846E-02	3.61446	[.000]
DDA_NPIS	.023390	.103991E-02	22.4923	[.000]
B_ARC01_01	4699.58	862.825	5.44674	[.000]
B_ARC02_01	5081.37	853.478	5.95372	[.000]
B_ARC02_02	43769.1	1954.50	22.3940	[.000]
B_ARC02_03	2050.29	814.056	2.51861	[.012]
B_ARC02_05	7876.12	880.047	8.94965	[.000]
B_ARC03_02	5973.21	842.863	7.08681	[.000]
B_ARC03_03	33063.3	1489.77	22.1936	[.000]
B_ARC03_04	1032.74	809.439	1.27588	[.202]
B_ARC03_05	2386.89	845.864	2.82184	[.005]
B_ARC03_15	7652.92	864.810	8.84924	[.000]
B_ARC04_03	19729.5	1118.66	17.6368	[.000]
B_ARC04_04	35522.7	2267.45	15.6663	[.000]
B_ARC04_07	1919.97	811.222	2.36677	[.018]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC04_08	747.069	822.607	.908172	[.364]
B_ARC05_02	15678.2	1114.41	14.0686	[.000]
B_ARC05_03	6452.49	855.092	7.54596	[.000]
B_ARC05_05	45000.5	1771.82	25.3979	[.000]
B_ARC05_06	446.742	809.035	.552191	[.581]
B_ARC06_03	11967.8	942.879	12.6928	[.000]
B_ARC06_05	22576.3	1243.19	18.1599	[.000]
B_ARC06_06	67252.9	2892.23	23.2530	[.000]
B_ARC06_07	1134.14	809.115	1.40170	[.161]
B_ARC06_10	15821.4	989.531	15.9888	[.000]
B_ARC07_04	15041.4	984.735	15.2746	[.000]
B_ARC07_06	48087.6	1908.12	25.2015	[.000]
B_ARC07_07	80361.2	3384.54	23.7436	[.000]
B_ARC07_08	833.829	809.565	1.02997	[.303]
B_ARC07_11	4732.17	928.814	5.09486	[.000]
B_ARC07_21	1452.16	922.486	1.57418	[.115]
B_ARC08_04	4920.06	1022.86	4.81008	[.000]
B_ARC08_07	1425.79	811.348	1.75731	[.079]
B_ARC08_08	34661.3	1694.49	20.4553	[.000]
B_ARC08_09	5962.90	873.649	6.82528	[.000]
B_ARC08_11	1088.95	824.202	1.32122	[.186]
B_ARC08_12	7610.79	899.215	8.46382	[.000]
B_ARC09_08	2857.54	814.127	3.50994	[.000]
B_ARC09_09	15070.9	1021.78	14.7496	[.000]
B_ARC09_12	3120.00	833.569	3.74295	[.000]
B_ARC09_20	279.322	917.025	.304595	[.761]
B_ARC11_07	4022.68	871.680	4.61485	[.000]
B_ARC11_08	325.210	809.288	.401846	[.688]
B_ARC11_11	5616.89	1025.31	5.47822	[.000]
B_ARC11_12	4041.93	940.189	4.29906	[.000]
B_ARC11_22	259.293	809.060	.320487	[.749]
B_ARC15_02	2125.53	812.198	2.61701	[.009]
B_ARC16_04	8017.53	871.030	9.20465	[.000]
B_ARC17_04	3316.38	860.323	3.85481	[.000]
B_ARC19_09	4216.02	853.774	4.93810	[.000]
B_ARC20_09	6238.31	834.249	7.47776	[.000]
B_ARC21_07	666.813	810.034	.823192	[.410]

Table F3.4. Summary Statistics for Storage Depreciation, Depletion, and Amortization Equation

Variable	Coefficient	St-Error	t-statistic
REG2	4485.56	1204.28	3.72467
REG3	6267.52	1806.17	3.47006
REG4	3552.55	728.230	4.87833
REG5	2075.31	646.561	3.20976
REG6	1560.07	383.150	4.07169
REG7	4522.42	1268.87	3.56412
REG8	1102.49	622.420	1.77129
REG9	65.2731	10.1903	6.40542
REG11	134.692	494.392	.272439

Table F3.5. Summary Statistics for Pipeline Accumulated Deferred Income Tax Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
BNEWCAP_PRE2003	.067242	.023235	2.89405	[.004]
BNEWCAP_2003_2004	.132014	.013088	10.0865	[.000]
BNEWCAP_POST2004	.109336	.028196	3.87766	[.000]
B_ARC01_01	3529.80	4775.58	.739134	[.460]
B_ARC02_01	2793.71	4766.40	.586125	[.558]
B_ARC02_02	15255.3	5318.30	2.86844	[.004]
B_ARC02_03	767.648	4758.23	.161331	[.872]
B_ARC02_05	2479.86	4768.91	.520005	[.603]
B_ARC03_02	1663.09	4761.98	.349243	[.727]
B_ARC03_03	6184.51	4966.65	1.24521	[.213]
B_ARC03_04	-14.6495	4757.75	-.307908E-02	[.998]
B_ARC03_05	3183.89	4761.49	.668676	[.504]
B_ARC03_15	2531.19	4759.07	.531866	[.595]
B_ARC04_03	3660.65	4780.00	.765826	[.444]
B_ARC04_04	6076.87	4900.20	1.24013	[.215]
B_ARC04_07	-391.339	4757.90	-.082250	[.934]
B_ARC04_08	1798.04	4758.19	.377884	[.706]
B_ARC05_02	6654.17	4801.91	1.38573	[.166]
B_ARC05_03	1842.90	4762.25	.386982	[.699]
B_ARC05_05	6344.87	5220.98	1.21526	[.224]
B_ARC05_06	148.421	4757.73	.031196	[.975]
B_ARC06_03	2475.65	4775.18	.518441	[.604]
B_ARC06_05	5193.49	4996.38	1.03945	[.299]
B_ARC06_06	24991.1	5803.11	4.30650	[.000]
B_ARC06_07	-259.276	4757.72	-.054496	[.957]
B_ARC06_10	13015.7	4862.80	2.67659	[.007]
B_ARC07_04	189.221	4776.34	.039616	[.968]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC07_06	14166.3	5012.13	2.82640	[.005]
B_ARC07_07	16102.7	5680.52	2.83472	[.005]
B_ARC07_08	118.047	4758.11	.024810	[.980]
B_ARC07_11	-434.842	4808.84	-.090426	[.928]
B_ARC07_21	495.934	5498.36	.090197	[.928]
B_ARC08_04	4679.95	4780.56	.978955	[.328]
B_ARC08_07	365.793	4762.84	.076801	[.939]
B_ARC08_08	5133.64	5235.92	.980466	[.327]
B_ARC08_09	-3672.71	4770.23	-.769923	[.441]
B_ARC08_11	-1856.45	4762.76	-.389784	[.697]
B_ARC08_12	795.831	4808.51	.165505	[.869]
B_ARC09_08	537.433	4759.95	.112907	[.910]
B_ARC09_09	-1812.27	4829.76	-.375230	[.707]
B_ARC09_12	-2803.40	4761.86	-.588719	[.556]
B_ARC09_20	55.5366	5493.73	.010109	[.992]
B_ARC11_07	-1137.92	4772.21	-.238448	[.812]
B_ARC11_08	276.612	4757.86	.058138	[.954]
B_ARC11_11	7.99239	4874.89	.163950E-02	[.999]
B_ARC11_12	-1079.76	4825.77	-.223750	[.823]
B_ARC11_22	337.987	4759.18	.071018	[.943]
B_ARC15_02	429.875	4758.19	.090344	[.928]
B_ARC16_04	2744.23	4759.07	.576631	[.564]
B_ARC17_04	935.795	4757.97	.196680	[.844]
B_ARC19_09	-3806.27	4762.95	-.799141	[.424]
B_ARC20_09	1173.22	4768.48	.246037	[.806]
B_ARC21_07	586.673	4759.84	.123255	[.902]

Table F3.6. Summary Statistics for Pipeline Total Operating and Maintenance Expense Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
TOM_GPIS1	.256869	.114518	2.24304	[.025]
TOM_DEPSHR	1.69807	.429440	3.95415	[.000]
TOM_BYEAR	-.019974	.718590E-02	-2.77955	[.005]
B_ARC01_01	45.8116	13.5505	3.38081	[.001]
B_ARC02_01	45.7428	13.5502	3.37580	[.001]
B_ARC02_02	47.4313	13.4380	3.52963	[.000]
B_ARC02_03	45.3570	13.6230	3.32944	[.001]
B_ARC02_05	46.3936	13.5393	3.42658	[.001]
B_ARC03_02	45.8277	13.5539	3.38115	[.001]
B_ARC03_03	47.1662	13.4461	3.50779	[.000]
B_ARC03_04	44.5365	13.6401	3.26512	[.001]
B_ARC03_05	45.9318	13.5464	3.39071	[.001]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC03_15	45.1262	13.5508	3.33015	[.001]
B_ARC04_03	46.5137	13.4799	3.45060	[.001]
B_ARC04_04	47.4725	13.4290	3.53508	[.000]
B_ARC04_07	45.0325	13.6249	3.30516	[.001]
B_ARC04_08	45.6096	13.5965	3.35451	[.001]
B_ARC05_02	46.8361	13.4859	3.47298	[.001]
B_ARC05_03	46.2316	13.5556	3.41052	[.001]
B_ARC05_05	47.2881	13.4422	3.51788	[.000]
B_ARC05_06	44.2555	13.6969	3.23105	[.001]
B_ARC06_03	46.4249	13.4976	3.43948	[.001]
B_ARC06_05	46.9210	13.4730	3.48260	[.000]
B_ARC06_06	47.6072	13.4045	3.55157	[.000]
B_ARC06_07	44.5090	13.6696	3.25606	[.001]
B_ARC06_10	46.0547	13.5171	3.40715	[.001]
B_ARC07_04	46.6884	13.4905	3.46084	[.001]
B_ARC07_06	47.2664	13.4316	3.51904	[.000]
B_ARC07_07	47.8651	13.3928	3.57395	[.000]
B_ARC07_08	44.7096	13.6750	3.26944	[.001]
B_ARC07_11	46.7847	13.5263	3.45880	[.001]
B_ARC07_21	45.4067	13.6138	3.33535	[.001]
B_ARC08_04	46.3290	13.5124	3.42864	[.001]
B_ARC08_07	45.1349	13.6437	3.30810	[.001]
B_ARC08_08	46.8373	13.4658	3.47825	[.001]
B_ARC08_09	45.7056	13.5495	3.37323	[.001]
B_ARC08_11	45.9766	13.5925	3.38250	[.001]
B_ARC08_12	45.1596	13.5537	3.33190	[.001]
B_ARC09_08	44.9927	13.6211	3.30317	[.001]
B_ARC09_09	46.2997	13.5103	3.42699	[.001]
B_ARC09_12	45.2655	13.5793	3.33342	[.001]
B_ARC09_20	43.2644	13.7686	3.14226	[.002]
B_ARC11_07	46.4472	13.5409	3.43015	[.001]
B_ARC11_08	44.9105	13.6898	3.28058	[.001]
B_ARC11_11	47.0985	13.5107	3.48603	[.000]
B_ARC11_12	46.8744	13.5270	3.46526	[.001]
B_ARC11_22	44.8071	13.7118	3.26778	[.001]
B_ARC15_02	44.8267	13.6116	3.29327	[.001]
B_ARC16_04	45.0068	13.5491	3.32175	[.001]
B_ARC17_04	44.8832	13.5582	3.31042	[.001]
B_ARC19_09	45.4861	13.5613	3.35412	[.001]
B_ARC20_09	45.5729	13.5745	3.35725	[.001]
B_ARC21_07	44.6298	13.6465	3.27041	[.001]
TOM_RHO	.297716	.052442	5.67707	[.000]

Table F4

Data: Equation for industrial distribution tariffs

Author: Ernest Zampelli, SAIC, 2009.

Source: The source for the peak and off-peak consumption data used in this estimation was the Natural Gas Monthly, DOE/EIA-0130. State level city gate prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM regions) prices. The quantity-weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. Prices for the estimations were derived as described in Table F5.

Variables:

$TIN_{r,n,t}$ = industrial distributor tariff in region r, network n (1987 dollars per Mcf) [DTAR_SF$_3$]
$PREG_r$ = 1, if observation is in region r during peak period (n=1), =0 otherwise
$QIND_{r,t}$ = industrial gas consumption in region r in year t (MMcf) [BASQTY_SF$_3$+BASQTY_SI$_3$]
r = NGTDM region
t = year
α_0, α_r, $\alpha_{r,n}$ = estimated parameters for regional constants [PINREG15$_r$ and PINREGPK15$_{r,n}$]
β = estimated parameter for consumption
ρ = autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The industrial distributor tariff equation was estimated using backcasted data for the 12 NGTDM regions over the 1990 to 2008 time period. The equation was estimated in linear form with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 5.0. The form of the estimating equation follows:

$$\ln TIN_{r,n,t} = \alpha_0 + \sum_r (\alpha_r + \alpha_{r,pk}) * REG_{r,pk} + \beta * QIND_{r,t} + \rho * TIN_{r,t-1}$$
$$- \rho * (\sum_r (\alpha_r + \alpha_{r,pk}) * REG_{r,pk} + \beta * QIND_{r,t-1})$$

Regression Diagnostics and Parameter Estimates:

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

Dependent variable: TIN87
Number of observations: 456

Mean of dep. var.	=	.282327	R-squared	=	.711027
Std. dev. of dep. var.	=	1.68053	Adjusted R-squared	=	.703199
Sum of squared residuals	=	371.429	Durbin-Watson	=	1.96827

Variance of residuals	=	.838440	Schwarz B.I.C.	=	640.302
Std. error of regression	=	.915663	Log likelihood	=	-600.506

Parameter	Estimate	Standard Error	t-statistic	P-value	Code Variable
WT	.199135	.041539	4.79396	[.000]	
NE	.664368	.178794	3.71584	[.000]	$PINREG15_1$
WNCNTL	-.565428	.069519	-8.13339	[.000]	$PINREG15_4$
ESCNTL	-.248102	.053509	-4.63666	[.000]	$PINREG15_6$
AZNM	.395943	.093005	4.25725	[.000]	$PINREG15_{11}$
CA	.605914	.097865	6.19132	[.000]	$PINREG15_{12}$
MIDATL_PK	.418090	.101754	4.10881	[.000]	$PINREGPK15_2$
WNCNTL_PK	.354066	.079415	4.45840	[.000]	$PINREGPK15_4$
ESCNTL_PK	.203711	.074239	2.74398	[.006]	$PINREGPK15_6$
WSCNTL_PK	-.411782	.068533	-6.00852	[.000]	$PINREGPK15_7$
WAOR_PK	.263996	.092401	2.85709	[.004]	$PINREGPK15_9$
QIND	-.317443E-03	.482650E-04	-6.57708	[.000]	
RHO	.423561	.043665	9.70021	[.000]	

Standard Errors computed from analytic second derivatives (Newton)

Data used for estimation

		New Engl.	Mid Atl.	E.N. Central	W.N. Central	S.Atl Fl	E.S. Central	W.S. Central	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
		1	2	3	4	5	6	7	8	9	10	11	12
1990 QIN	peak	25.238	156.14	453.96	140.9	185.23	152.15	948.57	56.599	46.146	30.06	13.198	177.12
1990 QIN	off-peak	56.095	270.87	730.76	245.05	351.31	272.39	1987.3	93.839	81.168	54.881	24.473	388.08
1991 QIN	peak	39.282	168.91	481.69	149.95	171.26	158.54	979.32	66.408	47.282	30.235	14.3	201.54
1991 QIN	off-peak	82.376	282.18	729.31	254.99	330.64	288.33	2003.6	109.22	87.502	53.163	24.25	401.08
1992 QIN	peak	54.227	204.09	498.51	155.99	185.1	166.54	1018.4	74.334	49.691	29.904	13.778	217.12
1992 QIN	off-peak	108.78	354.7	777.87	263.94	353.2	304.97	1942.1	128.69	88.594	54.925	23.066	377.45
1993 QIN	peak	61.814	224.11	529.31	166.97	185.5	176.42	1045.5	83.593	54.178	34.299	13.167	214.7
1993 QIN	off-peak	123.32	366.69	786.37	283.17	358.16	305.77	2109.2	148.52	98.713	66.051	25.02	445.02
1994 QIN	peak	60.862	243.6	553.36	190.76	182.9	170.14	1088.8	91.076	58.07	42.837	13.711	210.07
1994 QIN	off-peak	111.77	398.1	795.93	320.33	380.72	299.53	2069.5	149.79	112.1	84.036	30.899	446.68
1995 QIN	peak	67.612	274.81	564.08	174.94	198.2	181.21	1094.8	92.348	62.974	49.496	18.42	216.02
1995 QIN	off-peak	117.09	462.71	842.05	302.97	408.65	323.96	2206	154.12	115.93	83.981	30.338	471.9
1996 QIN	peak	54.363	285.51	578.99	166.26	193.94	178.95	1196.9	93.314	66.644	46.056	17.943	231.69
1996 QIN	off-peak	112.99	481.59	876.22	283.25	385.99	324.38	2332	168.08	135.35	90.666	31.894	461.85
1997 QIN	peak	48.405	234.18	527.5	180.9	213.68	185.66	1158.6	77.997	70.675	41.903	18.414	232.69
1997 QIN	off-peak	86.131	402.1	814.07	291.91	398.91	334.13	2246.7	136.03	130.89	83.234	35.325	487.2
1998 QIN	peak	52.54	226.19	506.96	165.78	200.57	186.74	1119.4	94.347	83.184	40.685	18.07	232.48
1998 QIN	off-peak	95.549	375.1	771.51	298.64	370.18	328.87	2140.8	154.17	152.69	81.23	35.135	513.67
1999 QIN	peak	55.157	197.85	523.25	160.89	221.22	201	1023.2	77.398	81.611	43.813	18.686	203.63
1999 QIN	off-peak	100.84	332.74	804.58	274.65	340.85	366.69	2032.3	146.67	150.74	90.394	34.188	522.78
2000 QIN	peak	54.493	152.64	539.34	163.07	194.49	200.21	1080.9	87.687	57.099	35.056	17.259	218.27
2000 QIN	off-peak	86.042	262.25	788.24	285.56	364.74	347.3	2230.3	139.76	102.92	69.631	33.847	558.47
2001 QIN	peak	49.565	139.45	480.99	150.12	155.17	168.54	1051.7	104.16	50.923	30.792	19.007	211.11
2001 QIN	off-peak	85.579	228.74	699.46	258.24	303.54	299.32	1974.5	167.1	93.96	63.919	35.375	455.88
2002 QIN	peak	52.54	144.33	470.45	121.75	173.22	176.85	1011.8	91.637	51.527	28.746	14.516	241.23
2002 QIN	off-peak	81.724	234.44	758.81	221.6	328.78	305.4	2005.8	169.31	86.7	54.823	26.005	499.44
2003 QIN	peak	39.744	139.83	481.39	158.53	175.69	176.28	982.91	89.808	47.009	25.345	13.858	252.4
2003 QIN	off-peak	46.063	215.76	678.89	260.18	298.39	286.67	1906.9	146.28	86.394	47.99	25.8	527.13

		New Engl.	Mid Atl.	E.N. Central	W.N. Central	S.Atl Fl	E.S. Central	W.S. Central	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
		1	2	3	4	5	6	7	8	9	10	11	12
2004 QIN	peak	37.198	136.43	491.51	156.64	176.4	173.92	973.99	91.339	49.641	23.374	16.187	271.43
2004 QIN	off-peak	45.242	214.24	688.46	265.89	305.66	303.33	1907	146.72	89.858	40.229	26.574	564.84
2005 QIN	peak	40.728	135.24	478.91	158.08	172.16	168.5	808.09	93.829	48.327	23.015	14.013	267.71
2005 QIN	off-peak	45.586	205.31	681.74	260.6	290.89	283.02	1538.7	159.82	88.192	40.118	27.785	514.11
2006 QIN	peak	35.807	124.55	429.28	162.89	161.04	157.39	787.35	97.212	50.66	24.302	13.762	244.48
2006 QIN	off-peak	47.391	207.44	673.41	298.82	305.01	292.01	1573.2	151.07	90.187	45.419	22.924	488.02
2007 QIN	peak	39.898	129.41	455.49	173.06	161.02	166.6	834.3	97.509	51.108	23.489	13.67	243.44
2007 QIN	off-peak	47.76	206.79	665.3	304.43	293.52	287.93	1612	156.13	91.117	42.303	23.336	490.16
2008 QIN	peak	41.994	131.75	450.39	195.27	158.12	162.98	834.03	101.53	55.157	25.683	13.962	255.11
2008 QIN	off-peak	45.87	195.97	644.85	323.08	290.82	281.62	1594.9	157.55	89.092	45.653	24.509	509.07
1990 TIN	peak	1.099	0.6688	0.3058	-0.1288	0.7025	0.1655	-0.5898	0.0125	0.6006	0.5055	0.3569	0.7677
1990 TIN	off-peak	0.2422	0.2975	0.3219	-0.2679	0.3332	0.0103	-0.8011	-0.6182	0.3989	0.6069	0.4618	0.4976
1991 TIN	peak	1.1651	0.7854	0.3182	-0.1239	0.6413	0.1569	-0.6598	-0.2375	0.5443	0.4694	0.4572	0.9729
1991 TIN	off-peak	0.2206	0.1636	0.1991	-0.3464	0.1277	-0.0513	-0.6584	-0.7412	0.4784	0.5472	0.3259	0.5807
1992 TIN	peak	1.2819	0.6984	0.2446	-0.0567	0.628	0.1737	-0.6297	-0.1706	0.5218	0.5658	1.2426	1.078
1992 TIN	off-peak	-0.1136	-0.164	-0.0413	-0.3214	0.0843	-0.1326	-0.5803	-0.9941	0.5634	0.4786	0.9993	0.2713
1993 TIN	peak	1.1049	0.5098	0.1875	-0.0766	0.6265	0.1938	-0.5649	-0.1407	0.4983	0.5495	0.7831	0.3072
1993 TIN	off-peak	-0.5318	-0.1649	0.0392	-0.3932	0.0085	-0.1049	-0.4782	-0.5373	0.4175	0.689	0.6653	-0.1804
1994 TIN	peak	1.1511	0.6644	0.3775	0.043	0.5115	0.3493	-0.4724	-0.4511	0.4197	0.0552	0.989	0.4388
1994 TIN	off-peak	-0.7697	0.0425	0.2089	-0.4502	-0.1338	-0.0533	-0.3722	-0.6965	0.1884	0.2237	0.5148	0.1871
1995 TIN	peak	0.9682	0.5415	0.1336	0.0336	0.5657	0.368	-0.5873	-0.1514	0.2735	-0.0042	1.0843	1.3996
1995 TIN	off-peak	-0.6908	0.1533	-0.0909	-0.4184	0.0587	-0.091	-0.5336	-0.1512	0.2563	0.1373	0.8486	0.7801
1996 TIN	peak	1.0885	0.4724	-0.0801	0.1501	0.3852	-0.0597	-0.2293	0.0624	0.3147	0.0629	0.7245	0.7635
1996 TIN	off-peak	-0.5643	-0.1022	-0.0573	-0.4768	0.0265	0.0109	-0.287	0.0885	0.0274	0.2877	0.6701	0.549
1997 TIN	peak	0.9536	0.5591	0.1766	-0.1368	0.4308	0.1911	-0.4936	0.04	0.5014	-0.2748	0.3125	1.0975
1997 TIN	off-peak	-0.3627	-0.9394	-0.1531	-0.7348	-0.0943	-0.0291	-0.2262	0.2046	0.0767	0.1115	0.1918	0.4767
1998 TIN	peak	0.7314	0.029	0.1798	-0.0513	0.1833	0.0944	-0.2879	-0.1103	0.1663	-0.0655	0.544	1.0797
1998 TIN	off-peak	-0.8255	-0.5106	0.0985	-0.5266	-0.3471	-0.2757	-0.1983	0.0953	0.0643	-0.0713	0.176	0.4421
1999 TIN	peak	0.381	0.1165	0.1777	-0.0447	-0.0503	0.1269	-0.4494	0.5426	0.1491	0.6896	0.5158	0.6471
1999 TIN	off-peak	-0.8161	-0.787	-0.2143	-0.5001	-0.4758	-0.2064	-0.2569	0.2023	0.0292	-0.0932	0.0834	0.2283
2000 TIN	peak	0.4368	0.3257	-0.1319	-0.1978	-0.0355	-0.0918	-0.5133	0.3527	0.5765	-0.0681	-0.0613	0.6967
2000 TIN	off-peak	-0.6324	-0.5654	-0.2139	-0.637	-0.4437	-0.2846	-0.3444	0.3139	-0.0557	0.2312	-0.0438	0.5583
2001 TIN	peak	-0.0298	0.5579	0.0726	-0.3949	-0.0079	-0.2461	-0.7083	0.157	-0.2738	-0.3584	-0.0328	-0.4836
2001 TIN	off-peak	-0.1169	0.2263	0.2662	-0.493	-0.4109	-0.0722	-0.3964	0.7435	0.3807	0.8896	0.7614	0.8027
2002 TIN	peak	0.6619	0.4506	-0.1471	-0.2	-0.0309	0.19	-0.5569	0.8717	0.7349	0.8584	1.2169	1.054
2002 TIN	off-peak	-0.875	0.1446	-0.447	-0.351	-0.4161	-0.0017	-0.4194	0.9103	-0.0871	0.4439	0.6581	0.6936
2003 TIN	peak	0.7842	1.1901	0.0288	-0.3011	0.018	0.3513	-0.222	0.5963	0.2737	-0.4933	0.3882	1.0483
2003 TIN	off-peak	0.2361	0.7713	0.1791	-0.4924	-0.4897	-0.3577	-0.2159	0.6595	0.1605	0.5482	0.6927	0.8708
2004 TIN	peak	1.2662	0.958	0.1488	-0.1974	0.0588	0.1299	-0.4422	0.2895	0.3958	0.1907	0.4129	1.176
2004 TIN	off-peak	0.17	0.2825	-0.2684	-0.6077	-0.4935	-0.1755	-0.1804	0.2801	0.0213	0.433	0.4578	0.4561
2005 TIN	peak	1.1769	0.9548	-0.071	0.0804	0.1706	0.2596	-0.513	0.4996	0.5463	-0.0684	0.4173	1.3857
2005 TIN	off-peak	6.2644	0.1607	-0.6005	-0.8601	-0.6412	-0.2335	-0.2605	0.2672	0.0206	-0.6922	0.4917	0.3082
2006 TIN	peak	0.7955	0.6048	-0.3683	0.1022	-0.2335	0.0381	-0.6599	0.3446	0.3204	0.599	0.3567	1.2178
2006 TIN	off-peak	0.2617	-0.7368	-0.1778	-0.7105	-0.4412	-0.3876	-0.4774	0.2411	0.1519	1.1891	1.1094	0.9437
2007 TIN	peak	1.3417	0.2697	-0.3644	0.0452	0.1393	-0.1848	-0.7233	-0.0415	0.6403	0.7626	0.7061	0.907
2007 TIN	off-peak	0.2215	-0.0402	-0.1513	-0.3497	-0.1962	-0.1132	-0.7936	0.3232	0.5507	0.9501	0.8721	0.8912
2008 TIN	peak	1.1063	0.3597	-0.1709	0.1381	0.1855	-0.1638	-0.62	0.1363	0.8461	1.0509	0.5912	0.9421
2008 TIN	off-peak	0.5047	0.3785	0.2288	-0.1025	-0.0856	-0.255	-0.6044	0.071	-0.1388	1.2117	1.1816	1.1883

Table F5

Data: Historical industrial sector natural gas prices by type of service, NGTDM region.

Derivation: The historical industrial natural gas prices published in the *Natural Gas Annual (NGA)* only reflect gas purchased through local distribution companies. In order to approximate the average price to all industrial customers by service type and NGTDM region (HPGFINGR, HPGIINGR), data available at the Census Region level[97] from the Manufacturing Energy Consumption Survey (MECS)[98] for the years 1988, 1991, 1994, 1998, and 2002 were used to estimate an equation for the regional MECS price as a function of the regional NGA industrial price and the regional supply price (quantity-weighted average of the gas wellhead price and import price). The procedure is outlined below.

1) Assign average Census Division industrial price using econometrically derived equation:

$$PIN\_NG_{nr} = 1.00187 * \exp(0.039682) * PW\_NRG_{nr}^{0.231404} * HPIN_{nr}^{0.726227}$$

from estimating the following equation

$$\ln PIN\_NG_{nr} = \beta_0 + \beta_1 * \ln PW\_NRG_{nr} + \beta_2 * HPIN_{nr}$$

2) Assign prices to the NGTDM regions that represent subregions of Census Divisions by multiplying the Census Division price from step 1 by the subregion price (as published in the NGA), divided by the Census Division price (as published in the NGA). For the Pacific Division, the industrial price in Alaska from the NGA, with quantity weights, is used to approximate a Pacific Division price for the lower-48 (i.e., CA, WA, and OR), before this step is performed.

3) Core industrial prices are derived by applying an historical, regional, average average-to-firm price markup (FDIFF, in 1987$/Mcf, Northeast 0.11, North Central 0.14, South 0.67, West 0.39) to the established average regional industrial price (from step 2). Noncore prices are calculated so that the quantity-weighted average of the core and noncore prices equal the original regional estimate. The data used to generate the average-to-firm markups are presented below.

4) Finally, the peak and off-peak prices from the NGA are scaled to align with the core and noncore prices generated from step 3 on an average annual basis, to arrive at peak/off-peak, core/noncore industrial prices for the NGTDM regions.

[97]Through a special request, the Census Bureau generated MECS data by Census Region and by service type (core versus noncore) based on an assumption of which industrial classifications are more likely to consume most of their purchased natural gas in boilers (core) or non-boiler applications (noncore).

[98]A request was issued to the Census Bureau to obtain similar data from other MECS surveys to improve this estimation.

	Prices (87$/mcf)			Consumption (Bcf)		
	1988	**1991**	**1994**	**1988**	**1991**	**1994**
Core						
Northeast	3.39	3.05	3.04	335	299	310
North Central	3.04	2.37	2.42	864	759	935
South	2.91	2.40	2.53	643	625	699
West	3.21	2.70	2.55	217	204	227
Noncore						
Northeast	3.05	2.78	2.67	148	146	187
North Central	2.60	2.01	2.17	537	648	747
South	1.96	1.57	1.75	2517	2592	2970
West	2.54	2.19	1.91	347	440	528

	Price (87$/mcf)				
	1988	1991	1994	1998	2002
Northeast	3.297223	3.018058	2.941269	2.834076	3.498869
North Central	2.880355	2.247968	2.351399	2.247715	2.985983
South	2.162684	1.766014	1.939298	1.947017	2.634691
West	2.804912	2.398525	2.133228	2.217645	2.831414

Variables:

PIN_NG = Industrial natural gas prices by NGTDM region (1987$/Mcf)
PW_CDV = Average supply price by Census Division (1987$/Mcf)
PI_CDV = Industrial natural gas price from the NGA by Census Division (1987$/Mcf)
FDIFF = Average (1988, 1991, 1994) difference between the firm industrial price and the average industrial price by Census Region (1987$/Mcf)
PIN_FNG = Industrial core natural gas prices by NGTDM region (1987$/Mcf)
PIN_ING = Industrial noncore natural gas prices by NGTDM region (1987$/Mcf)
HPGFINGR = Industrial core natural gas prices by period and NGTDM region (1987$/Mcf)
HPGIINGR = Industrial noncore natural gas prices by period and NGTDM region (1987$/Mcf)

Regression Diagnostics and Parameter Estimates:

```
Dependent variable: LNMECS87
 Number of observations:  20

       Mean of dep. var. = .921802          LM het. test = .021529 [.883]
  Std. dev. of dep. var. = .190034         Durbin-Watson = 1.22472 [<.086]
 Sum of squared residuals = .067807      Jarque-Bera test = .977466 [.613]
    Variance of residuals = .398866E-02   Ramsey's RESET2 = .044807 [.835]
```

Std. error of regression = .063156		F (zero slopes) = 77.5121 [.000]	
R-squared = .901177		Schwarz B.I.C. = -23.9958	
Adjusted R-squared = .889550		Log likelihood = 28.4894	

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value	Symbol
C	.039682	.072242	.549291	[.590]	β_0
LNSUPPLYP87	.231404	.105606	2.19120	[.043]	β_1
LNNGAP87	.726227	.073700	9.85385	[.000]	β_2

Form of Forecasting Equation:

$$MECS87 = 1.00187 * e^{0.039682} SUPPLYP87^{0.231404} NGAP87^{0.726227}$$

where:

*MECS*87 = Manufacturer’s Energy Consumption Survey in US$87

*SUPPLYP*87 = supply price in US$87

*NGAP*87 = natural gas annual price in US$87

The term 1.00187 is an adjustment factor that is applied in cases where the value of “y” is predicted from an estimated equation where the dependent variable is the natural log of y. The adjustment is due to the fact that generally predictions of “y” using the first equation only tend to be biased downward. It is calculated by estimating the historical values of the dependent variable as a function of the estimated values for the same.

Table F6

Data: Equations for residential distribution tariffs

Author: Ernest Zampelli, SAIC, with summer intern Ben Laughlin, 2010.

Source: The source for the peak and off-peak data used in this estimation was the *Natural Gas Monthly*, DOE/EIA-0130. State level city gate and residential prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM regions) prices. The quantity-weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. The source for the number of residential customers was the Natural Gas Annual, DOE/EIA-0131.

Variables:

$TRS_{r,n,t}$	=	residential distributor tariff in the period n for region r (1987 dollars per Mcf) [$DTAR\_SF_1$]
REG_r	=	1, if observation is in region r, =0 otherwise
$QRS\_NUMR_{r,n,t}$	=	residential gas consumption per customer in the period for region r in year t (Bcf per thousand customers) [($BASQTY\_SF_1$+$BASQTY\_SI_1$)/NUMRS]
$NUMRS_{r,t}$	=	number of residential customers (thousands)
r	=	NGTDM region
n	=	network (1=peak, 2=off-peak)
t	=	year
$\alpha_{r,n}$	=	estimated parameters for regional dummy variables [PRSREGPK19]
$\beta_{1,n}$, $\beta_{2,n}$	=	estimated parameters
ρ_n	=	autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Residential distributor tariff equations for the peak and off-peak periods were estimated using panel data for the 12 NGTDM regions over the 1990 to 2009 time period. The equations were estimated in log-linear form with corrections for cross sectional heteroscedasticity and first order serial correlation using EViews. The general form for both estimating equations follows:

$$\ln TRS_{r,n,t} = \sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QRS\_NUMR_{r,n,t} + \beta_{2,n} * \ln NUMRS_{r,t} +$$

$$\rho_n * \ln TRS_{r,n,t-1} - \rho_n * (\sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QRS\_NUMR_{r,n,t-1} + \beta_{2,n} * \ln NUMRS_{r,t}$$

Regression Diagnostics and Parameter Estimates for the Peak Period:

Dependent Variable: LNTRS87
Method: Least Squares
Date: 07/22/10 Time: 16:32
Sample (adjusted): 2 240
Included observations: 239 after adjustments
Convergence achieved after 7 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=4)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQRS_NUMR	-0.607267	0.094552	-6.422580	0.0000
LN_NUMRS	0.162972	0.090462	1.801551	0.0730
REGION=1	-6.947036	1.103041	-6.298074	0.0000
REGION=2	-7.422527	1.201445	-6.178001	0.0000
REGION=3	-8.021596	1.217912	-6.586353	0.0000
REGION=4	-7.864109	1.156385	-6.800599	0.0000
REGION=5	-7.473760	1.153979	-6.476514	0.0000
REGION=6	-7.664540	1.121958	-6.831398	0.0000
REGION=7	-8.052452	1.177230	-6.840170	0.0000
REGION=8	-7.987073	1.121141	-7.124058	0.0000
REGION=9	-7.308704	1.060240	-6.893446	0.0000
REGION=10	-7.283411	1.060717	-6.866500	0.0000
REGION=11	-7.523595	1.085943	-6.928169	0.0000
REGION=12	-7.954022	1.209662	-6.575410	0.0000
AR(1), ρ	0.231296	0.068422	3.380459	0.0009

R-squared	0.911539	Mean dependent var	0.940050
Adjusted R-squared	0.906010	S.D. dependent var	0.384204
S.E. of regression	0.117789	Akaike info criterion	-1.379145
Sum squared resid	3.107810	Schwarz criterion	-1.160957
Log likelihood	179.8078	Hannan-Quinn criter.	-1.291221
Durbin-Watson stat	1.994101		

Regression Diagnostics and Parameter Estimates for the Off-peak Period:

Dependent Variable: LNTRS87
Method: Least Squares
Date: 07/22/10 Time: 16:31
Sample: 241 480
Included observations: 240
Convergence achieved after 6 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=4)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQRS_NUMR	-0.814968	0.085444	-9.538040	0.0000
LN_NUMRS	0.282301	0.111488	2.532127	0.0120
REGION=1	-11.06556	1.189130	-9.305589	0.0000
REGION=2	-11.46569	1.331512	-8.611025	0.0000
REGION=3	-11.99084	1.365602	-8.780628	0.0000
REGION=4	-11.81121	1.265735	-9.331497	0.0000
REGION=5	-11.52214	1.266859	-9.095045	0.0000
REGION=6	-11.67063	1.209285	-9.650856	0.0000

REGION=7	-11.86662	1.278193	-9.283902	0.0000
REGION=8	-11.80703	1.229651	-9.601944	0.0000
REGION=9	-11.19628	1.140432	-9.817580	0.0000
REGION=10	-10.93813	1.060071	-10.31830	0.0000
REGION=11	-11.32604	1.134872	-9.980016	0.0000
REGION=12	-12.06455	1.327790	-9.086182	0.0000
AR(1), ρ	0.202612	0.083183	2.435748	0.0156

R-squared	0.905922	Mean dependent var	1.272962
Adjusted R-squared	0.900069	S.D. dependent var	0.368928
S.E. of regression	0.116625	Akaike info criterion	-1.399238
Sum squared resid	3.060333	Schwarz criterion	-1.181698
Log likelihood	182.9086	Hannan-Quinn criter.	-1.311585
Durbin-Watson stat	2.010275		

Data used for peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TRS87	1.3013	1.0730	0.4048	0.3961	1.0185	0.6054	0.6114	0.4041	1.0087	1.4535	1.0112	0.9513
1990	NUMRS	14.4242	15.9210	16.2206	15.2533	15.2427	14.6570	15.5148	14.5549	13.5724	13.0339	13.7708	15.9587
1990	QRS_NUMR	-9.8137	-9.8268	-9.5457	-9.6821	-9.9747	-9.9839	-10.1121	-9.8411	-9.9340	-11.0881	-10.1387	-10.2906
1991	TRS87	1.3496	1.1217	0.4383	0.4061	0.9869	0.7178	0.6539	0.4200	0.8813	1.5632	1.0210	1.0692
1991	NUMRS	14.4330	15.9914	16.2352	15.2651	15.2648	14.6832	15.5257	14.5850	13.6744	13.0546	13.8374	15.9747
1991	QRS_NUMR	-9.8481	-9.8694	-9.4866	-9.5907	-9.9350	-9.9281	-10.0510	-9.7635	-9.9330	-11.1596	-10.1994	-10.4037
1992	TRS87	1.3843	1.1746	0.4187	0.4769	1.0595	0.7357	0.6413	0.4536	0.9455	1.5313	0.9832	1.0246
1992	NUMRS	14.4423	16.0036	16.2475	15.2807	15.3133	14.7090	15.5316	14.6128	13.6913	13.0644	13.8095	15.9800
1992	QRS_NUMR	-9.7463	-9.7981	-9.4989	-9.6974	-9.8973	-9.9207	-10.0994	-9.8291	-9.9947	-11.0110	-10.1482	-10.4125
1993	TRS87	1.3820	1.1496	0.4725	0.4174	1.0268	0.6689	0.5867	0.4285	0.9412	1.6365	0.9866	1.0188
1993	NUMRS	14.4511	15.9482	16.2628	15.3088	15.3177	14.7384	15.5461	14.6431	13.7500	13.0915	13.8235	15.9853
1993	QRS_NUMR	-9.7174	-9.6990	-9.4326	-9.5707	-9.8014	-9.8673	-10.0340	-9.7353	-9.8164	-11.1386	-10.1938	-10.3689
1994	TRS87	1.4626	1.2113	0.5602	0.5377	1.0417	0.7789	0.6270	0.3148	1.0047	1.5705	1.0989	1.0644
1994	NUMRS	14.4669	15.9546	16.2793	15.3186	15.3552	14.7660	15.5493	14.6859	13.8117	13.1179	13.8590	15.9927
1994	QRS_NUMR	-9.6833	-9.6305	-9.4214	-9.5819	-9.8242	-9.8557	-10.0686	-9.8535	-9.9180	-11.0983	-10.2387	-10.3976
1995	TRS87	1.4777	1.2395	0.4181	0.5394	1.0357	0.7752	0.6719	0.4867	1.0564	1.5497	1.1641	1.2479
1995	NUMRS	14.4722	15.9635	16.2956	15.3296	15.3786	14.7928	15.5719	14.7298	13.8644	13.1468	13.8953	16.0011
1995	QRS_NUMR	-9.8144	-9.7202	-9.4542	-9.6281	-9.8344	-9.8930	-10.1371	-9.9560	-10.0186	-11.0584	-10.4061	-10.5225
1996	TRS87	1.3476	1.0818	0.1781	0.5158	0.8316	0.3859	0.5277	0.3350	0.9486	1.4764	0.8042	1.0371
1996	NUMRS	14.4787	15.9705	16.3101	15.3458	15.4097	14.8172	15.5827	14.7820	13.9172	13.1648	13.9272	16.0128
1996	QRS_NUMR	-9.7463	-9.6610	-9.3922	-9.5186	-9.7506	-9.8066	-10.0178	-9.8489	-9.8830	-10.9631	-10.3015	-10.5316
1997	TRS87	1.4246	1.2644	0.5200	0.5224	1.0685	0.7789	0.5464	0.2708	0.8759	1.5913	0.8229	0.9658
1997	NUMRS	14.4942	15.9815	16.3246	15.3617	15.4343	14.8403	15.5943	14.8138	13.9636	13.1859	13.9709	16.0228
1997	QRS_NUMR	-9.8196	-9.7484	-9.4966	-9.6504	-9.9177	-9.9457	-10.0575	-9.8098	-9.9762	-11.2669	-10.1617	-10.4781
1998	TRS87	1.4327	1.2917	0.4904	0.6157	0.9988	0.8608	0.7975	0.5630	0.9999	1.6068	0.9482	1.2250
1998	NUMRS	14.4989	15.9974	16.3359	15.3965	15.4742	14.8582	15.6056	14.8560	14.0103	13.2044	14.0129	16.0361
1998	QRS_NUMR	-9.9191	-9.8890	-9.6541	-9.7858	-10.0032	-10.0339	-10.1671	-9.8718	-9.9315	-11.2087	-10.1565	-10.3678
1999	TRS87	1.5129	1.2759	0.4744	0.6043	0.7784	0.8467	0.7095	0.7222	0.9247	1.6374	1.0753	1.1647
1999	NUMRS	14.5139	15.9997	16.3533	15.3897	15.5150	14.8715	15.6069	14.8947	14.0632	13.2297	14.0591	16.0522
1999	QRS_NUMR	-9.9349	-9.7629	-9.5478	-9.7411	-10.0050	-10.0386	-10.3070	-9.9509	-9.9094	-11.3010	-10.3344	-10.3496
2000	TRS87	1.2459	0.9658	0.2874	0.5682	1.0392	0.6611	0.4867	0.4600	0.8809	1.5769	0.8454	1.0239
2000	NUMRS	14.5479	16.0179	16.3707	15.4080	15.5191	14.8989	15.6219	14.9377	14.1061	13.2568	14.0976	16.0564
2000	QRS_NUMR	-9.8027	-9.7135	-9.5247	-9.7105	-9.8176	-9.9435	-10.2082	-9.9300	-9.9268	-11.1472	-10.3574	-10.4820
2001	TRS87	1.1669	0.8359	0.4220	0.5104	0.9910	0.7410	0.6233	0.5086	0.9195	1.6954	0.7993	0.7641
2001	NUMRS	14.5525	16.0404	16.3786	15.4165	15.5482	14.9102	15.6258	14.9727	14.1408	13.2883	14.1309	16.0808
2001	QRS_NUMR	-9.8536	-9.7796	-9.5948	-9.6984	-9.9725	-9.9584	-10.1280	-9.8815	-9.8992	-11.1316	-10.2740	-10.4422
2002	TRS87	1.3252	1.0061	0.1798	0.5499	1.1709	0.9131	0.7894	0.6021	1.3468	1.7721	1.2823	1.0116
2002	NUMRS	14.5638	16.0403	16.3942	15.4318	15.5633	14.9165	15.6392	15.0026	14.1702	13.3108	14.1679	16.0935
2002	QRS_NUMR	-9.9004	-9.8433	-9.6303	-9.9500	-9.9503	-9.9813	-10.1525	-9.8950	-10.0019	-11.2021	-10.3534	-10.5047
2003	TRS87	1.0640	0.9727	0.2343	0.3112	0.9532	0.7328	0.4904	0.2461	0.8771	1.7006	0.9723	0.9677
2003	NUMRS	14.5811	16.0513	16.3998	15.4423	15.5781	14.9256	15.6478	15.0353	14.2350	13.3332	14.1914	16.1013
2003	QRS_NUMR	-9.7270	-9.6751	-9.5145	-9.7046	-9.8285	-9.9254	-10.1285	-9.9871	-10.1089	-11.1387	-10.4292	-10.5824
2004	TRS87	1.4448	1.1049	0.4562	0.5844	1.1471	0.9384	0.7348	0.4769	0.9936	1.8242	1.0512	0.9869
2004	NUMRS	14.5756	16.0534	16.4051	15.4520	15.5898	14.9327	15.6576	15.0708	14.2355	13.3677	14.2230	16.1165

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
2004	QRS_NUMR	-9.8007	-9.7289	-9.5665	-9.7569	-9.8660	-10.0182	-10.2595	-9.9870	-10.0385	-11.2037	-10.3556	-10.5074
2005	TRS87	1.3379	1.0112	0.5253	0.5977	1.1991	1.1059	0.8346	0.6471	1.0996	1.8538	1.0791	1.0613
2005	NUMRS	14.5778	16.0534	16.4355	15.4628	15.6158	14.9387	15.6603	15.1071	14.2811	13.3940	14.2685	16.1330
2005	QRS_NUMR	-9.7550	-9.7055	-9.5980	-9.7940	-9.9176	-10.0749	-10.2975	-10.0114	-10.0741	-11.2697	-10.4966	-10.6082
2006	TRS87	1.4382	1.0702	0.5922	0.7802	1.3712	1.1594	0.9223	0.6719	1.1872	1.9608	1.2392	1.0536
2006	NUMRS	14.6041	16.0667	16.4213	15.4743	15.6183	14.9404	15.6673	15.1360	14.3135	13.4197	14.2995	16.1530
2006	QRS_NUMR	-9.9612	-9.9080	-9.7920	-9.9646	-10.1252	-10.2239	-10.4576	-10.0484	-10.0769	-11.3045	-10.5704	-10.6089
2007	TRS87	1.4864	1.0909	0.4472	0.6683	1.2977	0.9723	0.6249	0.3350	1.3113	1.8413	1.2638	0.9427
2007	NUMRS	14.6116	16.0784	16.4269	15.4747	15.6430	14.9418	15.6896	15.1576	14.3400	13.4342	14.3264	16.1636
2007	QRS_NUMR	-9.8358	-9.7697	-9.6440	-9.8083	-10.0464	-10.1692	-10.2719	-9.9694	-10.0544	-11.4291	-10.4542	-10.5827
2008	TRS87	1.3928	1.1184	0.4855	0.5188	1.2655	0.9639	0.6981	0.2994	1.1499	1.7733	1.1499	0.9547
2008	NUMRS	14.6286	16.0706	16.4277	15.4811	15.6491	14.9374	15.6981	15.1769	14.3588	13.4288	14.3374	16.1708
2008	QRS_NUMR	-9.8906	-9.7897	-9.5915	-9.7199	-10.0515	-10.0780	-10.2801	-9.9503	-10.0494	-11.3525	-10.4683	-10.5638
2009	TRS87	1.6335	1.2695	0.7903	0.8171	1.2355	1.1304	0.9066	0.5545	1.2369	1.9854	1.2550	1.0463
2009	NUMRS	14.5832	16.0687	16.4454	15.4815	15.6506	14.9563	15.6793	15.1583	14.3126	13.4289	14.3197	16.1646
2009	QRS_NUMR	-9.9948	-9.7392	-9.6625	-9.7911	-9.9657	-10.1392	-10.3138	-10.0136	-9.9490	-11.4385	-10.5687	-10.6136

Data used for off-peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	**Mid Atl**	**E.N. Cntrl**	**W.N. Cntrl**	**S.Atl-FL**	**E.S. Cntrl**	**W.S. Cntrl**	**Mtn-AZNM**	**WA/OR**	**Florida**	**AZ/NM**	**CA/HI**
1990	TRS87	1.4572	1.3623	0.7696	0.7120	1.2790	1.0152	1.1575	0.5134	1.2202	1.8083	1.4110	0.9509
1990	NUMRS	14.4242	15.9210	16.2206	15.2533	15.2427	14.6570	15.5148	14.5549	13.5724	13.0339	13.7708	15.9587
1990	QRS_NUMR	-10.1737	-10.1963	-9.9287	-10.1549	-10.4345	-10.4700	-10.5254	-10.1992	-10.3260	-11.2459	-10.7420	-10.5401
1991	TRS87	1.4697	1.3661	0.7622	0.7571	1.2565	1.0811	1.1499	0.5218	1.1378	1.8672	1.3903	1.1285
1991	NUMRS	14.4330	15.9914	16.2352	15.2651	15.2648	14.6832	15.5257	14.5850	13.6744	13.0546	13.8374	15.9747
1991	QRS_NUMR	-10.2129	-10.2794	-9.9370	-10.1508	-10.4257	-10.5158	-10.5282	-10.1586	-10.2602	-11.2210	-10.6974	-10.4672
1992	TRS87	1.3002	1.2934	0.6785	0.7367	1.1210	0.9490	1.1311	0.3660	1.1894	1.8746	1.3697	1.0112
1992	NUMRS	14.4423	16.0036	16.2475	15.2807	15.3133	14.7090	15.5316	14.6128	13.6913	13.0644	13.8095	15.9800
1992	QRS_NUMR	-10.0309	-10.1508	-9.8551	-10.1300	-10.3308	-10.4581	-10.5444	-10.2928	-10.4391	-11.1796	-10.7692	-10.5941
1993	TRS87	1.2436	1.3337	0.8002	0.7756	1.2006	0.9381	1.0325	0.5110	1.0770	1.9327	1.3486	1.0533
1993	NUMRS	14.4511	15.9482	16.2628	15.3088	15.3177	14.7384	15.5461	14.6431	13.7500	13.0915	13.8235	15.9853
1993	QRS_NUMR	-10.0770	-10.1454	-9.8863	-10.0785	-10.3702	-10.4200	-10.4423	-10.1556	-10.2861	-11.1613	-10.7189	-10.5619
1994	TRS87	1.3990	1.5250	0.9030	0.7509	1.3126	1.1703	1.2499	0.5446	1.1378	1.9370	1.3880	1.1716
1994	NUMRS	14.4669	15.9546	16.2793	15.3186	15.3552	14.7660	15.5493	14.6859	13.8117	13.1179	13.8590	15.9927
1994	QRS_NUMR	-10.2330	-10.2089	-10.0332	-10.2796	-10.5232	-10.6547	-10.6284	-10.2230	-10.3182	-11.2742	-10.7146	-10.4615
1995	TRS87	1.3676	1.5059	0.6355	0.7971	1.2447	1.0378	1.2093	0.6871	1.2250	1.9244	1.4344	1.2686
1995	NUMRS	14.4722	15.9635	16.2956	15.3296	15.3786	14.7928	15.5719	14.7298	13.8644	13.1468	13.8953	16.0011
1995	QRS_NUMR	-10.2486	-10.2046	-9.8990	-10.1283	-10.4491	-10.5672	-10.6332	-10.1208	-10.3370	-11.2799	-10.7640	-10.5265
1996	TRS87	1.2179	1.4156	0.7251	0.8011	1.2945	1.0420	1.1490	0.5939	1.0515	1.9081	1.2404	1.1641
1996	NUMRS	14.4787	15.9705	16.3101	15.3458	15.4097	14.8172	15.5827	14.7820	13.9172	13.1648	13.9272	16.0128
1996	QRS_NUMR	-10.1759	-10.0992	-9.8632	-10.1027	-10.3690	-10.4690	-10.5870	-10.1797	-10.2427	-11.1834	-10.7557	-10.5586
1997	TRS87	1.3737	1.2977	0.6896	0.7006	1.3048	1.1594	1.1628	0.7333	0.9636	1.9840	1.4978	1.1817
1997	NUMRS	14.4942	15.9815	16.3246	15.3617	15.4343	14.8403	15.5943	14.8138	13.9636	13.1859	13.9709	16.0228
1997	QRS_NUMR	-10.1844	-10.1359	-9.9058	-10.1853	-10.3817	-10.5536	-10.5969	-10.2171	-10.2644	-11.3449	-10.8543	-10.6133
1998	TRS87	1.3538	1.4852	0.8912	0.9517	1.4389	1.2096	1.3172	0.9817	1.0821	1.9462	1.6148	1.2596
1998	NUMRS	14.4989	15.9974	16.3359	15.3965	15.4742	14.8582	15.6056	14.8560	14.0103	13.2044	14.0129	16.0361
1998	QRS_NUMR	-10.3094	-10.2789	-10.1529	-10.3891	-10.6234	-10.7340	-10.8047	-10.2558	-10.3918	-11.2958	-10.8069	-10.4719
1999	TRS87	1.0889	1.3689	0.7701	0.9219	1.3943	1.1805	1.2698	0.9010	1.0445	1.9481	1.4173	1.0852
1999	NUMRS	14.5139	15.9997	16.3533	15.3897	15.5150	14.8715	15.6069	14.8947	14.0632	13.2297	14.0591	16.0522
1999	QRS_NUMR	-10.2181	-10.2620	-10.1580	-10.3818	-10.6582	-10.7539	-10.8316	-10.2372	-10.2219	-11.2957	-10.7622	-10.4560
2000	TRS87	1.2021	1.1666	0.7641	0.9369	1.2873	1.2075	1.2439	0.7683	1.0360	1.9498	1.0543	1.1401
2000	NUMRS	14.5479	16.0179	16.3707	15.4080	15.5191	14.8989	15.6219	14.9377	14.1061	13.2568	14.0976	16.0564
2000	QRS_NUMR	-10.2939	-10.2010	-10.0886	-10.3475	-10.4772	-10.7147	-10.7695	-10.2952	-10.2961	-11.3271	-10.7458	-10.5203
2001	TRS87	1.5986	1.5336	0.8858	1.1518	1.4931	1.4535	1.3543	1.2768	1.4339	2.1949	1.5484	1.1171
2001	NUMRS	14.5525	16.0404	16.3786	15.4165	15.5482	14.9102	15.6258	14.9727	14.1408	13.2883	14.1309	16.0808
2001	QRS_NUMR	-10.3591	-10.3157	-10.2289	-10.4221	-10.6404	-10.8037	-10.8797	-10.3798	-10.1673	-11.3560	-10.9661	-10.6333
2002	TRS87	1.1783	1.3180	0.4898	0.9135	1.4253	1.3279	1.2407	0.9776	1.3118	2.0916	1.6413	1.0325
2002	NUMRS	14.5638	16.0403	16.3942	15.4318	15.5633	14.9165	15.6392	15.0026	14.1702	13.3108	14.1679	16.0935
2002	QRS_NUMR	-10.2894	-10.2494	-10.0372	-10.4213	-10.5565	-10.7848	-10.8196	-10.2990	-10.3072	-11.3809	-11.0132	-10.5959
2003	TRS87	1.6186	1.5151	0.9115	1.0726	1.5988	1.4413	1.5072	0.9738	1.0335	2.2077	1.6160	1.0526
2003	NUMRS	14.5811	16.0513	16.3998	15.4423	15.5781	14.9256	15.6478	15.0353	14.2350	13.3332	14.1914	16.1013
2003	QRS_NUMR	-10.2544	-10.2498	-10.1390	-10.4069	-10.6046	-10.8938	-10.9634	-10.3580	-10.3962	-11.4032	-10.9974	-10.5834
2004	TRS87	1.4646	1.4598	0.8796	1.1230	1.6372	1.4839	1.5330	0.9555	1.1681	2.1940	1.6409	0.9058
2004	NUMRS	14.5756	16.0534	16.4051	15.4520	15.5898	14.9327	15.6576	15.0708	14.2355	13.3677	14.2230	16.1165
2004	QRS_NUMR	-10.3369	-10.3011	-10.2379	-10.5061	-10.6721	-10.9527	-10.9803	-10.3803	-10.4749	-11.3955	-11.0150	-10.6372
2005	TRS87	1.2565	1.3067	0.8920	1.0574	1.5239	1.4063	1.5061	0.9768	1.1534	2.0852	1.4960	0.9310

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
2005	NUMRS	14.5778	16.0534	16.4355	15.4628	15.6158	14.9387	15.6603	15.1071	14.2811	13.3940	14.2685	16.1330
2005	QRS_NUMR	-10.3301	-10.3133	-10.2901	-10.5292	-10.6477	-10.8541	-10.9974	-10.4205	-10.4464	-11.3454	-11.0278	-10.6804
2006	TRS87	1.5839	1.4591	0.9431	1.1597	1.7837	1.5063	1.6380	0.8924	1.4159	2.2101	1.8361	1.1429
2006	NUMRS	14.6041	16.0667	16.4213	15.4743	15.6183	14.9404	15.6673	15.1360	14.3135	13.4197	14.2995	16.1530
2006	QRS_NUMR	-10.4060	-10.4084	-10.2527	-10.5223	-10.6889	-10.9109	-11.0536	-10.4466	-10.4555	-11.4250	-11.0867	-10.6868
2007	TRS87	1.5611	1.4748	1.0919	1.3310	1.7778	1.4913	1.5573	0.9662	1.4900	2.1891	1.8070	1.1891
2007	NUMRS	14.6116	16.0784	16.4269	15.4747	15.6430	14.9418	15.6896	15.1576	14.3400	13.4342	14.3264	16.1636
2007	QRS_NUMR	-10.3719	-10.3408	-10.3127	-10.5771	-10.6998	-10.9956	-11.0435	-10.4942	-10.4203	-11.4010	-11.1591	-10.7360
2008	TRS87	1.4298	1.4639	1.2161	1.2273	1.6152	1.4734	1.4704	0.7659	0.9869	2.0844	1.8111	1.2459
2008	NUMRS	14.6286	16.0706	16.4277	15.4811	15.6491	14.9374	15.6981	15.1769	14.3588	13.4288	14.3374	16.1708
2008	QRS_NUMR	-10.3753	-10.3351	-10.2613	-10.4774	-10.6242	-10.8958	-11.0306	-10.4334	-10.3485	-11.3981	-11.1367	-10.7886
2009	TRS87	1.7502	1.6044	1.1547	1.2444	1.8710	1.6198	1.6156	0.9761	1.5667	2.3046	1.8086	1.1597
2009	NUMRS	14.5832	16.0687	16.4454	15.4815	15.6506	14.9563	15.6793	15.1583	14.3126	13.4289	14.3197	16.1646
2009	QRS_NUMR	-10.4626	-10.3705	-10.2891	-10.5011	-10.7517	-10.9740	-10.9774	-10.3727	-10.3909	-11.4718	-11.0855	-10.7547

Table F7

Data: Equation for commercial distribution tariffs

Author: Ernest Zampelli, SAIC, with Ben Laughlin, EIA Intern, 2010.

Source: The source for the peak and off-peak data used in this estimation was the *Natural Gas Monthly*, DOE/EIA-0130. State level city gate and commercial prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM regions) prices. The quantity-weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. Historical commercial floorspace data by census division were extracted from the NEMS model and allocated to NGTDM region using Census population figures.

Variables:

$TCM_{r,n,t}$	=	commercial distributor tariff in region r, network n (1987 dollars per Mcf) [$DTAR\_SF_2$]
REG_r	=	1, if observation is in region r, =0 otherwise
$QCM\_FLRr_{r,n,t}$	=	commercial gas consumption per floorspace for region r in year t (Bcf) [($BASQTY\_SF_2$+$BASQTY\_SI_2$)/FLRSPC12]
$FLR_{r,t}$	=	commercial floorspace for region r in year t (estimated in thousand square feet) [FLRSPC12]
r	=	NGTDM region
n	=	network (1=peak, 2=off-peak)
t	=	year
$\alpha_{r,n}$	=	estimated parameters for regional dummy variables [PCMREGPK13]
$\beta_{1,n}$,$\beta_{2,n}$	=	estimated parameters
ρ_n	=	autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The commercial distributor tariff equation was estimated using panel data for the 12 NGTDM regions over the 1990 to 2009 time period. The equation was estimated in log-linear form with corrections for cross sectional heteroscedasticity and first order serial correlation using EViews. The form of the estimated equation follows:

$$\ln TCM_{r,n,t} = \sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QCM\_FLR_{r,n,t} + \beta_{2,n} * \ln FLR_{r,t} +$$
$$\rho_n * \ln TCM_{r,n,t-1} - \rho_n * (\sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QCM\_FLR_{r,n,t-1} + \beta_{2,n} * \ln NUMCM_{r,t-1})$$

Regression Diagnostics and Parameter Estimates for the Peak Period

Dependent Variable: LNTCM87
Method: Least Squares
Date: 07/23/10 Time: 08:03
Sample (adjusted): 2 240
Included observations: 239 after adjustments
Convergence achieved after 9 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=4)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQCM_FLR	-0.217322	0.129951	-1.672341	0.0959
LNFLR	0.218189	0.121009	1.803081	0.0727
REGION=1	-4.498378	1.340720	-3.355196	0.0009
REGION=2	-4.852790	1.408476	-3.445420	0.0007
REGION=3	-5.471895	1.435476	-3.811903	0.0002
REGION=4	-5.266668	1.364229	-3.860545	0.0001
REGION=5	-5.054427	1.410819	-3.582619	0.0004
REGION=6	-4.975067	1.349163	-3.687521	0.0003
REGION=7	-5.517942	1.406269	-3.923816	0.0001
REGION=8	-5.253175	1.305366	-4.024293	0.0001
REGION=9	-4.795673	1.307829	-3.666896	0.0003
REGION=10	-5.051970	1.397162	-3.615881	0.0004
REGION=11	-4.899262	1.299003	-3.771555	0.0002
REGION=12	-4.817270	1.405236	-3.428085	0.0007
AR(1)	0.284608	0.083893	3.392527	0.0008

R-squared	0.809134	Mean dependent var	0.594811
Adjusted R-squared	0.797204	S.D. dependent var	0.347177
S.E. of regression	0.156344	Akaike info criterion	-0.812814
Sum squared resid	5.475313	Schwarz criterion	-0.594626
Log likelihood	112.1313	Hannan-Quinn criter.	-0.724890
Durbin-Watson stat	1.979180		

Regression Diagnostics and Parameter Estimates for the Off-Peak Period

Dependent Variable: LNTCM87
Method: Least Squares
Date: 07/23/10 Time: 08:04
Sample: 241 480
Included observations: 240
Convergence achieved after 6 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=4)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQCM_FLRSPC	-0.613588	0.209576	-2.927752	0.0038
LNFLRSPC	0.530831	0.213552	2.485719	0.0137
REGION=1	-13.87098	1.869814	-7.418373	0.0000
REGION=2	-14.12193	2.052895	-6.879033	0.0000
REGION=3	-14.49560	2.085660	-6.950127	0.0000
REGION=4	-14.29389	1.944700	-7.350175	0.0000
REGION=5	-14.37939	2.005218	-7.170990	0.0000
REGION=6	-13.98336	1.889625	-7.400073	0.0000

REGION=7	-14.50539	2.000913	-7.249384	0.0000
REGION=8	-13.81237	1.894236	-7.291790	0.0000
REGION=9	-13.71773	1.813711	-7.563346	0.0000
REGION=10	-14.29647	1.877570	-7.614347	0.0000
REGION=11	-13.50724	1.778116	-7.596376	0.0000
REGION=12	-14.05762	2.001953	-7.021954	0.0000
AR(1)	0.166956	0.091737	1.819954	0.0701

R-squared	0.603286	Mean dependent var	0.577749
Adjusted R-squared	0.578601	S.D. dependent var	0.335016
S.E. of regression	0.217477	Akaike info criterion	-0.152989
Sum squared resid	10.64162	Schwarz criterion	0.064551
Log likelihood	33.35864	Hannan-Quinn criter.	-0.065336
Durbin-Watson stat	1.997625		

Data used for peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TCM87	1.03354	0.782073	0.14842	0.042101	0.696143	0.430483	0.206201	0.028587	0.679555	0.735248	0.541161	0.904218
1990	QCM_FLR	-10.80819	-10.27518	-10.02571	-10.0121	-10.87259	-10.66464	-10.6939	-10.05054	-10.88697	-12.19567	-10.64772	-10.65706
1990	FLR	14.73416	15.69451	15.92281	15.07962	15.5246	14.82673	15.50667	14.31229	14.34193	14.8613	13.94832	15.48136
1991	TCM87	1.008688	0.80245	0.200489	0.090754	0.643432	0.518198	0.224742	0.058269	0.615186	0.76314	0.578297	1.0654
1991	QCM_FLR	-10.78194	-10.22102	-9.971767	-9.929256	-10.76971	-10.60622	-10.60989	-9.986422	-10.86598	-12.15423	-10.671	-10.80858
1991	FLR	14.74157	15.70491	15.93733	15.09204	15.55072	14.84239	15.51601	14.33424	14.36901	14.88742	13.97028	15.50845
1992	TCM87	1.074661	0.861201	0.193921	0.170586	0.711478	0.563608	0.322083	0.08526	0.658556	0.709021	0.549277	1.072268
1992	QCM_FLR	-10.67296	-10.15695	-9.984192	-10.02488	-10.69684	-10.61159	-10.66214	-10.05214	-10.96197	-12.10189	-10.66952	-10.77438
1992	FLR	14.74724	15.71275	15.94971	15.10304	15.57115	14.85401	15.52609	14.35083	14.38809	14.90785	13.98686	15.52753
1993	TCM87	1.017041	0.82242	0.265436	0.131905	0.680062	0.514618	0.288931	0.130151	0.625404	0.920283	0.581657	1.135587
1993	QCM_FLR	-10.61099	-10.14154	-9.926096	-9.900956	-10.64854	-10.54903	-10.68735	-9.946373	-10.76914	-12.1597	-10.7212	-10.84729
1993	FLR	14.75353	15.71675	15.96006	15.1135	15.58787	14.86603	15.53845	14.36863	14.40303	14.92458	14.00466	15.54246
1994	TCM87	1.17619	0.949339	0.377751	0.309688	0.710004	0.648673	0.266969	-0.037702	0.720762	0.729961	0.702602	1.439124
1994	QCM_FLR	-10.35558	-10.09798	-9.894967	-9.90904	-10.65618	-10.51963	-10.67386	-10.01784	-10.85795	-12.16941	-10.77524	-10.88982
1994	FLR	14.75796	15.72214	15.97161	15.12337	15.60436	14.88037	15.55029	14.39101	14.41575	14.94106	14.02705	15.55519
1995	TCM87	1.130434	0.950885	0.228728	0.249201	0.708036	0.628075	0.276115	0.18648	0.783445	0.727065	0.781616	1.382788
1995	QCM_FLR	-10.43041	-10.10463	-9.908138	-9.943346	-10.64013	-10.52523	-10.63409	-10.10654	-10.91288	-12.16089	-10.87959	-10.88643
1995	FLR	14.76406	15.72657	15.98518	15.1362	15.6225	14.89741	15.56682	14.41638	14.42795	14.9592	14.05242	15.56738
1996	TCM87	0.984697	0.874218	-0.04919	0.27079	0.548121	0.135405	0.138892	-0.019183	0.64815	0.639219	0.322808	1.107572
1996	QCM_FLR	-10.34278	-9.983987	-9.842353	-9.848968	-10.62702	-10.44972	-10.65972	-10.0069	-10.77339	-12.14789	-10.81071	-11.03641
1996	FLR	14.77156	15.73278	15.99937	15.15122	15.6444	14.91814	15.58439	14.44409	14.44094	14.98111	14.08013	15.58038
1997	TCM87	1.108893	0.927428	0.336472	0.222343	0.738598	0.559616	0.195567	-0.139262	0.475613	0.667316	0.360468	1.096276
1997	QCM_FLR	-10.30902	-10.00031	-9.948278	-9.98826	-10.68835	-10.55067	-10.5866	-9.999211	-10.86226	-12.31262	-10.71917	-10.94718
1997	FLR	14.78041	15.73888	16.01425	15.16549	15.6683	14.9417	15.60114	14.47542	14.45301	15.00501	14.11146	15.59244
1998	TCM87	1.06264	0.691646	0.300845	0.277632	0.718327	0.675492	0.447247	0.275356	0.617345	0.823298	0.609222	1.234308
1998	QCM_FLR	-10.39582	-9.992437	-10.09763	-10.06498	-10.71608	-10.66425	-10.75371	-10.09564	-10.80522	-12.32806	-10.73728	-10.96726
1998	FLR	14.79058	15.74669	16.03036	15.1816	15.69627	14.96628	15.62199	14.50829	14.46986	15.03297	14.14433	15.60929
1999	TCM87	1.021371	0.608678	0.291176	0.29565	0.561899	0.642906	0.280657	0.464363	0.58389	0.822859	0.687632	1.094604
1999	QCM_FLR	-10.59798	-9.933422	-10.01313	-10.06831	-10.72396	-10.66884	-10.76822	-10.20156	-10.74532	-12.35381	-10.84215	-10.95635
1999	FLR	14.80814	15.7567	16.04907	15.20068	15.72808	14.99202	15.64769	14.55063	14.49341	15.06479	14.18667	15.63284
2000	TCM87	0.813593	1.010509	0.002996	0.24686	0.687129	0.403463	-0.115411	0.111541	0.594431	0.690143	0.144966	0.967744
2000	QCM_FLR	-10.52122	-9.982545	-9.976626	-10.04653	-10.673	-10.60803	-10.71636	-10.16844	-10.7873	-12.1577	-10.87075	-11.04346
2000	FLR	14.82306	15.76907	16.06954	15.22189	15.76349	15.01802	15.67919	14.59011	14.51777	15.10019	14.22614	15.65721
2001	TCM87	0.740985	0.905432	0.128393	0.191446	0.771034	0.570414	-0.071496	0.242946	0.535908	1.127524	0.222343	0.726582
2001	QCM_FLR	-10.5722	-10.07162	-10.03531	-10.04857	-10.79009	-10.65373	-10.74992	-10.12952	-10.76708	-12.16264	-10.87023	-11.06204
2001	FLR	14.84233	15.78239	16.08961	15.2449	15.79681	15.04719	15.70677	14.6275	14.54296	15.13352	14.26353	15.6824
2002	TCM87	0.995102	0.442118	0.1415	0.203757	0.764072	0.731887	0.350657	0.360468	1.055705	1.118742	0.911479	0.885419
2002	QCM_FLR	-10.63463	-10.05163	-10.1255	-10.27543	-10.77561	-10.70046	-10.66041	-10.1548	-10.89604	-12.07748	-10.91055	-11.1448
2002	FLR	14.86432	15.79755	16.10825	15.26372	15.82963	15.0726	15.73421	14.66104	14.56744	15.16634	14.29707	15.70687
2003	TCM87	0.735728	0.82154	-0.043952	-0.009041	0.517006	0.508623	0.024693	-0.149661	0.515813	1.028547	0.442761	0.789366
2003	QCM_FLR	-10.60418	-9.934664	-9.984421	-10.07127	-10.73325	-10.63397	-10.67996	-10.25794	-10.94268	-12.1272	-10.99802	-11.08346
2003	FLR	14.87915	15.81076	16.124	15.28423	15.8558	15.09277	15.75895	14.68954	14.58792	15.1925	14.32557	15.72736
2004	TCM87	1.160334	0.913487	0.180653	0.280657	0.752359	0.666803	0.349952	0.094401	0.834213	1.166582	0.519984	0.799757
2004	QCM_FLR	-10.65883	-9.927092	-10.04934	-10.10882	-10.72775	-10.70777	-10.79844	-10.24872	-10.90133	-12.10691	-10.9337	-11.14323
2004	FLR	14.8915	15.82207	16.13839	15.30039	15.88185	15.11195	15.78199	14.71552	14.60498	15.21855	14.35156	15.74441
2005	TCM87	1.066433	0.756122	0.198031	0.318454	0.733329	0.942738	0.486738	0.366724	0.740985	1.011964	0.555608	0.914689
2005	QCM_FLR	-10.65271	-10.03913	-10.07135	-10.17298	-10.75486	-10.78261	-10.93415	-10.27977	-10.90604	-12.12498	-11.03518	-11.20321
2005	FLR	14.90435	15.83166	16.15338	15.31553	15.90631	15.13114	15.80292	14.74137	14.62178	15.24301	14.37741	15.76122
2006	TCM87	1.111199	0.781158	0.364643	0.509224	0.94585	0.92267	0.485508	0.423305	0.945461	1.307792	0.771034	0.947789
2006	QCM_FLR	-10.80154	-10.20122	-10.25512	-10.32185	-10.91544	-10.88917	-11.06584	-10.31421	-10.89834	-12.28774	-11.06119	-11.18639
2006	FLR	14.92068	15.84244	16.17045	15.33077	15.93231	15.15151	15.82449	14.7725	14.63929	15.26902	14.40853	15.77872
2007	TCM87	1.20627	0.597737	0.206201	0.408128	0.905028	0.699626	0.105261	0.038259	1.04486	1.032116	0.782988	0.732368
2007	QCM_FLR	-10.64449	-10.08287	-10.14895	-10.20875	-10.86095	-10.87075	-10.94939	-10.26239	-10.87505	-12.31859	-11.02282	-11.12961
2007	FLR	14.93262	15.85366	16.18633	15.34587	15.95991	15.1722	15.84616	14.80524	14.65694	15.29661	14.44127	15.79638
2008	TCM87	1.045212	0.580538	0.099845	0.245296	0.81978	0.683602	0.142367	-0.042908	0.821101	1.002101	0.560758	0.797958
2008	QCM_FLR	-10.70065	-10.08087	-10.08169	-10.10907	-10.88544	-10.82181	-10.96436	-10.25204	-10.86054	-12.33066	-11.05978	-11.13563

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
2008	FLR	14.946	15.86429	16.20345	15.36096	15.98527	15.19212	15.87062	14.83697	14.67404	15.32198	14.473	15.81347
2009	TCM87	1.185096	0.609222	0.404798	0.444686	0.78527	0.897719	0.447886	0.214305	0.950499	1.03176	0.65752	0.783445
2009	QCM_FLR	-10.72952	-10.06608	-10.12776	-10.18844	-10.85652	-10.88899	-10.99863	-10.33785	-10.83499	-12.34896	-11.17492	-11.19006
2009	FLR	14.95814	15.87473	16.21753	15.37525	16.00654	15.20937	15.88914	14.86197	14.68849	15.34324	14.49801	15.82793

Data used for off-peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	**Mid Atl**	**E.N. Cntrl**	**W.N. Cntrl**	**S.Atl-FL**	**E.S. Cntrl**	**W.S. Cntrl**	**Mtn-AZNM**	**WA/OR**	**Florida**	**AZ/NM**	**CA/HI**
1990	TCM87	0.81978	0.711969	0.379805	-0.177931	0.630207	0.528862	0.183155	-0.185125	0.738121	0.738121	0.564177	0.534151
1990	QCM_FLR	-10.90124	-10.34489	-10.31414	-10.18253	-10.96697	-10.85666	-10.5901	-10.29073	-11.02909	-11.77349	-10.73081	-10.38875
1990	FLR	14.73416	15.69451	15.92281	15.07962	15.5246	14.82673	15.50667	14.31229	14.34193	14.8613	13.94832	15.48136
1991	TCM87	0.818016	0.702602	0.413433	-0.080126	0.578858	0.560758	0.221542	-0.176737	0.702602	0.730443	0.666803	0.728514
1991	QCM_FLR	-10.9393	-10.37896	-10.37715	-10.1497	-10.89713	-10.89184	-10.59688	-10.25007	-10.93988	-11.7143	-10.73172	-10.31648
1991	FLR	14.74157	15.70491	15.93733	15.09204	15.55072	14.84239	15.51601	14.33424	14.36901	14.88742	13.97028	15.50845
1992	TCM87	0.513422	0.700123	0.262364	-0.125563	0.429832	0.430483	0.087095	-0.55687	0.782073	0.693147	0.491031	0.436318
1992	QCM_FLR	-10.7426	-10.30278	-10.2948	-10.18815	-10.82841	-10.83675	-10.55567	-10.36185	-11.10669	-11.68164	-10.67683	-10.38468
1992	FLR	14.74724	15.71275	15.94971	15.10304	15.57115	14.85401	15.52609	14.35083	14.38809	14.90785	13.98686	15.52753
1993	TCM87	0.14842	0.671924	0.438255	0.059212	0.506215	0.442761	0.132781	-0.125563	0.677526	0.946238	0.567584	0.850151
1993	QCM_FLR	-10.76579	-10.33389	-10.30689	-10.20689	-10.84683	-10.79649	-10.57541	-10.22038	-11.00829	-11.6948	-10.64436	-10.5797
1993	FLR	14.75353	15.71675	15.96006	15.1135	15.58787	14.86603	15.53845	14.36863	14.40303	14.92458	14.00466	15.54246
1994	TCM87	0.365337	0.90987	0.555608	-0.142716	0.559044	0.620576	0.367417	-0.015114	0.703098	0.845439	0.733329	1.214022
1994	QCM_FLR	-10.57619	-10.34363	-10.38704	-10.28376	-10.88405	-10.89237	-10.6291	-10.23104	-10.98642	-11.76509	-10.68369	-10.49269
1994	FLR	14.75796	15.72214	15.97161	15.12337	15.60436	14.88037	15.55029	14.39101	14.41575	14.94106	14.02705	15.55519
1995	TCM87	0.436318	0.880456	0.265436	0.051643	0.555034	0.525911	0.170586	0.276115	0.815365	0.727065	0.758935	1.09293
1995	QCM_FLR	-10.55041	-10.25587	-10.26514	-10.18332	-10.83986	-10.85856	-10.48104	-10.1478	-10.98213	-11.78257	-10.71065	-10.41359
1995	FLR	14.76406	15.72657	15.98518	15.1362	15.6225	14.89741	15.56682	14.41638	14.42795	14.9592	14.05242	15.56738
1996	TCM87	0.249201	0.760338	0.35977	0.07139	0.596085	0.65024	0.157858	0.025668	0.590561	0.832474	0.407463	0.910675
1996	QCM_FLR	-10.42864	-10.23423	-10.23524	-10.16125	-10.79765	-10.7675	-10.6159	-10.19003	-10.89767	-11.76986	-10.70743	-10.61657
1996	FLR	14.77156	15.73278	15.99937	15.15122	15.6444	14.91814	15.58439	14.44409	14.44094	14.98111	14.08013	15.58038
1997	TCM87	0.528273	0.00995	0.335043	-0.191161	0.695644	0.690143	0.358374	0.178146	0.483043	0.875885	0.522359	0.909468
1997	QCM_FLR	-10.32009	-9.960956	-10.25067	-10.28505	-10.78882	-10.73029	-10.48983	-10.22183	-10.87255	-11.91702	-10.78638	-10.5713
1997	FLR	14.78041	15.73888	16.01425	15.16549	15.6683	14.9417	15.60114	14.47542	14.45301	15.00501	14.11146	15.59244
1998	TCM87	0.385262	0.413433	0.524729	0.175633	0.744315	0.607044	0.510426	0.574364	0.617885	0.809151	0.828115	1.053615
1998	QCM_FLR	-10.47149	-10.05141	-10.4248	-10.4753	-10.83441	-10.90459	-10.71362	-10.26044	-10.98847	-11.91034	-10.78333	-10.41553
1998	FLR	14.79058	15.74669	16.03036	15.1816	15.69627	14.96628	15.62199	14.50829	14.46986	15.03297	14.14433	15.60929
1999	TCM87	-0.357674	0.32573	-0.375693	-0.036332	-0.640274	-0.603769	-0.41871	-0.502592	-0.576051	-0.82022	-0.599386	-0.945073
1999	QCM_FLR	10.5712	9.960255	10.44113	10.47538	10.90767	10.88557	10.76356	10.30853	10.88778	12.00961	10.78357	10.69796
1999	FLR	-14.80814	-15.7567	-16.04907	-15.20068	-15.72808	-14.99202	-15.64769	-14.55063	-14.49341	-15.06479	-14.18667	-15.63284
2000	TCM87	-0.209487	-0.500875	0.370183	0.173953	0.585005	0.626473	0.235072	0.237441	0.323532	0.661657	0.157004	0.856116
2000	QCM_FLR	-10.64719	-9.928819	-10.38156	-10.45832	-10.87819	-10.97466	-10.67225	-10.32453	-10.89739	-11.73493	-10.80875	-10.6644
2000	FLR	14.82306	15.76907	16.06954	15.22189	15.76349	15.01802	15.67919	14.59011	14.51777	15.10019	14.22614	15.65721
2001	TCM87	0.731406	0.951272	0.576051	0.491031	0.907855	0.963937	0.452985	1.003202	1.0936	1.363026	0.74479	0.817133
2001	QCM_FLR	-10.75139	-10.03607	-10.51336	-10.54833	-10.92828	-11.03404	-10.86342	-10.44685	-10.81949	-11.73978	-10.91398	-10.69869
2001	FLR	14.84233	15.78239	16.08961	15.2449	15.79681	15.04719	15.70677	14.6275	14.54296	15.13352	14.26353	15.6824
2002	TCM87	0.274597	0.290428	0.260825	0.303063	0.662688	0.824175	0.306749	0.540579	0.836381	1.101608	0.853564	0.605408
2002	QCM_FLR	-10.69804	-9.993283	-10.3539	-10.51929	-10.95871	-11.03534	-10.62712	-10.39477	-11.01604	-11.64437	-10.9786	-10.73535
2002	FLR	14.86432	15.79755	16.10825	15.26372	15.82963	15.0726	15.73421	14.66104	14.56744	15.16634	14.29707	15.70687
2003	TCM87	1.125579	0.783445	0.50742	0.407463	0.793897	0.764537	0.682592	0.541161	0.463734	1.20147	0.724646	0.72222
2003	QCM_FLR	-10.81744	-10.1338	-10.46123	-10.54033	-10.94377	-11.05512	-10.73289	-10.43014	-11.01381	-11.70079	-10.98742	-10.85435
2003	FLR	14.87915	15.81076	16.124	15.28423	15.8558	15.09277	15.75895	14.68954	14.58792	15.1925	14.32557	15.72736
2004	TCM87	0.826366	0.740508	0.386622	0.363948	0.710004	0.814479	0.650761	0.490419	0.78982	1.18142	0.762207	0.394067
2004	QCM_FLR	-10.95466	-10.09444	-10.51966	-10.58474	-10.97447	-11.05178	-10.85089	-10.47832	-11.07644	-11.69623	-11.01532	-10.84808
2004	FLR	14.8915	15.82207	16.13839	15.30039	15.88185	15.11195	15.78199	14.71552	14.60498	15.21855	14.35156	15.74441
2005	TCM87	0.592774	0.527093	0.255417	0.180653	0.463734	0.789366	0.541161	0.444045	0.519984	0.941569	0.456792	0.432432
2005	QCM_FLR	-10.98257	-10.26062	-10.56394	-10.64246	-10.98874	-11.04146	-10.96842	-10.46439	-11.03032	-11.68515	-11.05266	-10.82296
2005	FLR	14.90435	15.83166	16.15338	15.31553	15.90631	15.13114	15.80292	14.74137	14.62178	15.24301	14.37741	15.76122
2006	TCM87	0.993622	0.35347	0.404131	0.408128	1.02029	0.916291	0.787548	0.463734	1.059178	1.178039	1.137512	0.795704
2006	QCM_FLR	-11.02975	-10.27795	-10.52172	-10.61187	-11.00399	-11.10895	-11.03871	-10.49775	-11.02842	-11.83787	-11.08461	-10.78475
2006	FLR	14.92068	15.84244	16.17045	15.33077	15.93231	15.15151	15.82449	14.7725	14.63929	15.26902	14.40853	15.77872
2007	TCM87	0.947789	0.405465	0.552159	0.579418	0.841998	0.852712	0.614104	0.594983	1.112186	1.178963	1.042042	0.792993
2007	QCM_FLR	-10.95062	-10.22291	-10.57512	-10.66478	-11.02575	-11.14991	-11.02351	-10.57283	-10.9986	-11.84828	-11.14366	-10.8093
2007	FLR	14.93262	15.85366	16.18633	15.34587	15.95991	15.1722	15.84616	14.80524	14.65694	15.29661	14.44127	15.79638
2008	TCM87	0.863312	0.539413	0.779325	0.496524	0.636577	0.909065	0.30822	0.239017	0.279146	1.082483	1.0431	0.923068
2008	QCM_FLR	-10.97875	-10.23502	-10.54087	-10.56937	-10.98552	-11.13943	-10.98381	-10.51688	-10.95221	-11.88835	-11.1648	-10.83484
2008	FLR	14.946	15.86429	16.20345	15.36096	15.98527	15.19212	15.87062	14.83697	14.67404	15.32198	14.473	15.81347
2009	TCM87	1.102272	0.518198	0.387301	0.436318	1.070213	1.057443	0.848012	0.623261	1.21075	1.154047	1.091588	0.718815
2009	QCM_FLR	-11.06186	-10.26981	-10.53377	-10.60598	-11.07528	-11.17901	-10.98755	-10.53441	-11.04401	-11.92348	-11.15915	-10.84407
2009	FLR	14.95814	15.87473	16.21753	15.37525	16.00654	15.20937	15.88914	14.86197	14.68849	15.34324	14.49801	15.82793

Table F8

Data: Equation for electric generator distribution tariffs or markups.

Author: Ernest Zampelli, SAIC, 2008.

Source: The original source for the natural gas prices to electric generators used with city gate prices to calculate markups was the *Electric Power Monthly*, DOE/EIA-0226. The original source for the rest of the data used was the *Natural Gas Monthly*, DOE/EIA-0130. State level city gate and electric generator prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM and 16 NGTDM/EMM regions, respectively) prices. The quantity-weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. The consumption data were generated within the historical routines in the NEMS system based on state level data from the original source and therefore may differ from the original source.

Variables:

$MARKUP_{r,t}$ = electric generator distributor tariff (or markup) in region r, year t (1987 dollars per Mcf) [UDTAR_SF]

$QELEC_{r,t}$ = electric generator consumption of natural gas [sum of BASUQTY_SF and BASUQTY_SI]

REG_r = 1, if observation is in region r, =0 otherwise

$\beta_{0.r}$ = coefficient on REGr [PELREG20 or PELREG25 equivalent to the product of REGr and β0r]

β_0, β_1 = Estimated parameters

ρ = autocorrelation coefficient

r = NGTDM/EMM region

t = year

n = season (1=peak, 2=off-peak)

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and/or in the model code.]

Derivation: The equation used for the peak and off-peak electric markups was estimated using panel data for the 16 EMM regions over the 1990 to 2009 time period and two periods. The equations were estimated in linear form allowing for region and period-specific intercepts and with corrections for cross sectional heteroscedasticity and first order serial correlation using EViews. Because the reported point estimates of the parameters yielded projections of the electric generator distributor tariffs that were considered inconsistent with analyst's expectations (i.e., that did not align well with more recent historical levels), the constant term in each equation was increased by one half of a standard deviation of the error, well within the 95% confidence interval limits for the parameters.

$$\mathrm{MARKUP}_{n,r,t} = \beta_{0,n} + \sum_r \beta_{0,n,r}\mathrm{REG}_r + \beta_{1,n}\mathrm{QELEC}_{n,r,t} + \rho * \mathrm{MARKUP}_{n,r,t-1}$$
$$- \rho_n * (\beta_{0,n} + \sum_r \beta_{0,n,r}\mathrm{REG}_r + \beta_{1,n}\mathrm{QELEC}_{n,r,t-1})$$

Regression Diagnostics and Parameter Estimates

This table reports the results of the estimation of the electric generator tariff equation allowing for different intercepts for each region/peak and off-peak period pairing.

Dependent Variable: TEU87
Method: Least Squares
Date: 08/03/10 Time: 08:58
Sample (adjusted): 2 640
Included observations: 639 after adjustments
Convergence achieved after 6 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=6)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.153777	0.059859	-2.569001	0.0104
R1N1	-0.569051	0.187530	-3.034454	0.0025
R1N2	-1.377838	0.165891	-8.305701	0.0000
R2N2	-0.836857	0.142380	-5.877619	0.0000
R4N1	-0.993607	0.123113	-8.070659	0.0000
R4N2	-0.966333	0.122853	-7.865788	0.0000
R5N2	-0.553732	0.118913	-4.656614	0.0000
R6N2	-0.549285	0.066117	-8.307780	0.0000
R7N2	-0.495265	0.150436	-3.292203	0.0011
R9N2	-0.349100	0.143640	-2.430379	0.0154
R10N1	-0.453206	0.099193	-4.568931	0.0000
R10N2	-0.625117	0.089210	-7.007262	0.0000
R11N1	-0.553142	0.115808	-4.776368	0.0000
R11N2	-1.148493	0.338392	-3.393968	0.0007
QELEC	7.04E-07	2.61E-07	2.703306	0.0071
AR(1), ρ	0.281378	0.048877	5.756867	0.0000

R-squared	0.337021	Mean dependent var	-0.341534
Adjusted R-squared	0.321059	S.D. dependent var	0.704578
S.E. of regression	0.580558	Akaike info criterion	1.775065
Sum squared resid	209.9805	Schwarz criterion	1.886738
Log likelihood	-551.1334	Hannan-Quinn criter.	1.818414
F-statistic	21.11324	Durbin-Watson stat	2.010879
Prob(F-statistic)	0.000000		

Data used for estimation

YEAR	REG	TEU87	QELEC	TEU87	QELEC	REG	TEU87	QELEC	TEU87	QELEC
		peak	peak	off-peak	off-peak		peak	peak	off-peak	off-peak
1990	1	-0.373	5477.792	-0.689	78029.21	9	0.202	112.733	-0.07	733.267
1991	1	-0.285	10403.05	-0.948	90079.95	9	-0.07	88	-1.004	350
1992	1	-0.431	4216.713	-0.879	124801.3	9	-0.031	85	-0.434	474
1993	1	-0.595	16036.8	-1.384	109778.2	9	-0.079	54	-1.686	1745
1994	1	-0.626	11368.83	-1.836	146989.2	9	0.061	118.826	-1.354	1249.174

YEAR	REG	TEU87	QELEC	TEU87	QELEC	REG	TEU87	QELEC	TEU87	QELEC
1995	1	-0.898	30834.64	-1.78	164613.4	9	0.142	380.87	-0.344	2539.13
1996	1	-0.544	30441.67	-1.507	152519.3	9	-0.009	471.804	-0.227	1934.196
1997	1	-0.647	51998.01	-0.985	152213	9	-0.044	478.75	-0.447	3349.25
1998	1	-0.527	58556.68	-1.476	124108.3	9	0.343	644.785	-0.557	11348.22
1999	1	-2.145	26046.15	-2.22	154448.8	9	-0.129	904	-0.324	10655
2000	1	-2.864	48405.54	-2.915	151491.4	9	-0.248	2628.278	0.356	6823.722
2001	1	-0.25	75437.73	-1.985	192119.3	9	-0.921	655.664	-0.514	6254.336
2002	1	-0.665	106724.8	-1.482	233054.2	9	-0.82	4669.191	-0.453	11638.81
2003	1	-0.218	93391.41	-0.622	249761.6	9	0.321	2993.909	-0.332	6293.09
2004	1	0.075	104596.4	-1.357	248623.6	9	-0.117	1886.401	-0.005	5208.599
2005	1	0.103	96665.48	-0.938	258176.5	9	0.616	5315.032	-0.031	17492.97
2006	1	-1.356	101914.5	-1.654	267822.5	9	-0.905	3080.886	-0.662	15897.11
2007	1	-0.079	103940.7	-1.287	277224.3	9	-0.312	6110.758	-0.597	20556.24
2008	1	0.252	101929.7	-0.739	250712.3	9	-0.071	4028.149	0.085	9966.851
2009	1	-0.906	113848.8	-1.615	238725.2	9	-1.09	3550.858	-0.92	8518.142
1990	2	-0.091	56008.69	-0.827	254571.3	10	-0.78	11836.17	-0.971	58827.83
1991	2	-0.157	64743.73	-0.898	267021.3	10	-0.812	15655.99	-1.021	51891.01
1992	2	-0.277	86805.72	-0.846	297436.3	10	-0.931	16384.83	-0.943	42633.17
1993	2	-0.302	83314.7	-0.87	308035.3	10	-0.715	8031.323	-0.744	38079.68
1994	2	-0.503	70013.87	-0.815	393282.2	10	-0.56	16516.63	-0.983	71653.38
1995	2	-0.444	134962.2	-0.675	487430.7	10	-0.607	30614.88	-0.86	89503.12
1996	2	0.171	62217.58	-0.622	411604.4	10	0.692	14569.8	-0.618	76325.2
1997	2	-0.502	111473	-1.339	456865	10	-0.684	14076	-0.592	70928
1998	2	-0.397	108447	-0.742	433440	10	-0.615	15754.85	-0.793	88350.15
1999	2	-0.284	108384.3	-0.864	496415.8	10	-0.541	28160.57	-0.566	103466.4
2000	2	0.037	120397.1	-0.692	408934.9	10	-0.559	34598.51	-0.28	108258.5
2001	2	0.566	114874.5	-0.896	393543.5	10	-1.737	40322.03	-1.047	177977
2002	2	-0.56	140725.3	-0.283	435593.6	10	-0.807	79041.83	-0.438	197026.2
2003	2	0.591	111812	-0.135	320290	10	0.211	58740.21	-0.426	123469.8
2004	2	0.17	121153.9	-0.097	354346.2	10	-0.434	59686.33	-0.333	164801.7
2005	2	0.356	116582	0.151	393216	10	0.674	56009.41	0.03	184339.6
2006	2	-0.916	137123.6	-1.023	482526.4	10	-1.223	46339.27	-0.933	239106.8
2007	2	-0.366	171300.2	-0.902	538288.8	10	-0.589	82203.64	-0.851	276528.3
2008	2	0.118	189873.8	-0.029	520375.2	10	-0.307	95446.84	-0.201	236164.2
2009	2	-1.209	212035.5	-1.426	544876.5	10	-1.263	121736.6	-1.046	292033.4
1990	3	0.477	150	-0.356	1103	11	-0.5	383955.5	-0.588	1244416
1991	3	-0.539	453	-0.68	2784	11	-0.471	381862.6	-0.474	1224830
1992	3	-0.597	933	-0.9	2023	11	-0.4	396487	-0.439	1151983
1993	3	-0.491	1267	0.237	1469	11	-0.39	381623.1	-0.41	1254746
1994	3	1.015	845.443	0.864	2122.557	11	-0.384	386224	-0.37	1266091
1995	3	-0.197	851.772	-0.584	6606.229	11	-0.555	426659.9	-0.507	1298862
1996	3	0.336	446.384	-0.27	2455.616	11	-0.183	387316.8	-0.302	1250172
1997	3	0.397	390	-0.063	3100	11	-0.628	378754.8	-0.27	1292336
1998	3	0.447	904.887	0.156	7075.113	11	-0.241	393644.6	-0.113	1588856
1999	3	0.282	2043.821	-0.556	9343.18	11	-0.407	449100.1	-0.214	1535106
2000	3	-0.057	2424.521	0.069	7697.479	11	-0.173	505656.9	-0.106	1587056
2001	3	1.586	1313.623	2.199	9230.377	11	-0.469	473726.6	-0.291	1475389
2002	3	-0.291	5156.494	-0.457	17565.51	11	-0.5	527764.5	-0.314	1583531
2003	3	-0.134	5862.449	0.086	12911.55	11	0.169	520349.9	0.035	1422995
2004	3	-0.037	5929.066	-0.26	12328.93	11	-0.229	496203.2	-0.024	1383611
2005	3	0.204	6165.703	-0.088	21775.3	11	0.066	497927.9	-0.046	1544522
2006	3	-0.931	4535.418	-0.126	18648.58	11	-0.645	474470.1	-0.286	1534773
2007	3	-0.287	9500.535	-0.174	27791.47	11	-0.524	541641.6	-0.532	1506612
2008	3	0.267	8165.851	1.186	15327.15	11	-0.454	571748.9	-0.527	1451966

YEAR	REG	TEU87	QELEC	TEU87	QELEC	REG	TEU87	QELEC	TEU87	QELEC
2009	3	-0.925	12502.88	-1.185	25454.13	11	-1.02	550137.3	-0.832	1434106
1990	4	-1.817	31429.56	-1.347	72129.44	12	-0.595	108.33	-0.957	376.67
1991	4	-1.348	31578.48	-1.253	77733.52	12	0.711	74.782	1.56	268.218
1992	4	-1.418	44851.64	-1.497	68893.36	12	1.405	51.828	-0.004	250.172
1993	4	-1.241	35502.96	-1.283	87438.03	12	0.845	112.683	0.455	242.317
1994	4	-0.907	45192.25	-1.022	104732.8	12	-0.713	189.751	-0.878	571.249
1995	4	-1.128	47723.8	-1.258	132765.2	12	5.098	93.277	1.118	422.723
1996	4	-1.342	41181.18	-1.264	136386.8	12	3.806	267.156	1.572	471.844
1997	4	-1.893	58116.89	-1.709	149975.1	12	-1.3	713.689	-0.673	1580.311
1998	4	-1.426	57722.75	-1.106	185009.2	12	-0.003	834	-1.099	1726
1999	4	-1.017	56206.06	-1.275	181599.9	12	-1.421	661.7	-1.291	1543.3
2000	4	-0.795	62974.71	-0.843	154818.3	12	-1.468	858	-1.035	2886
2001	4	-1.38	55546.81	-0.777	164441.2	12	-0.705	2966.774	-0.578	10398.23
2002	4	-0.447	64369.93	-0.624	219275	12	0.762	1841.396	0.58	4757.604
2003	4	-0.951	58171.08	-0.766	128116.9	12	-0.093	3115.147	-0.2	9223.853
2004	4	-1.009	67560.77	-1.245	140486.2	12	-0.73	3432.394	-0.513	9186.606
2005	4	-1.006	62452.09	-1.464	220560.9	12	-0.394	3310.012	-0.31	8903.987
2006	4	-1.683	43653.99	-0.841	179495	12	-0.645	2908.668	-0.985	8073.332
2007	4	-0.72	70883.59	-0.594	207352.4	12	-0.109	4028.414	-0.17	11499.59
2008	4	-0.447	70728.65	0.307	132756.4	12	0.074	4134.663	0.213	9996.337
2009	4	-0.718	63267.38	-1.036	128803.6	12	-0.835	3748.62	-0.598	9380.38
1990	5	-0.591	6513.661	-0.868	37663.33	13	-0.406	7475.622	-1.168	30674.38
1991	5	-0.577	8386.246	-0.945	54605.75	13	-0.725	8442.727	-1.35	32877.27
1992	5	-0.477	6564.392	-0.855	19551.61	13	-0.779	11631.35	-1.39	41860.65
1993	5	-0.404	5430.949	-0.708	31682.05	13	-0.202	16816.29	-0.642	41179.71
1994	5	-0.379	6607.164	-1.018	37455.84	13	-0.624	16133.88	-1.112	66494.13
1995	5	-0.49	9284.483	-0.854	48442.52	13	-0.717	25685.17	-0.801	67311.83
1996	5	-0.145	6701.926	-0.869	33308.07	13	-0.188	22187.69	-0.468	78930.31
1997	5	-0.485	7062.148	-1.058	40882.85	13	-0.467	22608.37	-0.311	83926.64
1998	5	-0.275	6673.499	-0.839	73116.5	13	-0.385	28588.31	0.006	94087.7
1999	5	-0.392	11064.86	-0.741	67943.15	13	-0.072	35234.71	-0.007	102074.3
2000	5	-0.33	14452.84	-0.533	73293.16	13	1.265	53316.27	0.455	141533.7
2001	5	-0.658	12855.91	-0.609	68365.09	13	1.211	71984.5	1.291	137618.5
2002	5	-0.502	14525.6	-0.627	61418.4	13	0.473	56705.46	0.332	146509.5
2003	5	0.365	12441.34	-0.24	51685.66	13	0.415	52597.99	0.28	155741
2004	5	0.111	15715.84	-0.398	45414.16	13	-0.132	62488.94	0.094	167248.1
2005	5	0.574	22234.67	-0.68	82644.33	13	0.01	68457.95	0.123	184153
2006	5	-0.07	16733.13	-0.368	93896.87	13	-0.452	76476.9	-0.827	212270.1
2007	5	0.162	36287.14	-0.307	106214.9	13	-0.652	91240.94	-0.624	260458.1
2008	5	0.254	40233.62	-0.079	81822.38	13	-0.092	100212.7	0.03	242283.3
2009	5	-0.488	30968.19	-0.602	68794.81	13	-0.614	101870	-0.415	254915
1990	6	0.123	5736.463	-0.57	45691.54	14	-0.12	12451.51	-0.552	37300.48
1991	6	-0.259	9603.718	-0.824	55953.28	14	-0.39	10503.82	-0.595	40932.18
1992	6	-0.1	13896.39	-0.568	40156.62	14	-0.093	11060.75	-0.151	42418.25
1993	6	-0.168	18359.31	-0.714	46145.68	14	0.047	11955.11	-0.095	36309.89
1994	6	-0.247	18000.7	-0.969	60320.31	14	-0.143	13658.88	-0.164	44792.13
1995	6	-0.142	25663.08	-0.677	78174.92	14	-0.125	13662.47	-0.176	40548.53
1996	6	-0.021	14490.55	-0.611	57460.45	14	0.394	11768.99	0.121	45934.01
1997	6	-0.455	11760.21	-0.704	48107.79	14	0.084	12934.19	-0.122	54012.81
1998	6	-0.031	10607.77	-0.703	82748.23	14	0.076	18095.38	-0.132	69705.62
1999	6	-0.088	18558	-0.702	88756	14	-0.042	22906.24	-0.124	74796.77
2000	6	-0.661	18429.81	-0.196	77524.2	14	0.368	33129.53	0.148	109635.5
2001	6	1.04	11727.8	-0.54	83846.2	14	0.489	49709.35	-0.107	128357.6
2002	6	-0.542	31719.6	-1.034	113421.4	14	0.286	50972.55	-0.266	131697.5

YEAR	REG	TEU87	QELEC	TEU87	QELEC	REG	TEU87	QELEC	TEU87	QELEC
2003	6	0.025	22153.38	-0.48	65724.62	14	0.355	52509.88	0.372	155480.1
2004	6	-0.342	31824.06	-0.621	96166.94	14	0.239	73750.1	0.265	197387.9
2005	6	-0.163	42401.81	-0.379	132210.2	14	0.716	70105.91	0.66	188586.1
2006	6	-1.163	38068.46	-0.523	135358.5	14	-0.245	80424.6	-0.312	223227.4
2007	6	-0.056	50933.98	-0.522	170925	14	-0.019	88519	-0.567	252688
2008	6	0.475	47926.71	-0.042	144152.3	14	-0.166	103157.1	0.523	249401.9
2009	6	-1.173	60839.04	-0.951	177359	14	-0.482	95551.13	-0.231	239102.9
1990	7	0.373	94	-0.127	1838	15	-0.398	2163.144	-0.413	5411.857
1991	7	0.18	86	-0.214	752	15	-0.111	2385.528	-0.415	10360.47
1992	7	0.599	40	-0.404	1122	15	-0.184	6807.541	0.497	19222.46
1993	7	0.601	112.963	-0.408	2913.037	15	0.499	26265.15	-0.027	18996.85
1994	7	0.485	268.321	-0.153	1070.679	15	-0.333	26457.18	-0.207	42886.82
1995	7	1.584	368.214	-0.26	10727.79	15	-0.285	17894.08	-0.113	41866.93
1996	7	1.371	208.809	-0.706	5566.191	15	0.58	1662.173	-0.161	66420.83
1997	7	0.181	323.943	-0.941	16729.06	15	0.104	7462.426	0.902	44431.57
1998	7	-1.064	845	-0.463	32505	15	-0.372	16440.47	-0.323	76776.53
1999	7	-0.867	683	-1.1	31822	15	-0.098	12471.85	-0.158	69827.15
2000	7	0.814	676	-0.777	41357	15	0.166	30435.15	0.56	113414.9
2001	7	-0.394	1813.314	-1.357	32851.69	15	0.213	55816.64	0.531	112908.4
2002	7	-0.472	12366.93	-0.961	44221.07	15	-0.439	30135.98	-0.949	65269.01
2003	7	-0.114	8131.998	-0.605	24126	15	-0.518	41637.16	-1.075	90642.84
2004	7	-0.437	11419.18	-0.718	34506.82	15	-0.675	46265.81	-0.82	108536.2
2005	7	0.062	17548.92	-0.107	54718.08	15	-0.387	48284.78	-0.701	105522.2
2006	7	-1.522	20942.52	-0.854	74464.48	15	-1.054	36728.14	-1.325	97256.86
2007	7	-0.527	27945.63	-0.963	93780.37	15	-0.7	45077.4	-0.962	113719.6
2008	7	0.218	24032.35	-0.327	72283.65	15	-0.536	62191.23	-0.708	129025.8
2009	7	-1.494	36520.59	-1.208	106465.4	15	-1.093	61018.65	-1.443	133252.4
1990	8	-0.111	53532.49	-0.081	135631.5	16	0.519	154426.4	0.106	474358.6
1991	8	-0.347	57488.14	-0.233	143844.9	16	0.314	200566.8	0.049	427968.1
1992	8	-0.559	54243.96	-0.149	149075	16	0.129	227147.9	0.029	535783.1
1993	8	-0.41	47776.24	-0.304	140451.8	16	0.261	244498.6	0.09	428566.4
1994	8	-0.538	53104.2	-0.412	158386.8	16	-0.027	238089.7	0.013	572584.3
1995	8	-0.384	80269.09	-0.369	289028.9	16	0.403	181126.9	0.103	421776.1
1996	8	-0.203	70158.84	-0.441	267108.2	16	0.446	116542	0.08	408493
1997	8	-1.335	88892.73	-0.917	249964.3	16	0.344	129870	0.036	465952
1998	8	-0.996	80991.75	-0.831	242778.3	16	0.378	206154	0.294	442932
1999	8	-0.436	83337	-0.25	282249	16	0.305	279871.4	0.035	443299.6
2000	8	-0.699	109654.3	-0.233	254590.7	16	3.086	234992	0.621	658384
2001	8	-0.608	88541.95	-0.013	285769.1	16	1.745	313453.9	1.712	659873.1
2002	8	0.223	114050.8	0.133	407817.2	16	0.606	229522.8	0.335	497104.2
2003	8	0.241	134894.4	0.056	400204.6	16	0.438	222017.6	0.166	483325.4
2004	8	-0.203	145665.3	0.002	440175.8	16	0.003	230285.1	-0.041	540231.9
2005	8	-0.598	153085.3	-0.367	477324.7	16	0.559	216351.5	-0.172	472817.5
2006	8	-0.21	162821.4	0.462	578937.6	16	-0.409	211302.6	0.249	559533.4
2007	8	0.835	177456.6	0.931	595511.4	16	0.046	236827.2	-0.076	597458.9
2008	8	0.396	198930.3	0.309	598335.6	16	0.092	279011.8	0.08	578855.2
2009	8	1.253	232426	1.368	677572	16	0.123	255257.8	0.146	557431.3

Table F9

Data: Equation for natural gas price at the Henry Hub

Author: Eddie Thomas, EI-83, 2008

Source: Annual natural gas wellhead prices and chain-type GDP price deflators data from EIA's *Annual Energy Review 2007*, DOE/EIA-0384(2007), published June 2008. Henry Hub spot price data from EIA's Short-Term Energy Outlook database series NGHHUUS; the annual Henry Hub prices equal the arithmetic average of the monthly data.

Variables:

HHPRICE	=	Henry Hub spot natural gas price (1987 dollars per MMBtu)
EIAPRICE	=	Average U.S. natural gas wellhead price (1987 dollars per Mcf)
HHPRICE_HAT	=	estimated values for Henry Hub price (1987 dollars per MMBtu)
α	=	estimated parameter
α_0	=	constant term
const2	=	constant term

Derivation: Using TSP version 5.0 and annual price data from 1995 through 2007, the first equation was estimated in log-linear form using ordinary least squares. The second equation estimates an adjustment factor that is applied in cases where the value of "y" is predicted from an estimated equation where the dependent variable is the natural log of y. The adjustment is due to the fact that generally predictions of "y" using the first equation only tend to be biased downward.

1) $\ln HHPRICE = \alpha_0 + (\alpha * \ln EIAPRICE)$
2) $HHPRICE = \beta * HHPRICE\_HAT$

Regression Diagnostics and Parameter Estimates

First Equation

Dependent variable: lnHHPRICE
Current sample: 1 to 13
Number of observations: 13

Mean of dep. var.	= 1.00473	LM het. test	= .317007 [.573]
Std. dev. of dep. var.	= .447616	Durbin-Watson	= 2.74129 [<.934]
Sum of squared residuals	= .048856	Jarque-Bera test	= .475878 [.788]
Variance of residuals	= .444143E-02	Ramsey's RESET2	= .103879 [.754]
Std. error of regression	= .066644	F (zero slopes)	= 530.339 [.000]
R-squared	= .979680	Schwarz B.I.C.	= -15.2838
Adjusted R-squared	= .977833	Log likelihood	= 17.8487

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value	Symbol
CONST	.090246	.043801	2.06036	[.064]	α_0
lnEIAPRICE	1.00119	.043475	23.0291	[.000]	α

<u>Second Equation</u>

Dependent variable: HHPRICE
Current sample: 1 to 13
Number of observations: 13

Mean of dep. var.	= 2.98879	LM het. test	= 2.14305 [.143]
Std. dev. of dep. var.	= 1.29996	Durbin-Watson	= 2.97238 [<1.00]
Sum of squared residuals	= .420043	Jarque-Bera test	= .138664 [.933]
Variance of residuals	= .035004	Ramsey's RESET2	= .655186 [.435]
Std. error of regression	= .187092	Schwarz B.I.C.	= -2.58158
R-squared	= .979456	Log likelihood	= 3.86405
Adjusted R-squared	= .979456		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value	Symbol
HHPRICE_HAT	1.00439	.016114	62.3290	[.000]	β

Data used for Estimation:

Year	**Henry Hub Spot Natural Gas Price ($/MMBtu, in 1987 dollars)**	**Average U.S. Wellhead Natural Gas Price ($/Mcf, in 1987 dollars)**
1995	1.34	1.23
1996	2.14	1.70
1997	1.91	1.79
1998	1.58	1.50
1999	1.70	1.65
2000	3.16	2.73
2001	2.83	2.89
2002	2.36	2.09
2003	3.77	3.40
2004	3.95	3.68
2005	5.62	4.79
2006	4.23	4.03
2007	4.26	3.90

Table F10

Data: Lease and plant fuel consumption in Alaska

Author: Margaret Leddy, EIA summer intern

Source: EIA's Petroleum Supply Annual and Natural Gas Annual.

Variables:

LSE_PLT = Lease and plant fuel consumption in Alaska [QALK_LAP_N]
OIL_PROD = Oil production in Alaska (thousand barrels) [OGPRCOAK]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Using EViews and annual price data from 1981 through 2007, the following equation was estimated using ordinary least squares without a constant term:

$$LSE\_PLT_t = \beta_{-1} * LSE\_PLT_{t-1} + \beta_1 * OIL\_PROD_t$$

The intent was to find an equation that demonstrated similar characteristics to the projection by the Alaska Department of Natural Resources in their "Alaska Oil and Gas Report."

Regression Diagnostics and Parameter Estimates

Dependent Variable: LSE_PLT
Method: Least Squares
Date: 07/24/09 Time: 17:34
Sample (adjusted): 1981 2007
Included observations: 27 after adjustments

	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
OIL_PROD	0.038873	0.015357	2.531280	0.0180	β_1
LSE_PLT_PREV	0.943884	0.037324	25.28876	0.0000	β_{-1}

R-squared	0.911327	Mean dependent var	210731.2
Adjusted R-squared	0.907780	S.D. dependent var	86703.97
S.E. of regression	26329.98	Akaike info criterion	23.26599
Sum squared resid	1.73E+10	Schwarz criterion	23.36198
Log likelihood	-312.0909	Hannan-Quinn criter.	23.29453
Durbin-Watson stat	2.407017		

Data used for Estimation:

Year	oil_prod	lse_plt	Year	oil_prod	lse_plt	Year	oil_prod	lse_plt
1981	587337	15249	1990	647309	193875	1999	383199	265504.375
1982	618910	94232	1991	656349	223194.366	2000	355199	269177.988
1983	625527	97828	1992	627322	234716.225	2001	351411	271448.841
1984	630401	111069	1993	577495	237701.556	2002	359335	285476.659
1985	666233	64148	1994	568951	238156.064	2003	355582	300463.487
1986	681310	72686	1995	541654	292810.594	2004	332465	281546.298
1987	715955	116682	1996	509999	295833.863	2005	315420	303215.128
1988	738143	153670	1997	472949	271284.345	2006	270486	257091.267
1989	683979	192239	1998	428850	281871.556	2007	263595	268571.098

Table F11

Data: Western Canada successful conventional gas wells

Author: Ernie Zampelli, SAIC, 2009

Source: Canadian Association of Petroleum Producers, Statistical Handbook. Undiscovered remaining resource estimates from National Energy Board of Canada.

Variables:

GWELLS = Number of successful new natural gas wells drilled in Western Canada [SUCWELL]

PGAS2000 = Average natural gas wellhead price in Alberta (2000 U.S. dollars per Mcf) [CN_PRC00]

REMAIN = Remaining natural gas undiscovered resources in Western Canada (Bcf) [URRCAN]

DRILLCOSTPERGASWELL2000 = U.S. based proxy for drilling cost per gas well (2000 U.S. dollars) [CST_PRXYLAG]

PR_LAG = Production to reserve ratio last forecast year [CURPRRCAN]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Using TSP version 5.0 and annual price data from 1978 through 2005, the following equation was estimated after taking natural logs of all of the variables and by instrumental variables:

$$\ln GWELLS = \beta_0 + \beta_1 * \ln PGAS2000 + \beta_2 * \ln REMAIN + \beta_3 * \ln DRILLCOSTPERGASWELL2000LAG + \beta_4 * PR\_LAG$$

Regression Diagnostics and Parameter Estimates

```
TSP Program File:  canada10_wells_v1.tsp
TSP Output File:  canada10_wells_v1.out
Data File: canada10.xls

Method of estimation = Instrumental Variable

 Dependent variable: LNGWELLS
 Endogenous variables: LNPGAS2000
 Included exogenous variables: C LNREMAIN PR_LAG LNDRILLCOSTPERGASWELL2000LAG
 Excluded exogenous variables: LNRIGS_AVAIL LNRIGS_ACT LNWOP2000
                               LNWOP2000(-1)
 Current sample:  32 to 59
 Number of observations:  28

        Mean of dep. var. = 8.22053  Adjusted R-squared = .868002
   Std. dev. of dep. var. = .770092       Durbin-Watson = 1.47006 [<.460]
 Sum of squared residuals = 1.81489     F (zero slopes) = 44.8913 [.000]
    Variance of residuals = .078908  F (over-id. rest.) = 3.04299 [.049]
 Std. error of regression = .280906             E'PZ*E = .720351
                R-squared = .887557
```

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value	Symbol
C	-1.85639	10.8399	-.171256	[.864]	β_0
LNPGAS2000	1.09939	.275848	3.98551	[.000]	β_1
LNREMAIN	1.57373	.767550	2.05033	[.040]	β_2
PR_LAG	33.6237	5.95568	5.64564	[.000]	β_3
LNDRILLCOSTPERGASWELL2000LAG	-.860630	.413101	-2.08334	[.037]	β_4

where LNGWELLS is the natural log of the number of successful gas wells drilled, C is the constant term, LNPGAS2000 is the natural log of the natural gas wellhead price in US$2000, LNREMAIN is the natural log of remaining natural gas resources, PR_LAG is the one-year lag of the natural gas production to reserves ratio, and LNDRILLCOSTPERGASWELL2000LAG is the one-year lag of the natural log drilling costs per gas well in US$2000.

Data used for Estimation:

OBS	Year	gwells	pgas2000	Remain	drillcostpergaswell2000
3	1949		0.048973961		
4	1950		0.326113924		
5	1951		0.332526561		
6	1952		0.53466758		
7	1953		0.520772302		
8	1954		0.518522266		
9	1955	168	0.508917468		
10	1956	180	0.506220324		
11	1957	194	0.521861883		
12	1958	200	0.481073325		
13	1959	302	0.452683617		
14	1960	292	0.474693506		487885.5568
15	1961	392	0.533594173		445149.9201
16	1962	331	0.529535218		450150.6792
17	1963	338	0.569702785		423745.2977
18	1964	308	0.58367073	247614.5688	473327.0074
19	1965	320	0.567907929	238537.3503	452030.1753
20	1966	342	0.576547139	236436.2237	577347.2558
21	1967	372	0.562604404	232547.9993	590110.0741
22	1968	478	0.537960863	229480.2528	596222.8555
23	1969	524	0.505967348	224686.5834	590148.7629
24	1970	731	0.518371638	219742.8184	583504.0314
25	1971	838	0.506420538	215141.3928	576188.9938
26	1972	1164	0.514557299	211401.9226	522986.1433
27	1973	1656	0.532790308	210506.5381	487525.511
28	1974	1902	0.791608407	207750.6318	544786.1771
29	1975	2080	1.411738215	207326.7494	689458.4496
30	1976	3304	2.237940881	203831.3434	672641.5564
31	1977	3192	2.599391226	201592.1585	733387.9117
32	1978	3319	2.626329384	196792.3469	817752.475
33	1979	3450	2.710346999	191501.0181	894243.9654
34	1980	4241	3.384567857	185756.1549	992546.6758
35	1981	3206	3.221572826	182757.9141	1181643.803
36	1982	2555	3.213342789	177773.8365	1377862.449
37	1983	1374	3.284911566	175254.2284	932534.8506
38	1984	1866	3.129580432	172207.6619	723979.0112
39	1985	2528	2.783743697	164103.9115	729665.916
40	1986	1298	2.102135277	163082.6472	733903.1579
41	1987	1599	1.70904727	162025.2004	519637.6851
42	1988	2300	1.605152553	161045.0253	608099.7173
43	1989	2313	1.6374231	159296.4045	582756.2503
44	1990	2226	1.616410647	154195.8722	577621.032
45	1991	1645	1.413315563	150493.0434	599894.6047
46	1992	908	1.302240063	147472.6695	493273.1377
47	1993	3327	1.450352061	144605.8153	589678.7771
48	1994	5333	1.51784337	141039.5975	592881.5963
49	1995	3325	1.094686059	137038.8014	683668.8164
50	1996	3664	1.255799796	130554.9327	656352.5551
51	1997	4820	1.46778215	128082.3795	763619.5946
52	1998	4955	1.340424158	126038.0859	845430.7986
53	1999	7005	1.702885108	122364.2737	815784.5261
54	2000	9034	3.139760843	117371.83	756939
55	2001	10693	3.517434005	112428.7004	875486.0887
56	2002	9011	2.374637309	105719.0529	951999.7696
57	2003	12911	4.216469412	100440.0085	1039434.608
58	2004	15041	4.506654918	95800	1568071.111
59	2005	15895	6.175733625	89650.7047	1324919.051
60	2006	13850	3.555109614	82089.6695	1161087.791
61	2007	9626	5.155666777	75854.5886	3260771.516
62	2008	8104	6.102395678	69930.7064	

Table F12

Data: Western Canada conventional natural gas finding rate

Author: Ernie Zampelli, SAIC, 2009

Source: Canadian Association of Petroleum Producers, Statistical Handbook. Undiscovered remaining resource estimates from National Energy Board of Canada.

Variables:

FR = Natural gas proved reserves added per successful natural gas well in Western Canada (Bcf/well) [FRCAN]

REMAIN = Remaining natural gas undiscovered resources in Western Canada (Bcf) [URRCAN]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The equation to project the average natural gas finding rate in Western Canada was estimated for the time period 1965-2007 using TSP version 5.0 and aggregated reserves and production data for the provinces in Western Canada. Natural logs were taken of all data before the estimation was performed. The following equation was estimated with correction for first-order serial correlation:

$$\ln FR_t = \beta_0 + \beta_1 * \ln REMAIN_t + \rho * \ln FR_{t-1} - \rho * (\beta_0 + \beta_1 * \ln REMAIN_{t-1})$$

Regression Diagnostics and Parameter Estimates

```
TSP Program File:  canada10_findrate_v1.tsp
TSP Output File:  canada10_findrate_v1.out
Data File:  canada10.xls

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

 Objective function:  Exact ML (keep first obs.)

 CONVERGENCE ACHIEVED AFTER   6 ITERATIONS

 Dependent variable: LNFR
 Current sample:  19 to 61
 Number of observations:  43
        Mean of dep. var. = .258333           R-squared = .523925
   Std. dev. of dep. var. = 1.01511  Adjusted R-squared = .500121
 Sum of squared residuals = 20.6112       Durbin-Watson = 2.19910
    Variance of residuals = .515280      Schwarz B.I.C. = 50.8486
 Std. error of regression = .717830      Log likelihood = -45.2068

                          Standard
 Parameter  Estimate        Error       t-statistic   P-value     Symbol
 C          -25.3204       6.81740      -3.71409      [.000]      β0
 LNREMAIN   2.13897        .569561      3.75547       [.000]      β1
 RHO (ρ)    .428588        .139084      3.08150       [.002]      ρ
```

Data used for Estimation:

OBS	Year	fr	remain
17	1963	9.28880858	
18	1964	29.47148864	247614.5688
19	1965	6.566020625	238537.3503
20	1966	11.36907719	236436.2237
21	1967	8.246630376	232547.9993
22	1968	10.02859707	229480.2528
23	1969	9.434666031	224686.5834
24	1970	6.294699863	219742.8184
25	1971	4.46237494	215141.3928
26	1972	0.76923067	211401.9226
27	1973	1.664194626	210506.5381
28	1974	0.222861409	207750.6318
29	1975	1.680483654	207326.7494
30	1976	0.677719401	203831.3434
31	1977	1.503700376	201592.1585
32	1978	1.594253932	196792.3469
33	1979	1.665177739	191501.0181
34	1980	0.706965527	185756.1549
35	1981	1.554609357	182757.9141
36	1982	0.986147984	177773.8365
37	1983	2.217297307	175254.2284
38	1984	4.342845874	172207.6619
39	1985	0.403981131	164103.9115
40	1986	0.81467396	163082.6472
41	1987	0.612992558	162025.2004
42	1988	0.760269913	161045.0253
43	1989	2.205158798	159296.4045
44	1990	1.663445103	154195.8722
45	1991	1.836093556	150493.0434
46	1992	3.157328414	147472.6695
47	1993	1.071901954	144605.8153
48	1994	0.750196156	141039.5975
49	1995	1.950035699	137038.8014
50	1996	0.674823472	130554.9327
51	1997	0.424127303	128082.3795
52	1998	0.741435358	126038.0859
53	1999	0.712697173	122364.2737
54	2000	0.547169537	117371.83
55	2001	0.627480361	112428.7004
56	2002	0.585844457	105719.0529
57	2003	0.35938413	100440.0085
58	2004	0.408835536	95800
59	2005	0.475686392	89650.7047
60	2006	0.450186347	82089.6695
61	2007	0.615404342	75854.5886
62	2008		69930.7064

Table F13

Data: Western Canada production-to-reserves ratio

Author: Ernie Zampelli, SAIC, 2009

Source: Canadian Association of Petroleum Producers, Statistical Handbook.

Variables:

PR = Natural gas production-to-reserve ratio in Western Canada [PRRATCAN]

GWELLS = Number of successful new natural gas wells drilled in Western Canada [SUCWELL}

RES_ADD_PER_WELL = Proved natural gas reserves added per successful natural gas well in Western Canada (Bcf/well) [FRCAN]

YEAR = Calendar year [RLYR]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The equation was estimated using TSP version 5.0 for the period from 1978 to 2007 using aggregated data in natural log form (with the exception of YEAR) for the provinces of Western Canada. Because the PR ratio is bounded between zero and one, the dependent variable was measured in logistic form, as follows:

$$\ln\left(\frac{PR_t}{1-PR_t}\right) = \beta_0 + \beta_1 * \ln GWELLS_t + \beta_2 * \ln RES\_ADD\_PER\_WELL_t + \beta_3 * YEAR$$
$$+ \rho * \ln\left(\frac{PR_{t-1}}{1-PR_{t-1}}\right)$$
$$- \rho * (\beta_0 + \beta_1 * \ln GWELLS_t + \beta_2 * \ln RES\_ADD\_PER\_WELL_t + \beta_3 * YEAR)$$

Regression Diagnostics and Parameter Estimates

```
TSP Program File:  canada10_pr_v1.tsp
TSP Output File:  canada10_pr_v1.out
Data File:  canada10.xls

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

 Objective function:  Exact ML (keep first obs.)

 CONVERGENCE ACHIEVED AFTER   7 ITERATIONS

 Dependent variable: LOGISTIC
 Current sample:  32 to 61
 Number of observations:  30
```

```
      Mean of dep. var. = -2.68213            R-squared = .986473
  Std. dev. of dep. var. = .479351     Adjusted R-squared = .984308
Sum of squared residuals = .090398          Durbin-Watson = 1.29483
   Variance of residuals = .361591E-02      Schwarz B.I.C. = -35.3745
Std. error of regression = .060132         Log likelihood = 43.8775
```

Parameter	Estimate	Standard Error	t-statistic	P-value	Symbol
C	-72.1364	13.7385	-5.25069	[.000]	β_0
LNGWELLS	.117911	.032053	3.67858	[.000]	β_1
LNRES_ADD_PER_WELL	.041469	.017819	2.32723	[.020]	β_2
YEAR	.034370	.690795E-02	4.97536	[.000]	β_3
RHO (ρ)	.916835	.061397	14.9329	[.000]	ρ

Data used for Estimation:

OBS	Year	pr	gwells	res_add_per_well
9	1955		168	
10	1956		180	
11	1957		194	
12	1958		200	
13	1959		302	
14	1960		292	
15	1961		392	
16	1962		331	
17	1963	0.023779341	338	9.28880858
18	1964	0.024979017	308	29.47148864
19	1965	0.022612325	320	6.566020625
20	1966	0.02372014	342	11.36907719
21	1967	0.024985242	372	8.246630376
22	1968	0.027431524	478	10.02859707
23	1969	0.030312333	524	9.434666031
24	1970	0.032625343	731	6.294699863
25	1971	0.034308623	838	4.46237494
26	1972	0.037697554	1164	0.76923067
27	1973	0.041418124	1656	1.664194626
28	1974	0.040851176	1902	0.222861409
29	1975	0.042823468	2080	1.680483654
30	1976	0.042727689	3304	0.677719401
31	1977	0.04464118	3192	1.503700376
32	1978	0.04178307	3319	1.594253932
33	1979	0.042644059	3450	1.665177739
34	1980	0.037495598	4241	0.706965527
35	1981	0.036757207	3206	1.554609357
36	1982	0.036329357	2555	0.986147984
37	1983	0.034484267	1374	2.217297307
38	1984	0.03717602	1866	4.342845874
39	1985	0.038172848	2528	0.403981131
40	1986	0.035340517	1298	0.81467396
41	1987	0.039250307	1599	0.612992558
42	1988	0.046730172	2300	0.760269913
43	1989	0.051076089	2313	2.205158798
44	1990	0.050410254	2226	1.663445103
45	1991	0.054586093	1645	1.836093556
46	1992	0.060679876	908	3.157328414
47	1993	0.068904777	3327	1.071901954
48	1994	0.075709817	5333	0.750196156
49	1995	0.080323276	3325	1.950035699
50	1996	0.082543421	3664	0.674823472
51	1997	0.087979875	4820	0.424127303
52	1998	0.095582952	4955	0.741435358
53	1999	0.102052842	7005	0.712697173
54	2000	0.105232537	9034	0.547169537
55	2001	0.108329697	10693	0.627480361
56	2002	0.107044449	9011	0.585844457
57	2003	0.105846562	12911	0.35938413
58	2004	0.109676418	15041	0.408835536
59	2005	0.110235118	15895	0.475686392
60	2006	0.107756259	13850	0.450186347
61	2007	0.105636132	9626	0.615404342
62	2008	0.101395754	8104	

Appendix G. Variable Cross Reference Table

With the exception of the Pipeline Tariff Submodule (PTS) all of the equations in this model documentation report are the same as those used in the model FORTRAN code. Table G-1 presents cross references between model equation variables defined in this document and in the FORTRAN code for the PTS.

Table G-1. Cross Reference of PTM Variables Between Documentation and Code

Documentation	Code Variable	Equation #
$R_{i,f}$	Not represented	157
$R_{i,v}$	Not represented	158
ALL_f	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	157
ALL_v	AVA_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	158
R_i	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	157, 158
FC_a	Not represented	159
VC_a	Not represented	160
$R_{i,f,r}$	RFC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	161
$R_{i,f,u}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	162
$R_{i,v,r}$	RVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	163
$R_{i,v,u}$	UVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	164
$ALL_{f,r}$	AFR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	161
$ALL_{f,u}$	AFU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	162
$ALL_{v,r}$	AVR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	163
$ALL_{v,u}$	AVU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	164

Documentation	Code Variable	Equation #
ξ_i	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	222, 223, 225-228
$Item_{i,a,t}$	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	222, 223, 225-228
$FC_{a,t}$	Not represented	222
$VC_{a,t}$	Not represented	223
$TCOS_{a,t}$	Not represented	224, 229
$RFC_{a,t}$	RFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	225
$UFC_{a,t}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	225
$RVC_{a,t}$	RVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	227
$UVC_{a,t}$	UVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	228
λ_i	AFR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	225, 226
μ_i	AVR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	227, 228
a - arc, t - year, i - cost-of-service component index		

Appendix H. Coal-to-Gas Submodule

A Coal-to-Gas (CTG) algorithm has been incorporated into the NGTDM to project potential new CTG plants at the census division level and the associated pipeline quality gas production. The Coal-to-Gas process with no carbon sequestration is adopted as the generic facility for the CTG. The CTG_INVEST subroutine calculates the annualized capital costs, operating costs, and other variable costs for a generic coal-to-gas plant producing 100 MMcf/day (Appendix E, CTG_PUCAP) of pipeline quality synthetic gas from coal. The capital costs are converted into a per unit basis by dividing by the plant's assumed output of gas. Capital and operating costs are assumed to decline over the forecast due to technological improvements. To determine whether it is profitable to build a CTG plant, the per unit capital and operating costs plus the coal costs are compared to the average market price of natural gas and electricity. If a CTG plant is profitable, the actual number of plants to be built is set using the Mansfield-Blackman market penetration algorithm. Any new generic plant is assumed to be built in the regions with the greatest level of profitability and to produce pipeline quality natural gas and cogenerated electricity (cogen) for sale to the grid.

Electricity generated by a CTG facility is partially consumed in the facility, while the remainder is assumed to be sold to the grid at wholesale market prices (EWSPRCN, 87$/MWh, from the EMM). Cogeneration for each use is set for a generic facility using assumed ratios of electricity produced to coal consumed (Appendix E, own—CTG_BASECGS, grid—CTG_BASCGG). The revenue from cogen sales is treated as a credit (CGNCRED) by the model to offset the costs (feedstock, fixed, and operation costs) of producing CTG syngas. The annualized transmission cost (CGNTRNS) for cogen sent to the grid is accounted for in the operating cost of the CTG facility.

The primary inputs to the CTG model include a mine-mouth coal price (PCLGAS, 87$/MMBtu, from the Coal Market Module (CMM)) and a regional wholesale equivalent natural gas price (NODE_ENDPR, 87$/Mcf). A carbon tax (JCLIN, 87$/MMBtu from the Integration Module) is added to the coal price as well as a penalty for SO2 and HG. If the CTG plant is deemed to be economic, the final quantity of coal demanded (QCLGAS, Quad Btu/yr) is sent back to the CMM for feedback. The final outputs from the model are coal consumed, gas produced, electricity consumed, and electricity sold to the grid.

Investment decisions for building new CTG facilities are based on the total investment cost of a CTG plant (CTG_INVCST). Actual cash flows associated with the operation of the individual plants are considered, as well as cash flows associated with capital for the construction of new plants. Terms for capital-related financial charges (CAPREC) and fixed operating costs (FXOC) are included.

$$CTG\_INVCST = CAPREC + FXOC \tag{306}$$

Once a build decision is made, a Mansfield-Blackman algorithm for market penetration is used to determine the limit on the number of plants allowed to build in a given year. The investment costs are further adjusted to account for learning and for resource competition. The methodologies used to calculate the capital-related financial charges and the fixed operating costs, the Mansfield-Blackman model, and investment costs adjustments are presented in detail below.

Capital-Related Financial Charges for Coal-to-Gas

A discounted cash flow calculation is used to determine the annual capital charge for a CTG plant investment. The annual capital recovery charge assumes a discount rate equal to the cost of capital, which includes the cost of equity (CTGCOE) and interest payments on any loans or other debt instruments used as part of capital project financing (CTGCOD) with an assumed interest rate of the Industrial BAA bond rate (MC_RMCORPBAA, from MACRO) plus an additional risk premium (Appendix E, BA_PREM). Together, this translates into the capital recovery factor (CTG_RECRAT) which is calculated on an after-tax basis.

Some of the steps associated with the capital-related financial charge estimates are conducted exogenous to NEMS (Step 0 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant capital-related cost estimation algorithm are:

0) Estimation of the inside battery limit field cost (ISBL)
1) Year-dollar and location adjustments for ISBL Field Costs
2) Estimation of outside battery limit field cost (OSBL) and Total Field Cost
3) Estimation of Total Project Cost
4) Calculate Annual Capital Recovery
5) Convert capital related financial costs to a "per-unit" basis

Step 0 involves several adjustments which must be made prior to input into the NGTDM; steps 1-4 are performed within the NGTDM.

Step 0 - Estimation of ISBL Field Cost
The inside battery limits (CTG_ISBL) field costs include direct costs such as major equipment, bulk materials, direct labor costs for installation, construction subcontracts, and indirect costs such as distributables. The ISBL investment and labor costs were provided for plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in 2004 dollars.

Step 1 - Year-Dollar and Location Adjustments to ISBL Field Costs
Before utilizing the ISBL investment cost information, the raw data must be converted according to the following steps:

a) Adjust the ISBL field and labor costs from 2004 dollars, first to the year-dollar reported by NEMS, using the Nelson-Farrar refining industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 year dollars used internally by the NEMS.

b) Convert the ISBL field costs in 1987 dollars from a PADD III basis (Appendix E, XBM_ISBL) to costs in the NGTDM demand regions using location multipliers (Appendix E, CTG_INVLOC). The location multipliers represent differences in material costs between the various regions.

$$CTG\_ISBL = CTG\_INVLOC * BM\_ISBL / 1000 \tag{307}$$

Step 2 - Estimation of OSBL and Total Field Cost
The outside battery-limit (OSBL) costs for CTG are included in the inside battery-limit costs. The total field cost (CTG_TFCST) is the sum of ISBL and OSBL

$$CTG\_TFCST = (1 - CTG\_OSBLFAC) * CTG\_ISBL \tag{308}$$

The OSBL field cost is estimated as a fraction (Appendix E, CTG_OSBLFAC) of the ISBL costs.

Step 3 - Estimation of Total Project Cost
The total project investment (CTG_TPI) is the sum of the total field cost (Eq. 3) and other one-time costs (CTG_OTC).

$$CTG\_TPI = CTG\_TFCST + CTG\_OTC \tag{309}$$

Other one-time costs include the contractor's cost (such as home office costs), the contractor's fee and a contractor's contingency, the owner's cost (such as pre-startup and startup costs), and the owner's contingency and working capital. The other one-time costs are estimated as a function of total field costs using cost factors (OTCFAC):

$$CTG\_OTC = OTCFAC * CTG\_TFCST \tag{310}$$

where,

$$\begin{aligned} OTCFAC = {} & CTG\_PCTENV + CTG\_PCTCNTG + CTG\_PCTLND + \\ & CTG\_PCTSPECL + CTG\_PCTWC \end{aligned} \tag{311}$$

and,

CTG_PCTENV	=	Home, office, contractor fee
CTG_CNTG	=	Contractor & owner contingency
CTG_PCTLND	=	Land
CTG_PCTSPECL	=	Prepaid royalties, license, start-up costs
CTG_PCTWC	=	Working capital

The total project investment given above represents the total project cost for 'overnight construction.' The total project investment at project completion and startup will be discussed below.

Closely related to the total project investment are the fixed capital investment (CTG_FCI) and total depreciable investment (CTG_TDI). The fixed capital investment is equal to the total project investment less working capital. It is used to estimate capital-related fixed operating costs.

$$WRKCAP = CTG\_PCTWC * CTG\_TFCST \tag{312}$$

Thus,

$$CTG\_FCI = CTG\_TPI - WKRCAP \tag{313}$$

For the CTG plant, the total depreciable investment (CTG_TDI) is assumed to be equal to the total project investment.

Step 4 - Annual Capital Recovery

The annual capital recovery (ACAPRCV) is the difference between the total project investment (TPI) and the recoverable investment (RCI), all in terms of present value (e.g., at startup). The TPI estimated previously is for overnight construction (ONC). In reality, the TPI is spread out through the construction period. Land costs (LC) will occur as a lump-sum payment at the beginning of the project, construction expenses (TPI – WC – LC = FCI - LC) will be distributed during construction, and working capital (WC) expenses will occur as a lump-sum payment at startup. Thus, the TPI at startup (present value) is determined by discounting the construction expenses (assumed as discrete annual disbursements) and adding working capital (WC):

$$\begin{aligned} TPI\_START = {} & FVI\_CONSTR * LAND + FV\_CONSTR * \\ & (CTG\_FCI - LAND) + WRKCAP \end{aligned} \tag{314}$$

where,

FVI_CONSTR	=	Future-value compounding factor for an instantaneous payment made n years before the startup year
FV_CONSTR	=	Future-value compounding factor for discrete uniform payments made at the beginning of each year starting n years before the startup year.

The future-value factors are a function of the number of compounding periods (n), and the interest rate (r) assumed for compounding. In this case, (n) equals the construction time in years before startup, and the compounding rate used is the cost of capital (CTG_RECRAT).

The recoverable investment (RCI_START) includes the value of the land and the working capital (assumed not to depreciate over the life of the project), as well as the salvage value (PRJSDECOM) of the used equipment:

$$RCI\_START = PV\_PRJ * (LAND + WKRCAP + PRJSDECOM) \tag{315}$$

The present value of RCI is subtracted from the TPI at startup to determine the present value of the project investment (PVI):

$$PVI\_START = TPI\_START - RCI\_START \tag{316}$$

Thus, the annual capital recovery (ACAPRCV) is given by:

$$ACAPRCV = LC\_LIFE * PVI\_START \tag{317}$$

where,

LC_LIFE = uniform- value leveling factor for a periodic payment (annuity) made at the end of each year for (n) years in the future

The depreciation tax credit (DTC) is based on the depreciation schedule for the investment and the total depreciable investment (TDI). The simplest method used for depreciation calculations is the straight-line method, where the total depreciable investment is depreciated by a uniform annual amount over the tax life of the investment. Generic equations representing the present value and the levelized value of the annual depreciation charge are:

$$ADEPREC = CTG\_TDI / CTG\_PRJLIFE \tag{318}$$
$$ADEPTAXC = ADEPREC * FEDST\_TAX \tag{319}$$
$$ACAPCHRGAT = ACAPRCV - ADEPTAXC \tag{320}$$
$$DCAPCHRGAT = ACAPCHRGAT / 365 \tag{321}$$

where,

ADEPREC = annual levelized depreciation
ADEPTAXC = levelized depreciation tax credit, after federal and state taxes
ACAPCHRGAT = annual capital charge, after tax credit
DCAPCHRGAT = daily capital charge, after tax credit

Step 5 - Convert Capital Costs to a ‘per-day’, ‘per-capacity’ Basis
The annualized capital-related financial charge is converted to a daily charge, and then converted to a “per-capacity” basis by dividing the result by the operating capacity of the unit being evaluated. The result is a fixed operation cost on a per-mcf basis (CAPREC).

CTG Plant Fixed Operating Costs
Fixed operating costs (FXOC), a component of total product cost, are costs incurred at the plant that do not vary with plant throughput, and any other costs which cannot be controlled at the plant level. These include such items as wages, salaries and benefits; the cost of maintenance, supplies and repairs; laboratory charges; insurance, property taxes and rent; and other overhead costs. These components can be factored from either the operating labor requirement or the capital cost.

Like capital cost estimations, operating cost estimations, involve a number of distinct steps. Some of the steps associated with the FXOC estimate are conducted exogenous to NEMS (Step 0 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant fixed operating cost estimation algorithm are:

0) Estimation of the annual cost of direct operating labor
1) Year-dollar and location adjustment for operating labor costs (OLC)
2) Estimation of total labor-related operating costs (LRC)
3) Estimation of capital-related operating costs (CRC)
4) Convert fixed operating costs to a "per-unit" basis

Step 0 involves several adjustments which must be made prior to input into the NGTDM; steps 1-4 are performed within the NGTDM.

Step 0 – Estimation of Direct Labor Costs
Direct labor costs are reported based on a given processing unit size. Operation and labor costs were provided for plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in 2004 dollars.

Step 1 – Year-Dollar and Location Adjustment for Operating Labor Costs
Before the labor cost data can be utilized, it must be converted via the following steps:

a) Adjust the labor costs from 2004 dollars, first to the year-dollar reported by NEMS using the Nelson-Farrar refining-industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 dollars used internally by the NEMS (Appendix E, XBM_LABOR).

b) Convert the 1987 operating labor costs from a PADD III (Gulf Coast) basis into regional (other U.S. PADDs) costs using regional location factors. The location multiplier (Appendix E, LABORLOC) represents differences in labor costs between the various locations and includes adjustments for construction labor productivity.

$$CTG\_LABOR = LABORLOC * BM\_LABOR \tag{322}$$

Location multipliers are translated to the NGTDM demand regions.

Step 2 - Estimation of Labor-Related Fixed Operating Costs
Fixed operating costs related to the cost of labor include the salaries and wages of supervisory and other staffing at the plant, charges for laboratory services, and payroll benefits and other plant overhead. These labor-related fixed operating costs (FXOC_LABOR) can be factored from the direct operating labor cost. This relationship is expressed by:

$$FXOC\_STAFF = CTG\_LABOR * CTG\_STAFF\_LCFAC \tag{323}$$

$$FXOC\_OH = (CTG\_LABOR + FXOC\_STAFF) * CTG\_OH\_LCFAC \tag{324}$$

$$FXOC\_LABOR = CTG\_LABOR + FXOC\_STAFF + FXOC\_OH \tag{325}$$

where,

FXOC_STAFF = Supervisory and staff salary costs
FXOC_OH = Benefits and overhead

Step 3 - Estimation of Capital-Related Fixed Operating Costs
Capital–related fixed operating costs (FXOC_CAP) include insurance, local taxes, maintenance, supplies, non-labor related plant overhead, and environmental operating costs. These costs can be factored from the fixed capital investment (CTG_FCI). This relationship is expressed by:

$$FXOC\_INS = CTG\_FCI * INS\_FAC \tag{326}$$

$$FXOC\_TAX = CTG\_FCI * TAX\_FAC \tag{327}$$

$$FXOC\_MAINT = CTG\_FCI * MAINT\_FAC \tag{328}$$

$$FXOC\_OTH = CTG\_FCI * OTH\_FAC \tag{329}$$

$$\begin{aligned} FXOC\_CAP = {} & FXOC\_INS + FXOC\_TAX + \\ & FXOC\_MAINT + FXOC\_OTH \end{aligned} \tag{330}$$

where,

INS_FAC = Yearly Insurance
TAX_FAC = Local Tax Rate
MAINT_FAC = Yearly Maintenance
OTH_FAC = Yearly Supplies, Overhead, Etc.

Step 4 - Convert Fixed Operating Costs to a "per-capacity" Basis
On a "per-capacity" basis, the FXOC is the sum of capital-related operating costs and labor-related operating costs, divided by the operating capacity of the unit being evaluated.

Mansfield-Blackman Model for Market Penetration
The Mansfield-Blackman model for market penetration has been incorporated to limit excessive growth of CTG (on a national level) once they become economically feasible.[99] The indices associated with this modeling algorithm are user inputs that define the characteristics of the CTG process. They include an innovation index of the industry (Appendix E, CTG_IINDX), the relative profitability of the investment within the industry (Appendix E, CTG_PINDX), the relative size of the investment (per plant) as a percentage of total company value (Appendix E, CTG_SINVST), and a maximum penetration level (total number of units, Appendix E, CTG_BLDX).[100]

[99] E. Mansfield, "Technical Change and the Rate of Imitation," *Econometrica*, Vol. 29, No. 4 (1961), pp. 741-765. A.W. Blackman, "The Market Dynamics of Technological Substitution," *Technological Forecasting and Social Change*, Vol. 6 (1974), pp. 41-63.

[100] These have been defined in a memorandum from Andy Kydes (EIA) to Han-Lin Lee (EIA), entitled "Development of a model for optimistic growth rates for the coal-to-liquids (CTG) technology in NEMS," dated March 23, 2002.

$$KFAC = -LOG((CTG\_BLDX / NCTGBLT) - 1) \quad (331)$$

$$PHI = -0.3165 + (0.23221 * CTG\_IINDX) + (0.533 * CTG\_PINDX) - (0.027 * CTG\_SINVST) \quad (332)$$

$$SHRBLD = 1/(1 + EXP(-KFAC - (YR * PHI))) \quad (333)$$

$$CTGBND = CTG\_BLDX * SHRBLD \quad (334)$$

where,

CTG_BLDX = maximum number of plants allowed
NCTGBLT = number of plants already built
SHRBLD = the share of the maximum number of plants that can be built in a given year
CTGBND = the upper bound on the number of plants to build

Investment Cost Adjustments
To represent cost improvements over time (due to learning), a decline rate (CTG_DCLCAPCST) is applied to the original CTG capital costs after builds begin.

$$CTG\_INVADJ = CTG\_INVBAS * (1 - CTG\_DCLCAPCST)^{(YR - CTG\_BASYR)} \quad (335)$$

where,

CTG_INVBAS = the initial CTG investment cost
CTG_BASYR = the first year CTG plants are allowed to build
CTG_INVADJ = the adjusted CTG investment cost

However, once the capacity builds exceed 1.1 bcf/day, a supplemental algorithm is applied to increase costs in response to impending resource depletions (such as competition for water).[101]

$$CTG\_CSTADD = 15 * TANH(0.4 * (MAX(0, (CTGPRODC / 1127308) - 1))) \quad (336)$$

where,

CTGPRODC = current CTG production
CTG_CSTADD = the additional cost

[101] The basic algorithm is defined in a memorandum from Andy Kydes (EIA) to William Brown (EIA), entitled "CTL run-- add to total CTLCST in ADJCTLCST sub," dated September 29, 2006.

DOE/EIA-M063(2011)

Documentation of the Oil and Gas Supply Module (OGSM)

July 2011

Office of Energy Analysis
U.S. Energy Information Administration
U.S. Department of Energy
Washington, DC 20585

Update Information

This edition of the *Documentation of the Oil and Gas Supply Module* reflects changes made to the oil and gas supply module over the past year for the *Annual Energy Outlook 2011*. The major changes include:

- Texas Railroad Commission District 5 is included in the Southwest region instead of the Gulf Coast region.
- Re-estimation of Lower 48 onshore exploration and development costs.
- Updates to crude oil and natural gas resource estimates for emerging shale plays.
- Addition of play-level resource assumptions for tight gas, shale gas, and coalbed methane (Appendix 2.C).
- Updates to the assumptions used for the announced/nonproducing offshore discoveries.
- Revision of the North Slope New Field Wildcat (NFW) exploration wells drilling rate function. The NFW drilling rate is a function of the low-sulfur light projected crude oil prices and was statically estimated based on Alaska Oil and Gas Conservation Commission well counts and success rates.
- Recalibration of the Alaska oil and gas well drilling and completion costs based on the 2007 American Petroleum Institute Joint Association Survey drilling cost data.
- Updates to oil shale plant configuration, cost of capital calculation, and market penetration algorithms.
- Addition of natural gas processing and coal-to-liquids plants as anthropogenic sources of carbon dioxide (CO_2).

Contents

Appendices

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Figures

1. Introduction

The purpose of this report is to define the objectives of the Oil and Gas Supply Module (OGSM), to describe the model's basic approach, and to provide detail on how the model works. This report is intended as a reference document for model analysts, users, and the public. It is prepared in accordance with the U.S. Energy Information Administration's (EIA) legal obligation to provide adequate documentation in support of its statistical and forecast reports (Public Law 93-275, Section 57(b)(2)).

Projected production estimates of U.S. crude oil and natural gas are based on supply functions generated endogenously within the National Energy Modeling System (NEMS) by the OGSM. The OGSM encompasses both conventional and unconventional domestic crude oil and natural gas supply. Crude oil and natural gas projections are further disaggregated by geographic region. The OGSM projects U.S. domestic oil and gas supply for six Lower 48 onshore regions, three offshore regions, and Alaska. The general methodology relies on forecasted profitability to determine exploratory and developmental drilling levels for each region and fuel type. These projected drilling levels translate into reserve additions, as well as a modification of the production capacity for each region.

The OGSM utilizes both exogenous input data and data from other modules within the NEMS. The primary exogenous inputs are resource levels, finding-rate parameters, costs, production profiles, and tax rates - all of which are critical determinants of the expected returns from projected drilling activities. Regional projections of natural gas wellhead prices and production are provided by the Natural Gas Transmission and Distribution Module (NGTDM). Projections of the crude oil wellhead prices at the OGSM regional level come from the Petroleum Market Model (PMM). Important economic factors, namely interest rates and GDP deflators, flow to the OGSM from the Macroeconomic Module. Controlling information (e.g., forecast year) and expectations information (e.g., expected price paths) come from the Integrating Module (i.e. system module).

Outputs from the OGSM go to other oil and gas modules (NGTDM and PMM) and to other modules of the NEMS. To equilibrate supply and demand in the given year, the NGTDM employs short-term supply functions (with the parameters provided by the OGSM) to determine non-associated gas production and natural gas imports. Crude oil production is determined within the OGSM using short-term supply functions. These short-term supply functions reflect potential oil or gas flows to the market for a 1-year period. The gas functions are used by the NGTDM and the oil volumes are used by the PMM for the determination of equilibrium prices and quantities of crude oil and natural gas at the wellhead. The OGSM also provides projections of natural gas production to the PMM to estimate the corresponding level of natural gas liquids production. Other NEMS modules receive projections of selected OGSM variables for various uses. Oil and gas production is passed to the Integrating Module for reporting purposes. Forecasts of oil and gas production are also provided to the Macroeconomic Module to assist in forecasting aggregate measures of output.

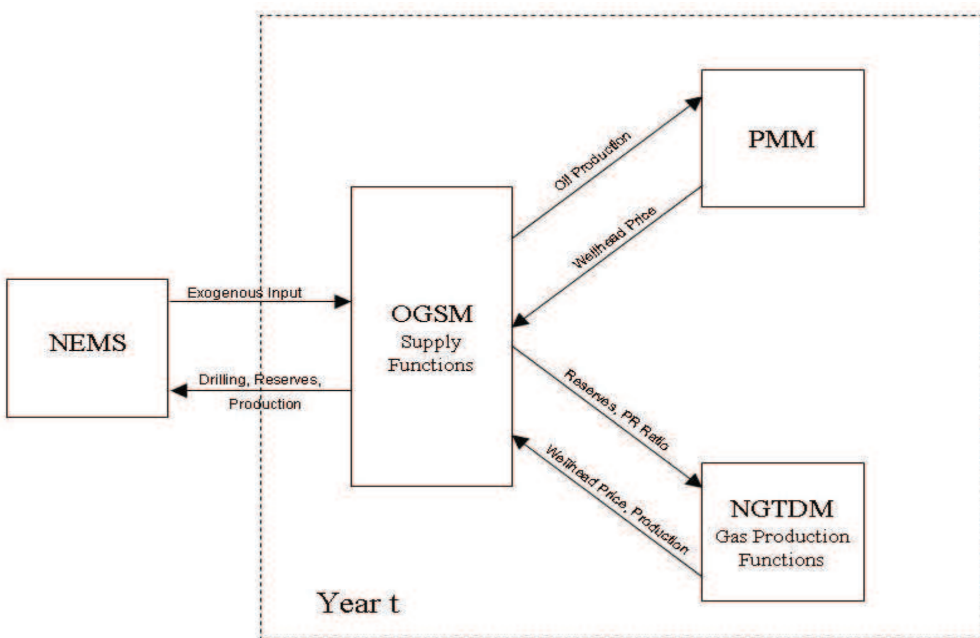
The OGSM is archived as part of the NEMS. The archival package of the NEMS is located under the model acronym NEMS2011. The NEMS version documented is that used to produce the *Annual Energy Outlook 2011 (AEO2011)*. The package is available on the EIA website.[1]

Model Purpose

The OGSM is a comprehensive framework used to analyze oil and gas supply potential and related issues. Its primary function is to produce domestic projections of crude oil and natural gas production as well as natural gas imports and exports in response to price data received endogenously (within the NEMS) from the NGTDM and PMM. Projected natural gas and crude oil wellhead prices are determined within the NGTDM and PMM, respectively. As the supply component only, the OGSM cannot project prices, which are the outcome of the equilibration of both demand and supply.

The basic interaction between the OGSM and the other oil and gas modules is represented in Figure 1-1. The OGSM provides beginning-of-year reserves and the production-to-reserves ratio to the NGTDM for use in its short-term domestic non-associated gas production functions and associated-dissolved natural gas production. The interaction of supply and demand in the NGTDM determines non-associated gas production.

Figure 1-1. OGSM Interface with Other Oil and Gas Modules



[1] ftp://ftp.eia.doe.gov/pub/forecasts/aeo/

The OGSM provides domestic crude oil production to the PMM. The interaction of supply and demand in the PMM determines the level of imports. System control information (e.g., forecast year) and expectations (e.g., expect price paths) come from the Integrating Module. Major exogenous inputs include resource levels, finding-rate parameters, costs, production profiles, and tax rates -- all of which are critical determinants of the oil and gas supply outlook of the OGSM.

The OGSM operates on a regionally disaggregated level, further differentiated by fuel type. The basic geographic regions are Lower 48 onshore, Lower 48 offshore, and Alaska, each of which, in turn, is divided into a number of subregions (see Figure 1-2). The primary fuel types are crude oil and natural gas, which are further disaggregated based on type of deposition, method of extraction, or geologic formation. Crude oil supply includes lease condensate. Natural gas is differentiated by non-associated and associated-dissolved gas.[2] Non-associated natural gas is categorized by fuel type: low-permeability carbonate and sandstone (conventional), high-permeability carbonate and sandstone (tight gas), shale gas, and coalbed methane.

The OGSM provides mid-term (through year 2035) projections and serves as an analytical tool for the assessment of alternative supply policies. One publication that utilizes OGSM forecasts is the *Annual Energy Outlook (AEO)*. Analytical issues that OGSM can address involve policies that affect the profitability of drilling through impacts on certain variables, including:

- drilling and production costs;
- regulatory or legislatively mandated environmental costs;
- key taxation provisions such as severance taxes, State or Federal income taxes, depreciation schedules and tax credits; and
- the rate of penetration for different technologies into the industry by fuel type.

The cash flow approach to the determination of drilling levels enables the OGSM to address some financial issues. In particular, the treatment of financial resources within the OGSM allows for explicit consideration of the financial aspects of upstream capital investment in the petroleum industry.

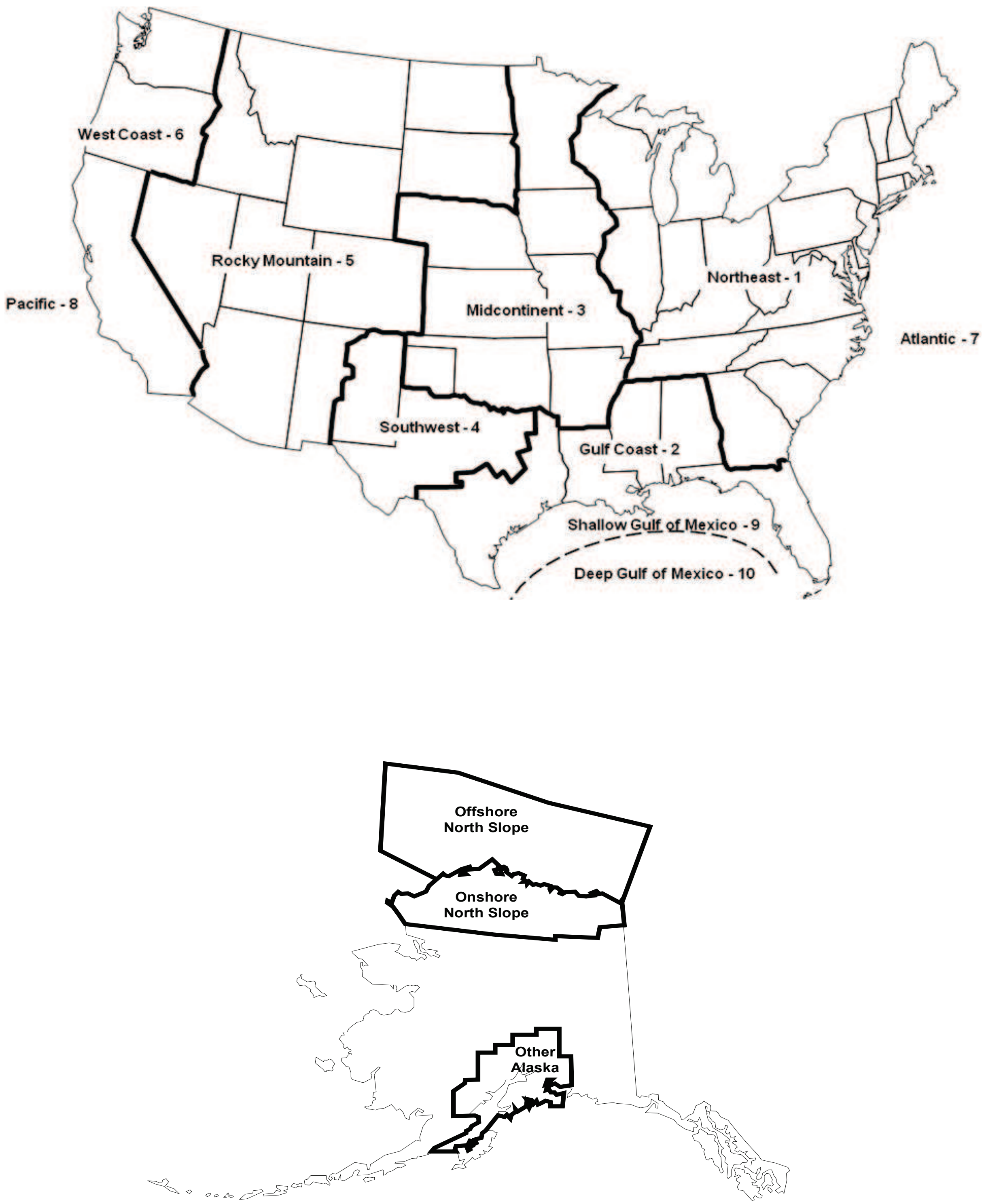
The OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for technically recoverable oil and gas resources for each of the sources of domestic production (i.e., geographic region/fuel type combinations). With some modification, this feature could allow the model to be used for the analysis of issues involving:

- the uncertainty surrounding the technically recoverable oil and gas resource estimates, and
- access restrictions on much of the offshore Lower 48 states, the wilderness areas of the onshore Lower 48 states, and the 1002 Study Area of the Arctic National Wildlife Refuge (ANWR).

[2]Nonassociated (NA) natural gas is gas not in contact with significant quantities of crude oil in a reservoir. Associated-dissolved natural gas consists of the combined volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

In general, the OGSM is used to foster a better understanding of the integral role that the oil and gas extraction industry plays with respect to the entire oil and gas industry, the energy subsector of the U.S. economy, and the total U.S. economy.

Figure 1-2. Oil and Gas Supply Regions

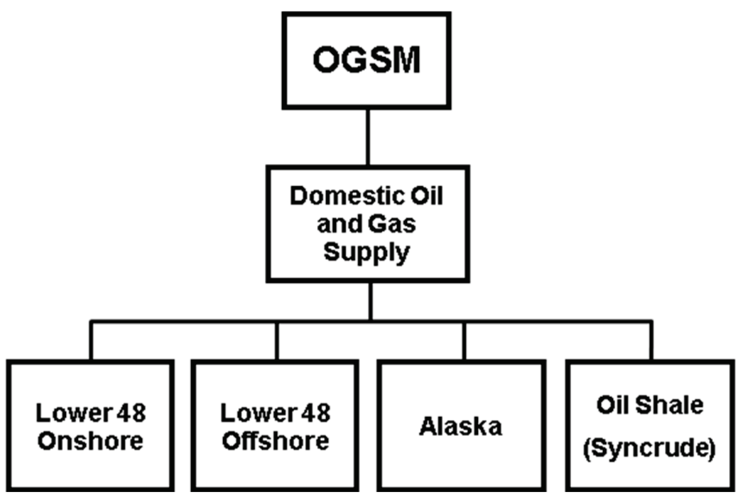


Model Structure

The OGSM consists of a set of submodules (Figure 1-3) and is used to perform supply analysis of domestic oil and gas as part of the NEMS. The OGSM provides crude oil production and parameter estimates representing natural gas supplies by selected fuel types on a regional basis to support the market equilibrium determination conducted within other modules of the NEMS. The oil and gas supplies in each period are balanced against the regionally-derived demand for the produced fuels to solve simultaneously for the market clearing prices and quantities in the wellhead and end-use markets. The description of the market analysis models may be found in the separate methodology documentation reports for the Petroleum Market Module (PMM) and the Natural Gas Transmission and Distribution Model (NGTDM).

The OGSM represents the activities of firms that produce oil and natural gas from domestic fields throughout the United States. The OGSM encompasses domestic crude oil and natural gas supply by both conventional and unconventional recovery techniques. Natural gas is categorized by fuel type: high-permeability carbonate and sandstone (conventional), low-permeability carbonate and sandstone (tight gas), shale gas, and coalbed methane. Unconventional oil includes production of synthetic crude from oil shale (syncrude). Crude oil and natural gas projections are further disaggregated by geographic region. Liquefied natural gas (LNG) imports and pipeline natural gas import/export trade with Canada and Mexico are determined in the NGTDM.

Figure 1-3. Submodules within the Oil and Gas Supply Module



The model's methodology is shaped by the basic principle that the level of investment in a specific activity is determined largely by its expected profitability. Output prices influence oil and gas supplies in distinctly different ways in the OGSM. Quantities supplied as the result of the annual market equilibration in the PMM and the NGTDM are determined as a direct result of the observed market price in that period. Longer-term supply responses are related to investments required for subsequent production of oil and gas. Output prices affect the expected profitability of these investment opportunities as determined by use of a discounted cash flow evaluation of representative prospects. The OGSM incorporates a complete and representative description of the processes by which oil and gas in the technically recoverable resource base[3] convert to proved reserves.[4]

The breadth of supply processes that are encompassed within OGSM result in different methodological approaches for determining crude oil and natural gas production from Lower 48 onshore, Lower 48 offshore, Alaska, and oil shale. The present OGSM consequently comprises four submodules. The Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) models crude oil and natural gas supply from resources in the Lower 48 States. The Offshore Oil and Gas Supply Submodule (OOGSS) models oil and gas exploration and development in the offshore Gulf of Mexico, Pacific, and Atlantic regions. The Alaska Oil and Gas Supply Submodule (AOGSS) models industry supply activity in Alaska. Oil shale (synthetic) is modeled in the Oil Shale Supply Submodule (OSSS). The distinctions of each submodule are explained in individual chapters covering methodology. Following the methodology chapters, four appendices are included: Appendix A provides a description of the discounted cash flow (DCF) calculation; Appendix B is the bibliography; Appendix C contains a model abstract; and Appendix D is an inventory of key output variables.

[3] *Technically recoverable resources* are those volumes considered to be producible with current recovery technology and efficiency but without reference to economic viability. Technically recoverable volumes include proved reserves and inferred reserves as well as undiscovered and other unproved resources. These resources may be recoverable by techniques considered either conventional or unconventional.

[4] *Proved reserves* are the estimated quantities that analyses of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

2. Onshore Lower 48 Oil and Gas Supply Submodule

Introduction

U.S. onshore lower 48 crude oil and natural gas supply projections are determined by the Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS). The general methodology relies on a detailed economic analysis of potential projects in known crude oil and natural gas fields, enhanced oil recovery projects, developing natural gas plays, and undiscovered crude oil and natural gas resources. The projects that are economically viable are developed subject to the availability of resource development constraints which simulate the existing and expected infrastructure of the oil and gas industries. The economic production from the developed projects is aggregated to the regional and the national levels.

OLOGSS utilizes both exogenous input data and data from other modules within the National Energy Modeling System (NEMS). The primary exogenous data includes technical production for each project considered, cost and development constraint data, tax information, and project development data. Regional projections of natural wellhead prices and production are provided by the Natural Gas Transmission and Distribution Model (NGTDM). From the Petroleum Market Module (PMM) come projections of the crude oil wellhead prices at the OGSM regional level.

Model Purpose

OLOGSS is a comprehensive model with which to analyze the crude oil and natural gas supply potential and related economic issues. Its primary purpose is to project production of crude oil and natural gas from the onshore lower 48 in response to price data received from the PMM and the NGTDM. As a supply submodule, OLOGSS does not project prices.

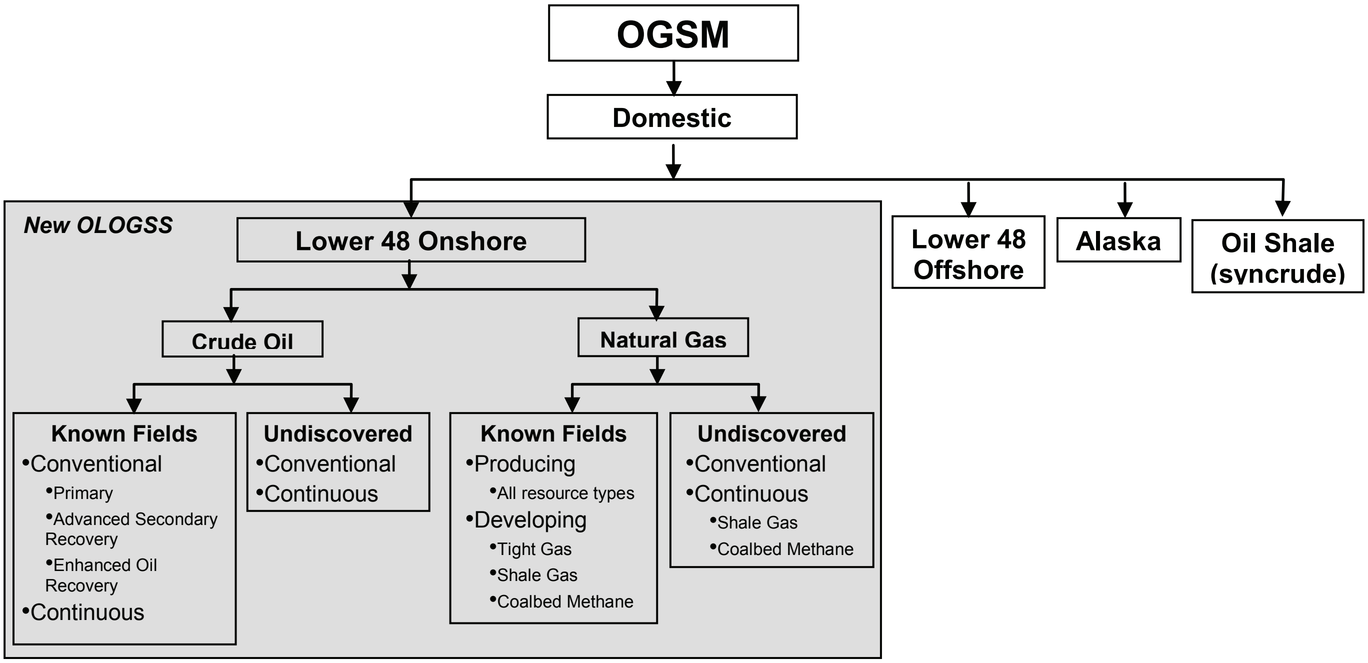
The basic interaction between OLOGSS and the OGSM is illustrated in figure 2-1. As seen in the figure, OLOGSS models the entirety of the domestic crude oil and natural gas production within the onshore lower 48.

Resources Modeled

Crude Oil Resources

Crude oil resources, as illustrated in figure 2-1, are divided into known fields and undiscovered fields. For known resources, exogenous production type curves are used for quantifying the technical production profiles from known fields under primary, secondary, and tertiary recovery processes. Primary resources are also quantified for their advanced secondary recovery (ASR) processes that include the following: waterflooding, infill drilling, horizontal continuity, and horizontal profile modification. Known resources are evaluated for the potential they may possess when employing enhanced oil recovery (EOR) processes such as CO_2 flooding, steam flooding, polymer flooding and profile modification. Known crude oil resources include highly fractured continuous zones such as the Austin chalk formations and the Bakken shale formations.

Figure 2-1: Subcomponents within OGSM



Undiscovered crude oil resources are characterized in a method similar to that used for discovered resources and are evaluated for their potential production from primary and secondary techniques. The potential from an undiscovered resource is defined based on United States Geological Survey (USGS) estimates and is distinguished as either conventional or continuous. Conventional crude oil and natural gas resources are defined as discrete fields with well-defined hydrocarbon-water contacts, where the hydrocarbons are buoyant on a column of water. Conventional resources commonly have relatively high permeability and obvious seals and traps. In contrast, continuous resources commonly are regional in extent, have diffuse boundaries, and are not buoyant on a column of water. Continuous resources have very low permeability, do not have obvious seals and traps, are in close proximity to source rocks, and are abnormally pressured. Included in the category of continuous accumulations are hydrocarbons that occur in tight reservoirs, shale reservoirs, fractured reservoirs, and coal beds.

Natural Gas Resources

Natural gas resources, as illustrated in figure 2-1, are divided into known producing fields, developing natural gas plays, and undiscovered fields. Exogenous production type curves have been used to estimate the technical production from known fields. The undiscovered resources have been characterized based on resource estimates developed by the USGS. Existing databases of developing plays, such as the Marcellus Shale, have been incorporated into the model's resource base. The natural gas resource estimates have been developed from detailed geological characterizations of producing plays.

Processes Modeled

OLOGSS models primary, secondary and tertiary oil recovery processes. For natural gas, OLOGSS models discovered and undiscovered fields, as well as discovered and developing fields. Table 2-1 lists the processes modeled by OLOGSS.

Table 2-1: Processes Modeled by OLOGSS

Crude Oil Processes	Natural Gas Processes
Existing Fields and Reservoirs	Existing Radial Flow
Waterflooding in Undiscovered Resources	Existing Water Drive
CO_2 Flooding	Existing Tight Sands
Steam Flooding	Existing Dry Coal/Shale
Polymer Flooding	Existing Wet Coal/Shale
Infill Drilling	Undiscovered Conventional
Profile Modification	Undiscovered Tight Gas
Horizontal Continuity	Undiscovered Coalbed Methane
Horizontal Profile	Undiscovered Shale Gas
Undiscovered Conventional	Developing Shale Gas
Undiscovered Continuous	Developing Coalbed Methane
	Developing Tight Gas

Major Enhancements

OLOGSS is a play-level model that projects the crude oil and natural gas supply from the onshore lower 48. The modeling procedure includes a comprehensive assessment method for determining the relative economics of various prospects based on future financial considerations, the nature of the undiscovered and discovered resources, prevailing risk factors, and the available technologies. The model evaluates the economics of future exploration and development from the perspective of an operator making an investment decision. Technological advances, including improved drilling and completion practices, as well as advanced production and processing operations are explicitly modeled to determine the direct impacts on supply, reserves, and various economic parameters. The model is able to evaluate the impact of research and development (R&D) on supply and reserves. Furthermore, the model design provides the flexibility to evaluate alternative or new taxes, environmental, or other policy changes in a consistent and comprehensive manner.

OLOGSS provides a variety of levers that allow the user to model developments affecting the profitability of development:

- Development of new technologies
- Rate of market penetration of new technologies
- Costs to implement new technologies
- Impact of new technologies on capital and operating costs
- Regulatory or legislative environmental mandates

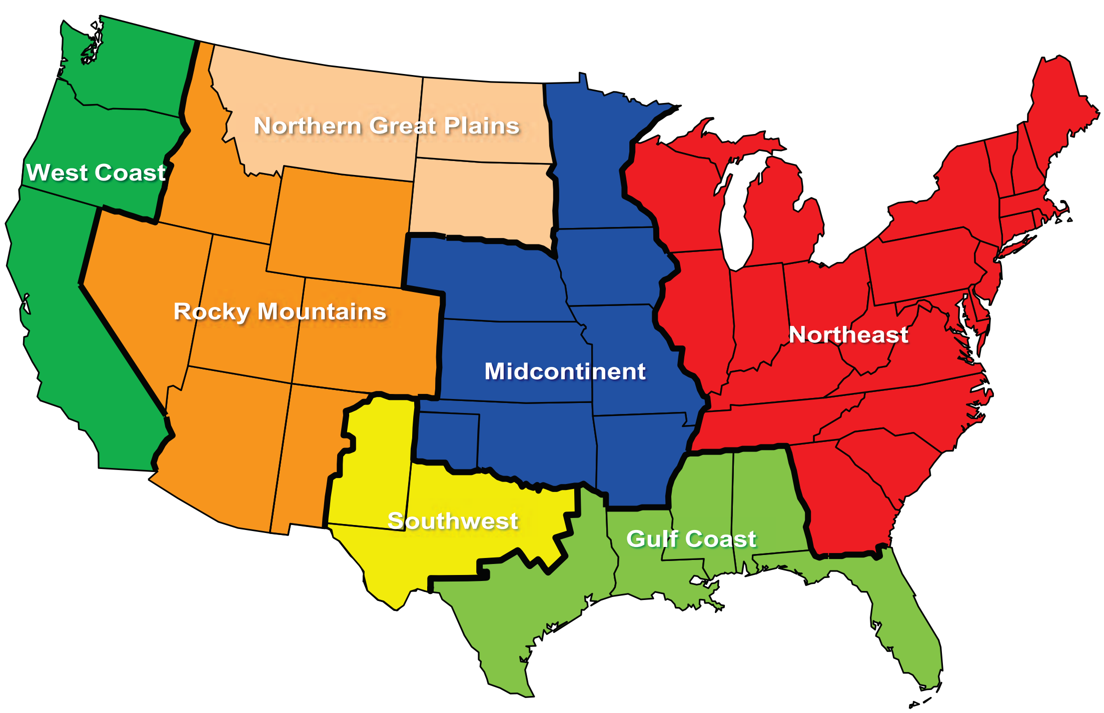
In addition, OLOGSS can quantify the effects of hypothetical developments that affect the resource base. OLOGSS is based on explicit estimates for technically recoverable crude oil and natural gas resources for each source of domestic production (i.e., geographic region/fuel type combinations).

OLOGSS is capable of addressing access issues concerning crude oil and natural gas resources located on federal lands. Undiscovered resources are divided into four categories:

- Officially inaccessible
- Inaccessible due to development constraints
- Accessible with federal lease stipulations
- Accessible under standard lease terms

OLOGSS uses the same geographical regions as the OGSM with one distinction. In order to capture the regional differences in costs and drilling activities in the Rocky Mountain region, the region has been divided into two sub-regions. These regions, along with the original six, are illustrated in figure 2-2. The Rocky Mountain region has been split to add the Northern Great Plains region. The results for these regions are aggregated before being passed to other OGSM or NEMS routines.

Figure 2-2: Seven OLOGSS Regions for Onshore Lower 48



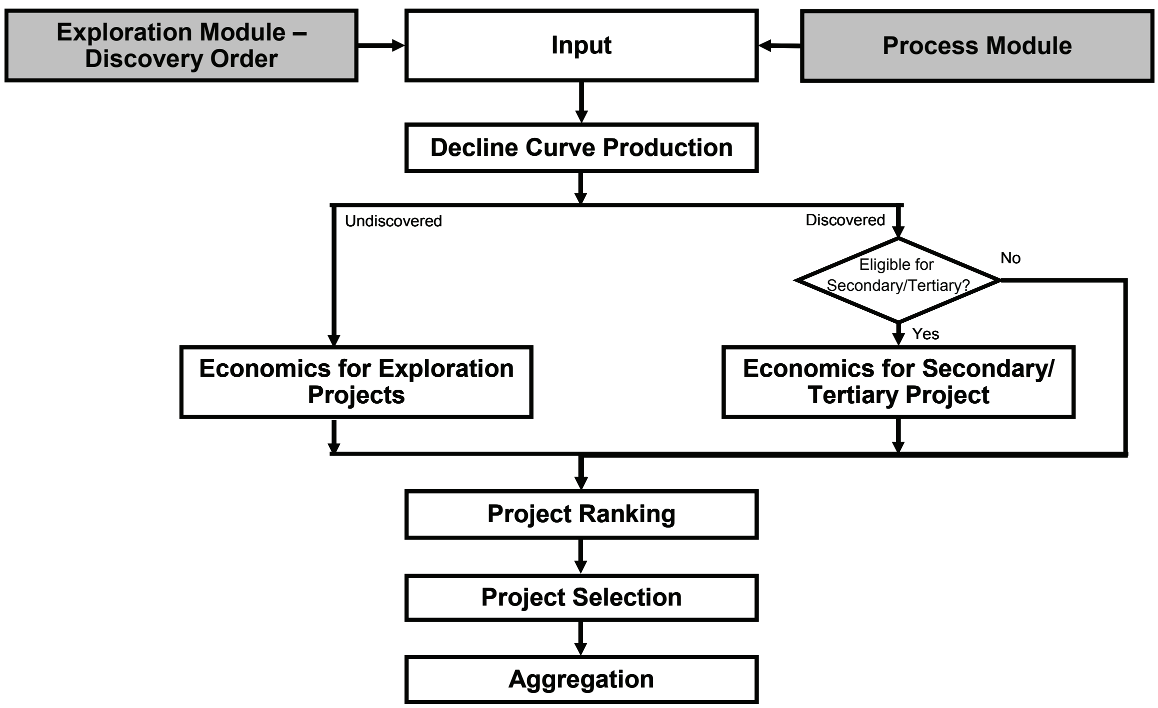
Model Structure

The OLOGSS projects the annual crude oil and natural gas production from existing fields, reserves growth, and exploration. It performs economic evaluation of the projects and ranks the reserves growth and exploration projects for development in a way designed to mimic the way decisions are made by the oil and gas industry. Development decisions and project selection depend upon economic viability and the competition for capital, drilling, and other available development constraints. Finally, the model aggregates production and drilling statistics using geographical and resource categories.

Overall System Logic

Figure 2-3 provides the overall system logic for the OLOGSS timing and economic module. This is the only component of OLOGSS which is integrated into NEMS.

Figure 2-3: OLOGSS Timing Module Overall System Logic



As seen in the figure, there are two primary sources of resource data. The exploration module provides the well-level technical production from the undiscovered projects which may be discovered in the next thirty years. It also determines the discovery order in which the projects will be evaluated by OLOGSS. The process module calculates the well-level technical production from known crude oil and natural gas fields, EOR and advanced secondary recovery (ASR) projects, and developing natural gas plays.

OLOGSS determines the potential domestic production in three phases. As seen in Figure 2-3, the first phase is the evaluation of the known crude oil and natural gas fields using a decline curve analysis. As part of the analysis, each project is subject to a detailed economic analysis used to determine the economic viability and expected life span of the project. In addition, the model applies regional factors used for history matching and resource base coverage. The remaining resources are categorized as either exploration or EOR/ASR. Each year, the exploration projects are subject to economic analysis which determines their economic viability and profitability.

For the EOR/ASR projects, development eligibility is determined before the economic analysis is conducted. The eligibility is based upon the economic life span of the corresponding decline curve project and the process-specific eligibility window. If a project is not currently eligible, it will be re-evaluated in future years. The projects which are eligible are subject to the same type of economic analysis applied to existing and exploration projects in order to determine the viability and relative profitability of the project.

After the economics have been determined for each eligible project, the projects are sorted. The exploration projects maintain their discovery order. The EOR/ASR projects are sorted by their relative profitability. The finalized lists are then considered by the project selection routines.

A project will be selected for development only if it is economically viable and if there are sufficient development resources available to meet the project's requirements. Development resource constraints are used to simulate limits on the availability of infrastructure related to the oil and gas industries. If sufficient resources are not available for an economic project, the project will be reconsidered in future years if it remains economically viable. Other development options are considered in this step, including the waterflooding of undiscovered conventional resources and the extension of CO_2 floods through an increase in total pore volume injected.

The production, reserves, and other key parameters for the timed and developed projects are aggregated at the regional and national levels.

The remainder of this document provides additional details on the logic and particular calculations for each of these steps. These include the decline analysis, economic analysis, timing decisions, project selection, constraints, and modeling of technology.

Known Fields

In this step, the production from existing crude oil and natural gas projects is estimated. A detailed economic analysis is conducted in order to calculate the economically viable production as well as the expected life of each project. The project life is used to determine when a project becomes eligible for EOR and ASR processes.

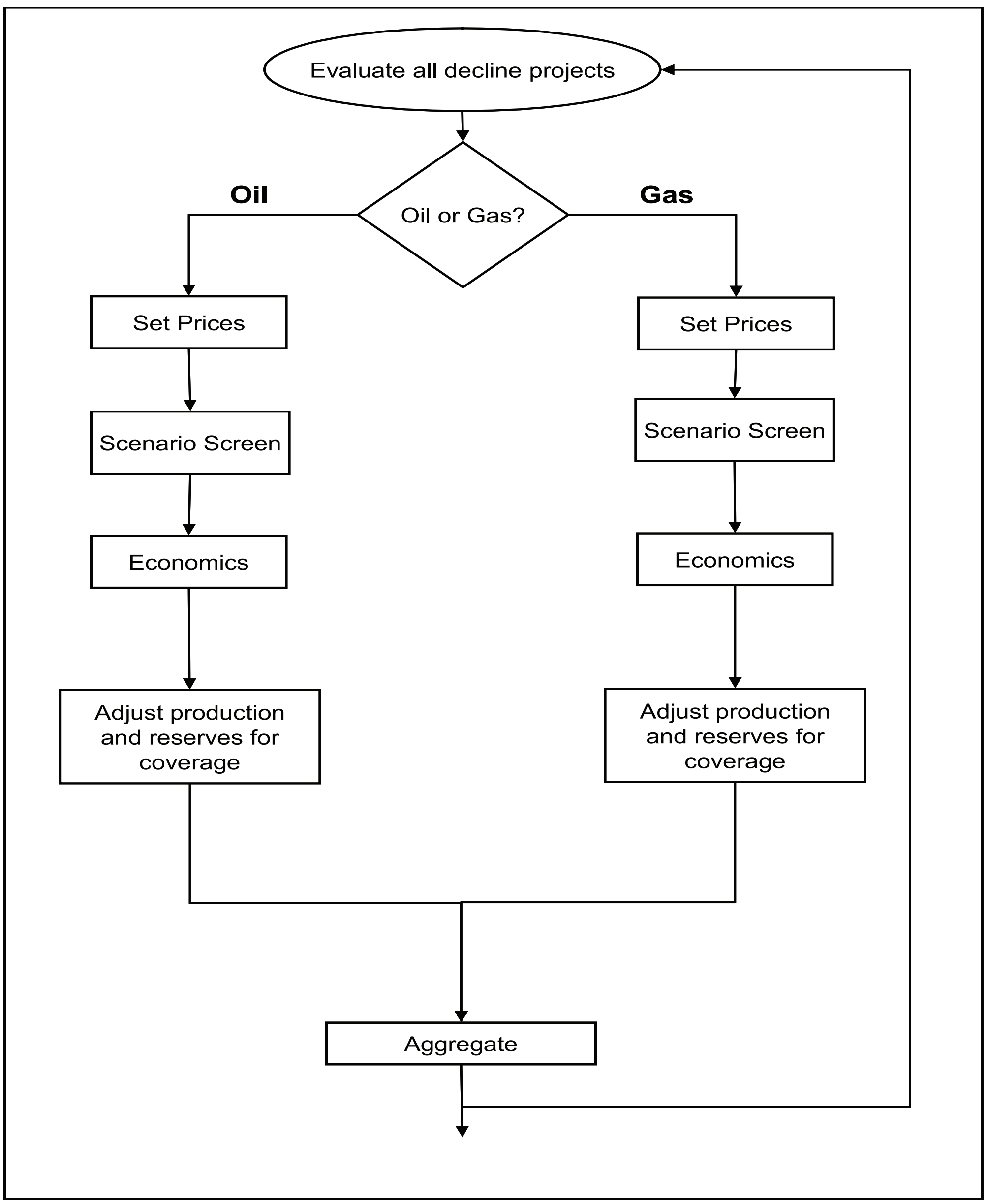
The logic for this process is provided in figure 2-4. For each crude oil project, regional prices are set and the project is screened to determine whether the user has specified any technology and/or economic levers. The screening considers factors including region, process, depth, and several other petro-physical properties. After applicable levers are determined, the project undergoes a detailed economic analysis.

After the analysis, resource coverage factors are applied to the economic production and reserves, and the project results are aggregated at the regional and national levels. In a final step, key parameters including the economic lifespan of the project are stored. A similar process is applied to the existing natural gas fields and reservoirs.

Resource coverage factors are applied in the model to ensure that historical production from existing fields matches that reported by EIA. These factors are calculated at the regional level and applied to production data for the following resources:

- Crude oil (includes lease condensates)
- High-permeability natural gas
- Coalbed methane
- Shale gas
- Tight gas

Figure 2-4: Decline Process Flowchart



Economics

Project Costs

OLOGSS conducts the economic analysis of each project using regional crude oil and natural gas prices. After these prices are set, the model evaluates the base and advanced technology cases for the project. The base case is defined as the current technology and cost scenario for the project; while the advanced case includes technology and/or cost improvements associated with the application of model levers. It is important to note that these cases – for which the assumption are applied to data for the project – are not the same as the *AEO* low, reference, or high technology cases.

For each technology case, the necessary petro-physical properties and other project data are set, the regional dryhole rates are determined, and the process specific depreciation schedule is assigned. The capital and operating costs for the project are then calculated and aggregated for both the base and advanced technology cases.

In the next step, a standard cashflow analysis is conducted, the discounted rate of return is calculated, and the ranking criteria are set for the project. Afterwards, the number and type of wells required for the project, and the last year of actual economic production are set. Finally, the economic variables, including production, development requirements, and other parameters, are stored for project timing and aggregation. All of these steps are illustrated in figure 2-5.

The details of the calculations used in conducting the economic analysis of a project are provided in the following description.

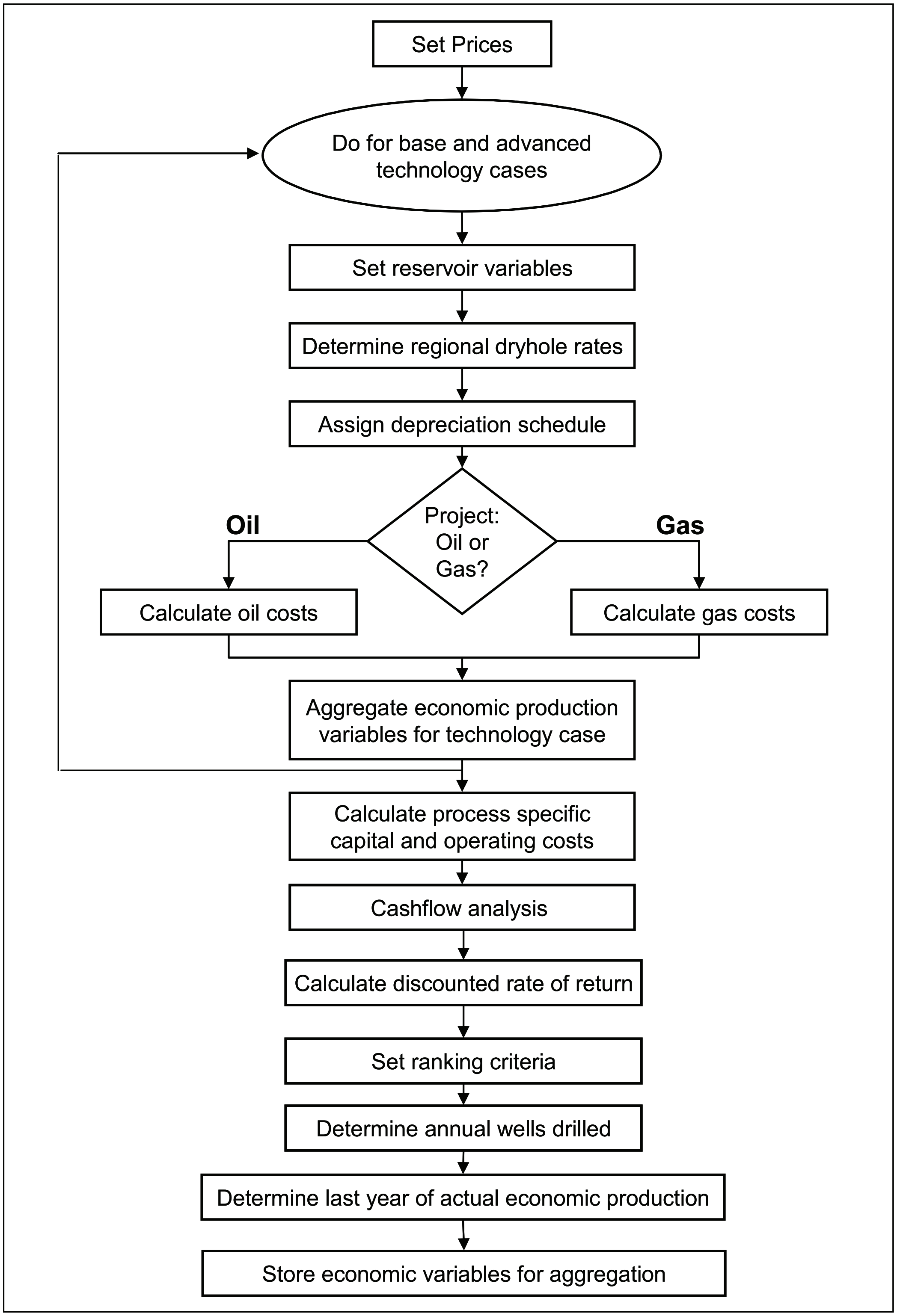
Determine the project shift: The first step is to determine the number of years the project development is shifted, i.e., the numbers of years between the discovery of a project and the start of its development. This will be used to determine the crude oil and natural gas price shift. The number of years is dependent upon both the development schedule – when the project drilling begins – and upon the process.

Determine annual prices: Determine the annual prices used in evaluating the project. Crude oil and natural gas prices in each year use the average price for the previous 5 years.

Begin analysis of base and advanced technology: To capture the impacts of technological improvements on both production and economics, the model divides the project into two categories. The first category – base technology – does not include improvements associated with technology or economic levers. The second category – advanced technology – incorporates the impact of the levers. The division of the project depends on the market penetration algorithm of any applicable technologies.

Determine the dryhole rate for the project: Assigns the regional dryhole rates for undiscovered exploration, undiscovered development, and discovered development. Three types of dryhole rates are used in the model: development in known fields and reservoirs, the first (wildcat) well in an exploration project, and subsequent wells in an exploration project. Specific dryhole rates are used for horizontal drilling and the developing natural gas resources.

Figure 2-5: Economic Analysis Logic



In the advanced case, the dryhole rates may also incorporate technology improvements associated with exploration or drilling success.

$$REGDRYUE_{im} = \left(\frac{SUCEXP_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) * EXPLR\_FAC_{itech} \tag{2-1}$$

$$REGDRYUD_{im} = \left(\frac{SUCEXPD_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-2}$$

$$REGDRYKD_{im} = \left(\frac{SUCDEVE_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-3}$$

If evaluating horizontal continuity or horizontal profile, then,

$$REGDRYKD_{im} = \left(\frac{SUCCHDEV_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-4}$$

If evaluating developing natural gas resources, then,

$$REGDRYUD_{im} = ALATNUM_{ires} * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-5}$$

where

ITECH	=	Technology case number
IM	=	Region number
REGDRYUE	=	Project specific dryhole rate for undiscovered exploration (Wildcat)
REGDRYUD	=	Project specific dryhole rate for undiscovered development
REGDRYKD	=	Project specific dryhole rate for known field development
SUCEXPD	=	Regional dryhole rate for undiscovered development
ALATNUM	=	Variable representing the regional dryhole rate for known field development
SUCDEVE	=	Regional dryhole rate for undiscovered exploration (Wildcat)
SUCCDEVH	=	Dryhole rate for horizontal drilling
DRILL_FAC	=	Technology lever applied to dryhole rate
EXPLR_FAC	=	Technology factor applied to exploratory dryhole rate

Process specific depreciation schedule: The default depreciation schedule is based on an eight-year declining balance depreciation method. The user may select process-specific depreciation schedules for CO2 flooding, steam flooding, or water flooding in the input file.

Calculate the capital and operating costs for the project: The project costs are calculated for each technology case. The costs are specific to crude oil or natural gas resources. The results of the cost calculations, which include technical crude oil and natural gas production, as well as drilling costs, facilities costs, and operating costs, are then aggregated to the project level.

G & G factor: Calculates the geological and geophysical (G&G) factor for each technology case. This is added to the first year cost.

$$GG_{itech} = GG_{itech} + DRL\_CST_{itech} * INTANG\_M_{itech} * GG\_FAC \qquad (2\text{-}6)$$

where

GG_{itech}	=	Geophysical and Geological costs for the first year of the project
DRL_CST_{itech}	=	Total drilling cost for the first year of the project
$INTANG\_M_{itech}$	=	Energy Elasticity factor for intangible investments (first year)
GG_FAC	=	Portion of exploratory costs that is G&G costs

After the variables are aggregated, the technology case loop ends. At this point, the process specific capital costs, which apply to the entire project instead of the technology case, are calculated.

Cashflow Analysis: The model then conducts a cashflow analysis on the project and calculates the discounted rate of return. Economic Analysis is conducted using a standard cashflow routine described in Appendix A.

Calculate the discounted rate of return: Determines the projected rate of return for all investments and production. The cumulative investments and discounted after tax cashflow are used to calculate the investment efficiency for the project.

Calculate wells: The annual number of new and existing wells is calculated for the project. The model tracks five drilling categories:

- New production wells drilled
- New injection wells drilled
- Active production wells
- Active injection wells
- Shut in wells

The calculation of the annual well count depends on the number of existing production and injection wells as well as on the process and project-specific requirements to complete each drilling pattern developed.

Determine number of years a project is economic: The model calculates the last year of actual economic production. This is based on both the results of the cashflow analysis and the annual production in year specified by the analysis. The last year of production is used to determine the aggregation range to be used if the project is selected for development.

If the project is economic only in the first year, it will be considered uneconomic and unavailable for development at that time. If this occurs for an existing crude oil or natural gas project, the model will assume that all of the wells will be shut in.

Non-producing decline project: Determines if the existing crude oil or natural gas project is non-producing. If there is no production, then the end point for project aggregation is not calculated. This check applies only to the existing crude oil and natural gas projects

Ranking criteria: Ranks investment efficiency based on the discounted after tax cashflow over tangible and intangible investments.

Determine ranking criterion: The ranking criterion, specified by the user, is the parameter by which the projects will be sorted before development. Ranking criteria options include the project net present value, the rate of return for the project, and the investment efficiency.

Calculating Unit Costs

To conduct the cost analysis, the model calculates price adjustment factors as well as unit costs for all required capital and operating costs. Unit costs include the cost of drilling and completing a single well, producing one barrel of crude oil, or operating one well for a year. These costs are adjusted using the technology levers and CPI indices. After the development schedule for the project is determined and the economic life of a single well is calculated, the technical production and injection are determined for the project. Based on the project's development schedule and the technical production, the annual capital and operating costs are determined. In the final step, the process and resource specific capital and operating costs are calculated for the project. These steps are illustrated in figure 2-6.

The Onshore Lower 48 Oil and Gas Supply Submodule uses detailed project costs for economic calculations. There are three broad categories of costs used by the model: capital costs, operating costs, and other costs. These costs are illustrated in figure 2-7. Capital costs encompass the costs of drilling and equipment necessary for the production of crude oil and natural gas resources. Operating costs are used to calculate the full life cycle economics of the project. Operating costs consist of normal daily expenses and surface maintenance. Other cost parameters include royalty, state and federal taxes, and other required schedules and factors.

The calculations for capital costs and operating costs for both crude oil and natural gas are described in detail below. The capital and operating costs are used in the timing and economic module to calculate the lifecycle economics for all crude oil and natural gas projects.

There are two categories for these costs: costs that are applied to all processes, thus defined as *resource independent*, and the process-specific costs, or *resource dependent* costs. Resource dependent costs are used to calculate the economics for existing, reserves growth, and exploration projects. The capital costs for both crude oil and natural gas are calculated first, followed by the resource independent costs, and then the resource dependent costs.

The resource independent and resource dependent costs applied to each of the crude oil and natural gas processes are detailed in tables 2-2 and 2-3 respectively.

Figure 2-6: Project Cost Calculation Procedure

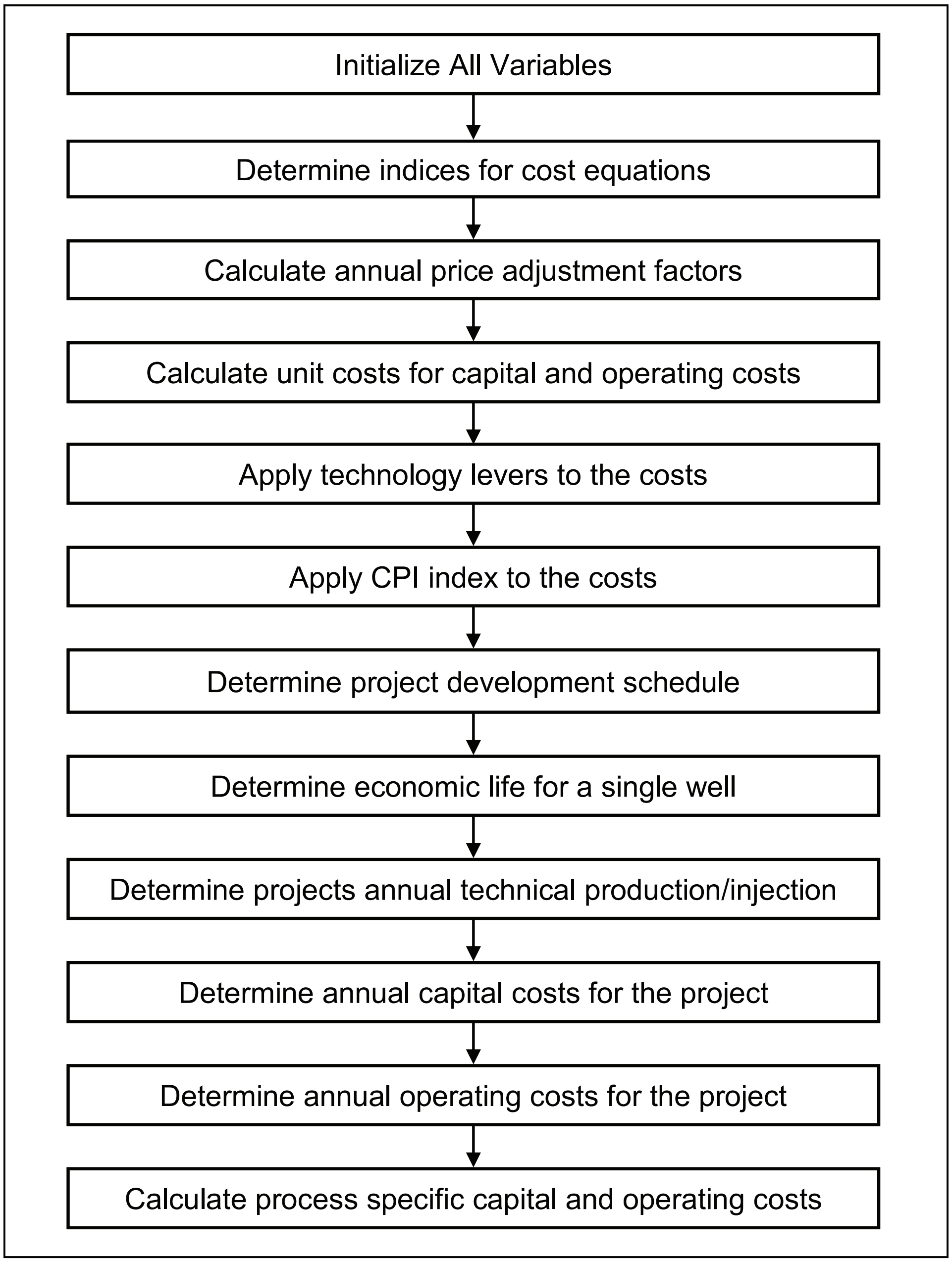


Figure 2-7: Cost Data Types and Requirements

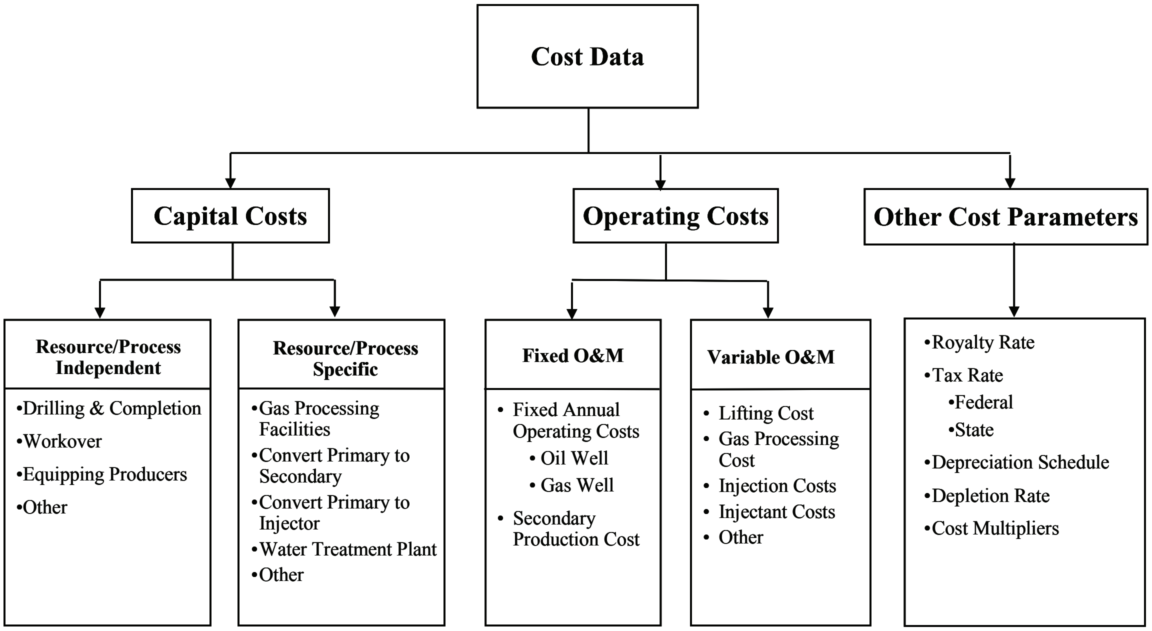


Table 2-2: Costs Applied to Crude Oil Processes

	Capital Cost for Oil	Existing	Water Flooding	CO2 Flooding	Steam Flooding	Polymer Flooding	Infill Drilling	Profile Modification	Undiscovered
Resource Independent	Vertical Drilling Cost	v	v	v	v	V	v	v	v
	Horizontal Drilling Cost								
	Drilling Cost for Dryhole	v	v	v	v	V	v	v	v
	Cost to Equip a Primary Producer		v	v	v	V	v	v	v
	Workover Cost		v	v	v	V	v	v	v
	Facillities Upgrade Cost		v	v	v	V	v	v	
	Fixed Annual Cost for Oil Wells	v	v	v	v	V	v	v	v
	Fixed Annual Cost for Secondary Production		v	v	v	V	v	v	v
	Lifting Cost		v	v	v	V	v	v	v
	O & M Cost for Active Patterns		v			V		v	
	Variable O & M Costs	v	v	v	v	V	v	v	v
	Socondary Workover Cost		v	v	v	V	v	v	v
Resource Dependent	Cost of Water Handling Plant		v			V		v	
	Cost of Chemical Plant					V			
	CO2 Recycle Plant			v					
	Cost of Injectant					V			
	Cost to Convert a Primary to Secondary Well		v	v	v	V	v	v	v
	Cost to Convert a Producer to an Injector		v	v	v	V	v	v	v
	Fixed O & M Cost for Secondary Operations		v	v	v	V	v	v	v
	Cost of a Water Injection Plant		v						
	O & M Cost for Active Patterns per Year		v			V		v	
	Cost to Inject CO2			v					
	King Factor				v				
	Steam Manifolds Cost				v				
	Steam Generators Cost				v				
	Cost to Inject Poloymer					V		v	

Table 2-3: Costs Applied to Natural Gas Processes

	Capital Costs for Gas	Conventional Radial Gas	Water Drive	Tight Sands	Coal/Shale Gas	Undiscovered Conventional
Resource Independent	Vertical Drilling Cost	v	v	v	v	v
	Horizontal Drilling Cost	v	v	v	v	v
	Drilling Cost for Dryhole	v	v	v	v	v
	Gas Facilities Cost	v	v	v	v	v
	Fixed Annual Costs for Gas Wells	v	v	v	v	v
	Gas Stimulation Costs	v	v	v	v	v
	Overhead Costs	v	v	v	v	v
	Variable O & M Cost	v	v	v	v	v
Resource Dependent	Gas Processing and Treatment Facilities	v	v	v	v	v

The following section details the calculations used to calculate the capital and operating costs for each crude oil and natural gas project. The specific coefficients are econometrically estimated according to the corresponding equations in Appendix 2.B.

Cost Multipliers

Cost multipliers are used to capture the impact on capital and operating costs associated with changes in energy prices. OLOGSS calculates cost multipliers for tangible and intangible investments, operating costs, and injectants (polymer and CO_2). The methodology used to calculate the multipliers is based on the National Energy Technology Laboratory (NETL's) Comprehensive Oil and Gas Analysis Model as well as the 1984 Enhanced Oil Recovery Study completed by the National Petroleum Council.

The multipliers for operating costs and injectant are applied while calculating project costs. The investment multipliers are applied during the cashflow analysis. The injectant multipliers are held constant for the analysis period while the others vary with changing crude oil and natural gas prices.

Operating Costs for Crude Oil: Operating costs are adjusted by the change between current crude oil prices and the base crude oil price. If the crude oil price in a given year falls below a pre-established minimum price, the adjustment factor is calculated using the minimum crude oil price.

$$\text{TERM} = \left(\frac{\text{OILPRICE}_{\text{iyr}} - \text{BASEOIL}}{\text{BASEOIL}} \right) \tag{2-7}$$

$$\text{INTANG\_M}_{\text{iyr}} = 1.0 + (\text{OMULT\_INT} * \text{TERM}) \tag{2-8}$$
$$\text{TANG\_M}_{\text{iyr}} = 1.0 + (\text{OMULT\_TANG} * \text{TERM}) \tag{2-9}$$
$$\text{OAM\_M}_{\text{iyr}} = 1.0 + (\text{OMULT\_OAM} * \text{TERM}) \tag{2-10}$$

where

IYR	=	Year
TERM	=	Fractional change in crude oil prices (from base price)
BASEOIL	=	Base crude oil price used for normalization of capital and operating costs
OMULT_INT	=	Coefficient for intangible crude oil investment factor
OMULT_TANG	=	Coefficient for tangible crude oil investment factor
OMULT_OAM	=	Coefficient for O & M factor
INTANG_M	=	Annual energy elasticity factor for intangible investments
TANG_M	=	Annual energy elasticity factor for tangible investments
OAM_M	=	Annual energy elasticity factor for crude oil O & M

Cost Multipliers for Natural Gas:

$$TERM = \left(\frac{GASPRICEC_{iyr} - BASEGAS}{BASEGAS} \right) \tag{2-11}$$

$$TANG\_M_{iyr} = 1.0 + (GMULT\_TANG * TERM) \tag{2-12}$$

$$INTANG\_M_{iyr} = 1.0 + (GMULT\_INT * TERM) \tag{2-13}$$

$$OAM\_M_{iyr} = 1.0 + (GMULT\_OAM * TERM) \tag{2-14}$$

where

GASPRICEC	=	Annual natural gas price
IYR	=	Year
TERM	=	Fractional change in natural gas prices
BASEGAS	=	Base natural gas price used for normalization of capital and operating costs
GMULT_INT	=	Coefficient for intangible natural gas investment factor
GMULT_TANG	=	Coefficient for tangible natural gas investment factor
GMULT_OAM	=	Coefficient for O & M factor
INTANG_M	=	Annual energy elasticity factor for intangible investments
TANG_M	=	Annual energy elasticity factor for tangible investments
OAM_M	=	Annual energy elasticity factor for crude oil O & M

Cost Multipliers for Injectant:

In the first year of the project:

$$FPLY = 1.0 + (0.3913 * TERM) \tag{2-15}$$

$$FCO2 = \frac{0.5 + 0.013 * BASEOIL * (1.0 + TERM)}{0.5 + 0.013 * BASEOIL} \tag{2-16}$$

where

TERM	=	Fractional change in crude oil prices
BASEOIL	=	Base crude oil price used for normalization of capital and operating costs
FPLY	=	Energy elasticity factor for polymer

FCO2	=	Energy elasticity factor for natural CO_2 prices

Resource Independent Capital Costs for Crude Oil

Resource independent capital costs are applied to both crude oil and natural gas projects, regardless of the recovery method applied. The major resource independent capital costs are as follows: drilling and completion costs, the cost to equip a new or primary producer, and workover costs.

Drilling and Completion Costs: Drilling and completion costs incorporate the costs to drill and complete a crude oil or natural gas well (including tubing costs), and logging costs. These costs do not include the cost of drilling a dryhole/wildcat during exploration. OLOGSS uses a separate cost estimator, documented below, for dryholes drilled. Vertical well drilling costs include drilling and completion of vertical, tubing, and logging costs. Horizontal well costs include costs for drilling and completing a vertical well and the horizontal laterals.

Horizontal Drilling for Crude Oil:

$$DWC\_W = OIL\_DWCK_{r,d} + (OIL\_DWCA_{r,d} * DEPTH^2) + (OIL\_DWCB_{r,d} * DEPTH^2 * NLAT) + (OIL\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}17)$$

Vertical Drilling for Crude Oil:

$$DWC\_W = OIL\_DWCK_{r,d} + (OIL\_DWCA_{r,d} * DEPTH) + (OIL\_DWCB_{r,d} * DEPTH^2) + (OIL\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}18)$$

where

DWC_W	=	Cost to drill and complete a crude oil well (K$/Well)
r	=	Region number
d	=	Depth category number
OIL_DWCA, B, C, K	=	Coefficients for crude oil well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Horizontal Drilling for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH^2) + (DRY\_DWCB_{r,d} * DEPTH^2 * NLAT) + (DRY\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}19)$$

Vertical Drilling for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH) + (DRY\_DWCB_{r,d} * DEPTH^2) + (DRY\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}20)$$

where

DRY_W	=	Cost to drill a dry well (K$/Well)
R	=	Region number
D	=	Depth category number
DRY_DWCA, B, C, K	=	Coefficients for dry well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Cost to Equip a New Producer: The cost of equipping a primary producing well includes the production equipment costs for primary recovery.

$$NPR\_W = NPRK_{r,d} + (NPRA_{r,d} * DEPTH) + (NPRB_{r,d} * DEPTH^2) + (NPRC_{r,d} * DEPTH^3) \quad (2\text{-}21)$$

where

NPR_W	=	Cost to equip a new producer (K$/Well)
R	=	Region number
D	=	Depth category number
NPRA, B, C, K	=	Coefficients for new producer equipment cost equation
DEPTH	=	Well depth

Workover Costs: Workover, also known as stimulation is done every 2-3 years to increase the productivity of a producing well. In some cases workover or stimulation of a wellbore is required to maintain production rates.

$$WRK\_W = WRKK_{r,d} + (WRKA_{r,d} * DEPTH) + (WRKB_{r,d} * DEPTH^2) + (WRKC_{r,d} * DEPTH^3) \quad (2\text{-}22)$$

Where,

WRK_W	=	Cost for a well workover (K$/Well)
R	=	Region number
D	=	Depth category number
WRKA, B, C, K	=	Coefficients for workover cost equation
DEPTH	=	Well depth

Facilities Upgrade Cost: Additional cost of equipment upgrades incurred when converting a primary producing well to a secondary resource recovery producing well. Facilities upgrade costs consist of plant costs and electricity costs.

$$FAC\_W = FACUPK_{r,d} + (FACUPA_{r,d} * DEPTH) + (FACUPB_{r,d} * DEPTH^2) + (FACUPC_{r,d} * DEPTH^3) \quad (2\text{-}23)$$

where

FAC_W	=	Well facilities upgrade cost (K$/Well)
R	=	Region number
D	=	Depth category number
FACUPA, B, C, K	=	Coefficients for well facilities upgrade cost equation

DEPTH = Well depth

Resource Independent Capital Costs for Natural Gas

Drilling and Completion Costs: Drilling and completion costs incorporate the costs to drill and complete a crude oil or natural gas well (including tubing costs), and logging costs. These costs do not include the cost of drilling a dryhole/wildcat during exploration. OLOGSS uses a separate cost estimator, documented below, for dryholes drilled. Vertical well drilling costs include drilling and completion of vertical, tubing, and logging costs. Horizontal well costs include costs for drilling and completing a vertical well and the horizontal laterals.

Vertical Drilling Costs:

$$DWC\_W = GAS\_DWCK_{r,d} + (GAS\_DWCA_{r,d} * DEPTH) + (GAS\_DWCB_{r,d} * DEPTH^2) + (GAS\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}24)$$

Horizontal Drilling Costs:

$$DWC\_W = GAS\_DWCK_{r,d} + (GAS\_DWCA_{r,d} * DEPTH^2) + (GAS\_DWCB_{r,d} * DEPTH^2 * NLAT) + (GAS\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}25)$$

Where,

DWC_W	=	Cost to drill and complete a natural gas well (K$/Well)
R	=	Region number
D	=	Depth category number
GAS_DWCA, B, C, K	=	Coefficients for natural gas well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Vertical Drilling Costs for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH) + (DRY\_DWCB_{r,d} * DEPTH^2) + (DRY\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}26)$$

Horizontal Drilling Costs for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH^2) + (DRY\_DWCB_{r,d} * DEPTH^2 * NLAT) + (DRY\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}27)$$

where

DRY_W	=	Cost to drill a dry well (K$/Well)
R	=	Region number
D	=	Depth category number
DRY_DWCA, B, C, K	=	Coefficients for dry well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Facilities Cost: Additional cost of equipment upgrades incurred when converting a primary producing well to a secondary resource recovery producing well. Facilities costs consist of flowlines and connections, production package costs, and storage tank costs.

$$FWC\_W_{iyr} = FACGK_{r,d} + (FACGA_{r,d} * DEPTH) + (FACGB_{r,d} * PEAKDAILY\_RATE) + (FACGC_{r,d} * DEPTH * PEAKDAILY\_RATE) \quad (2\text{-}28)$$

where

FWC_W	=	Facilities cost for a natural gas well (K$/Well)
R	=	Region number
D	=	Depth category number
FACGA, B, C, K	=	Coefficients for facilities cost equation
DEPTH	=	Well depth
PEAKDAILY_RATE	=	Maximum daily natural gas production rate

Fixed Annual Operating Costs: The fixed annual operating costs are applied to natural gas projects in decline curve analysis.

$$FOAMG\_W = OMGK_{r,d} + (OMGA_{r,d} * DEPTH) + (OMGB_{r,d} * PEAKDAILY\_RATE) + (OMGC_{r,d} * DEPTH * PEAKDAILY\_RATE) \quad (2\text{-}29)$$

where

FOAMG_W	=	Fixed annual operating costs for natural gas (K$/Well)
R	=	Region number
D	=	Depth category number
OMGA, B, C, K	=	Coefficients for fixed annual O & M cost equation for natural gas
DEPTH	=	Well depth
PEAKDAILY_RATE	=	Maximum daily natural gas production rate

Resource Independent Annual Operating Costs for Crude Oil

Fixed Operating Costs: The fixed annual operating costs are applied to crude oil projects in decline curve analysis.

$$OMO\_W = OMOK_{r,d} + (OMOA_{r,d} * DEPTH) + (OMOB_{r,d} * DEPTH^2) + (OMOC_{r,d} * DEPTH^3) \quad (2\text{-}30)$$

where

OMO_W	=	Fixed annual operating costs for crude oil wells (K$/Well)
R	=	Region number
D	=	Depth category number
OMOA, B, C, K	=	Coefficients for fixed annual operating cost equation for crude oil
DEPTH	=	Well depth

Annual Costs for Secondary Producers: The direct annual operating expenses include costs in the following major areas: normal daily expenses, surface maintenance, and subsurface maintenance.

$$OPSEC\_W = OPSECK_{r,d} + (OPSECA_{r,d} * DEPTH) + (OPSECB_{r,d} * DEPTH^2) + (OPSECC_{r,d} * DEPTH^3) \quad (2\text{-}31)$$

where

OPSEC_W	=	Fixed annual operating cost for secondary oil operations (K$/Well)
R	=	Region number
D	=	Depth category number
OPSECA, B, C, K	=	Coefficients for fixed annual operating cost for secondary oil operations
DEPTH	=	Well depth

Lifting Costs: Incremental costs are added to a primary and secondary flowing well. These costs include pump operating costs, remedial services, workover rig services and associated labor.

$$OML\_W = OMLK_{r,d} + (OMLA_{r,d} * DEPTH) + (OMLB_{r,d} * DEPTH^2) + (OMLC_{r,d} * DEPTH^3) \quad (2\text{-}32)$$

where

OML_W	=	Variable annual operating cost for lifting (K$/Well)
R	=	Region number
D	=	Depth category number
OMLA, B, C, K	=	Coefficients for variable annual operating cost for lifting equation
DEPTH	=	Well depth

Secondary Workover: Secondary workover, also known as stimulation is done every 2-3 years to increase the productivity of a secondary producing well. In some cases secondary workover or stimulation of a wellbore is required to maintain production rates.

$$SWK\_W = OMSWRK_{r,d} + (OMSWR\ A_{r,d} * DEPTH) + (OMSWR\ B_{r,d} * DEPTH^2) + (OMSWR\ C_{r,d} * DEPTH^3) \quad (2\text{-}33)$$

where

SWK_W	=	Secondary workover costs (K$/Well)
R	=	Region number
D	=	Depth category number
OMSWRA, B, C, K	=	Coefficients for secondary workover costs equation
DEPTH	=	Well depth

Stimulation Costs: Workover, also known as stimulation is done every 2-3 years to increase the productivity of a producing well. In some cases workover or stimulation of a wellbore is required to maintain production rates.

$$STIM\_W = \left(\frac{STIM\_A + STIM\_B * DEPTH}{1000} \right) \quad (2\text{-}34)$$

where

STIM_W	=	Oil stimulation costs (K$/Well)
STIM_A, B	=	Stimulation cost equation coefficients
DEPTH	=	Well depth

Resource Dependent Capital Costs for Crude Oil

Cost to Convert a Primary Well to a Secondary Well: These costs consist of additional costs to equip a primary producing well for secondary recovery. The cost of replacing the old producing well equipment includes costs for drilling and equipping water supply wells but excludes tubing costs.

$$PSW\_W = PSWK_{r,d} + (PSWA_{r,d} * DEPTH) + (PSWB_{r,d} * DEPTH^2) + (PSWC_{r,d} * DEPTH^3) \quad (2\text{-}35)$$

where

PSW_W	=	Cost to convert a primary well into a secondary well (K$/Well)
R	=	Region number
D	=	Depth category number
PSWA, B, C, K	=	Coefficients for primary to secondary well conversion cost equation
DEPTH	=	Well depth

Cost to Convert a Producer to an Injector: Producing wells may be converted to injection service because of pattern selection and favorable cost comparison against drilling a new well. The conversion procedure consists of removing surface and sub-surface equipment (including tubing), acidizing and cleaning out the wellbore, and installing new 2- 7/8 inch plastic-coated tubing and a waterflood packer (plastic-coated internally and externally).

$$PSI\_W = PSIK_{r,d} + (PSIA_{r,d} * DEPTH) + (PSIB_{r,d} * DEPTH^2) + (PSIC_{r,d} * DEPTH^3) \quad (2\text{-}36)$$

where

PSI_W	=	Cost to convert a producing well into an injecting well (K$/Well)
R	=	Region number
D	=	Depth category number
PSIA, B, C, K	=	Coefficients for producing to injecting well conversion cost equation
DEPTH	=	Well depth

Cost of Produced Water Handling Plant: The capacity of the water treatment plant is a function of the maximum daily rate of water injected and produced (MBbl) throughout the life of the project.

$$PWP\_F = PWHP * \left(\frac{RMAXW}{365} \right) \tag{2-37}$$

where

PWP_F	=	Cost of the produced water handling plant (K$/Well)
PWHP	=	Produced water handling plant multiplier
RMAXW	=	Maximum pattern level annual water injection rate

Cost of Chemical Handling Plant (Non-Polymer): The capacity of the chemical handling plant is a function of the maximum daily rate of chemicals injected throughout the life of the project.

$$CHM\_F = CHMK * CHMA * \left(\frac{RMAXP}{365} \right)^{CHMB} \tag{2-38}$$

where

CHM_F	=	Cost of chemical handling plant (K$/Well)
CHMB	=	Coefficient for chemical handling plant cost equation
CHMK, A	=	Coefficients for chemical handling plant cost equation
RMAXP	=	Maximum pattern level annual polymer injection rate

Cost of Polymer Handling Plant: The capacity of the polymer handling plant is a function of the maximum daily rate of polymer injected throughout the life of the project.

$$PLY\_F = PLYPK * PLYPA * \left(\frac{RMAXP}{365} \right)^{0.6} \tag{2-39}$$

where

PLY_F	=	Cost of polymer handling plant (K$/Well)
PLYPK, A	=	Coefficients for polymer handling plant cost equation
RMAXP	=	Maximum pattern level annual polymer injection rate

Cost of CO_2 Recycling Plant: The capacity of a recycling/injection plant is a function of the maximum daily injection rate of CO_2 (Mcf) throughout the project life. If the maximum CO_2 rate equals or exceeds 60 MBbl/Day then the costs are divided into two separate plant costs.

$$CO2\_F = CO2rk * \left(\frac{0.75 * RMAXP}{365} \right)^{CO2RB} \tag{2-40}$$

where,

CO2_F	=	Cost of CO_2 recycling plant (K$/Well)
CO2RK, CO2RB	=	Coefficients for CO_2 recycling plant cost equation
RMAXP	=	Maximum pattern level annual CO_2 injection rate

Cost of Steam Manifolds and Pipelines: Cost to install and maintain steam manifolds and pipelines for steam flood enhanced oil recovery project.

$$STMM\_F = TOTPAT * PATSZE * STMMA \tag{2-41}$$

where

STMM_F	=	Cost for steam manifolds and generation (K$)
TOTPAT	=	Total number of patterns in the project
PATSZE	=	Pattern size (Acres)
STMMA	=	Steam manifold and pipeline cost (per acre)

Resource Dependant Annual Operating Costs for Crude Oil

Injection Costs: Incremental costs are added for secondary injection wells. These costs include pump operating, remedial services, workover rig services, and associated labor.

$$OPINJ\_W = OPINJK_{r,d} + (OPINJA_{r,d} * DEPTH) + (OPINJ\ B_{r,d} * DEPTH^2) + (OPINJ\ C_{r,d} * DEPTH^3) \tag{2-42}$$

where

OPINJ_W	=	Variable annual operating cost for injection (K$/Well)
R	=	Region number
D	=	Depth category number
OPINJA, B, C, K	=	Coefficients for variable annual operating cost for injection equation
DEPTH	=	Well depth

Injectant Cost: The injectant costs are added for the secondary injection wells. These costs are specific to the recovery method selected for the project. Three injectants are modeled: polymer, CO_2 from natural sources, and CO_2 from industrial sources.

Polymer Cost:

$$POLYCOST = POLYCOST * FPLY \tag{2-43}$$

where

POLYCOST	=	Cost of polymer ($/Lb)
FPLY	=	Energy elasticity factor for polymer

Natural CO_2 Cost: Cost to drill, produce and ship CO_2 from natural sources, namely CO_2 fields in Western Texas.

$$CO2COST = CO2K + (CO2B * OILPRICEO(1)) \tag{2-44}$$

$$CO2COST = CO2COST * CO2PR(IST) \tag{2-45}$$

where

CO2COST	=	Cost of natural CO_2 ($/Mcf)
IST	=	State identifier
CO2K, CO2B	=	Coefficients for natural CO_2 cost equation
OILPRICEO(1)	=	Crude oil price for first year of project analysis
CO2PR	=	State CO_2 cost multiplier used to represent changes in cost associated with transportation outside of the Permian Basin

Industrial CO_2 Cost: Cost to capture and transport CO_2 from industrial sources. These costs include the capture, compression to pipeline pressure, and the transportation to the project site via pipeline. The regional costs, which are specific to the industrial source of CO_2, are exogenously determined and provided in the input file.

Industrial CO_2 sources include

- Hydrogen Plants
- Ammonia Plants
- Ethanol Plants
- Cement Plants
- Hydrogen Refineries
- Power Plants
- Natural Gas Processing Plants
- Coal to Liquids

After unit costs have been calculated for the project, they are adjusted using technology levers as well as CPI multipliers. Two types of levers are applied to the costs. The first is the fractional change in cost associated with a new technology. The second is the incremental cost associated with implementing the new technology. These factors are determined by the model user. As an example,

$$NPR\_W = (NPR\_W * CHG\_FAC\_FAC(ITECH)) + CST\_FAC\_FAC(ITECH) \qquad (2\text{-}46)$$

where,

NPR_W	=	Cost to equip a new oil producer (K$/well)
CHG_FAC_FAC	=	Fractional change in cost associated with technology improvements
CST_FAC_FAC	=	Incremental cost to apply the new technology
ITECH	=	Technology case (Base or Advanced)

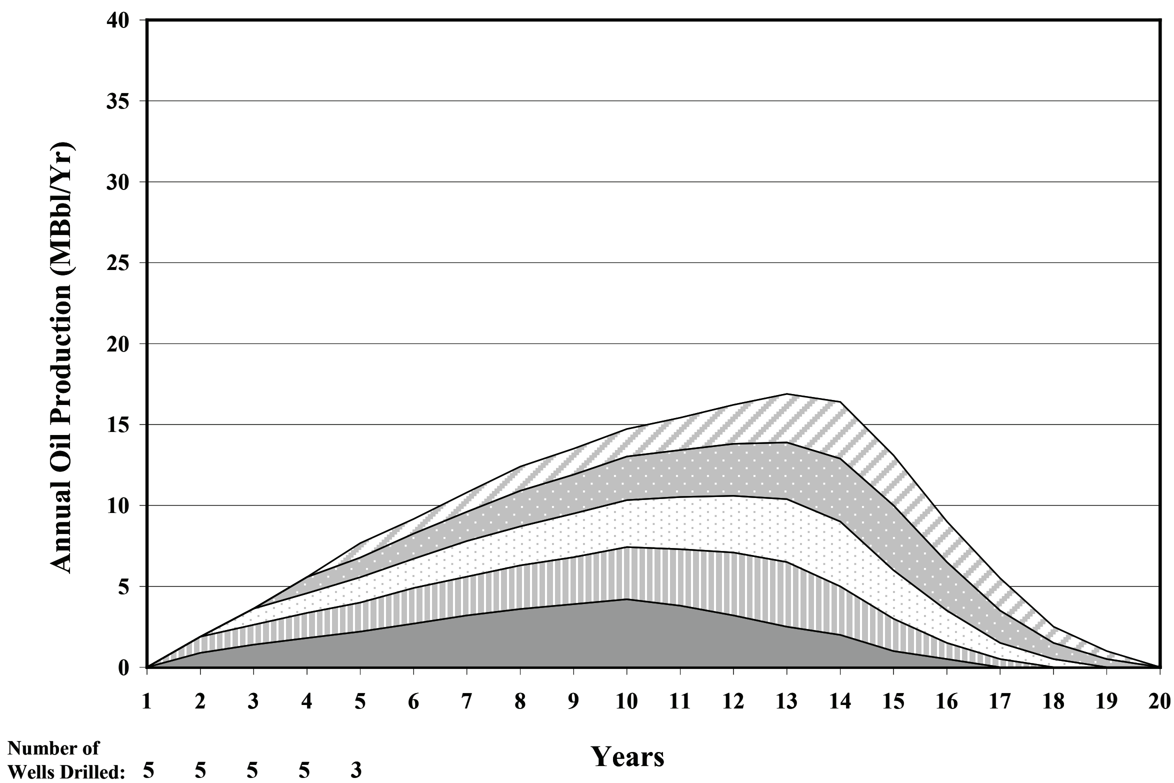
Determining Technical Production

The development schedule algorithms determine how the project's development over time will be modeled. They calculate the number of patterns initiated per year and the economic life of the well. The economic life is the number of years in which the revenue from production exceeds the costs required to produce the crude oil and natural gas.

The model then aggregates the well-level production of crude oil, natural gas, water, and injectant based upon the pattern life and number of wells initiated each year. The resulting profile is the technical production for the project.

Figure 2-8 shows the crude oil production for one project over the course of its life. The graph shows a hypothetical project. In this scenario patterns are initiated for five years. Each shaded area is the annual technical production associated with the initiated patterns.

Figure 2-8: Calculating Project Level Technical Production



The first step in modeling the technical production is to calculate the number of patterns drilled each year. The model uses several factors in calculating the development schedule:

- Potential delays between the discovery of the project and actual initiation
- The process modeled
- The resource access – the number of patterns developed each year is reduced if the resource is subject to cumulative surface use limitations
- The total number of patterns in the project
- The crude oil and natural gas prices
- The user specified maximum and minimum number of patterns developed each year
- The user specified percentage of the project to be developed each year
- The percentage of the project which is using base or advanced technology.

These apply to the EOR/ASR projects as well as the undiscovered and currently developing ones. The projects in existing fields and reservoirs are assumed to have all of their patterns – the number of active wells – developed in the first year of the project.

After calculating the number of patterns initiated each year, the model calculates the number of patterns which are active for each year of the project life.

Production Profile of the Project: For all EOR/ASR, undiscovered, and developing processes, the project level technical production is calculated using well-level production profiles. For infill projects, the production is doubled because the model assumes that there are two producers in each pattern.

$$OILPROD_{iyr1} = OILPROD_{iyr1} + (OPROD_{kyr} * PATN_{iyr}) \tag{2-47}$$
$$GASPROD_{iyr1} = OILPROD_{iyr1} + (GPROD_{kyr} * PATN_{iyr}) \tag{2-48}$$
$$NGLPROD_{iyr1} = NGLPROD_{iyr1} + (NPROD_{kyr} * PATN_{iyr}) \tag{2-49}$$
$$WATPROD_{iyr1} = WATPROD_{iyr1} + (WPROD_{kyr} * PATN_{iyr}) \tag{2-50}$$
$$TOTINJ_{iyr1} = TOTINJ_{iyr1} + (OINJ_{kyr} * PATN_{iyr}) \tag{2-51}$$
$$WATINJ_{iyr1} = WATINJ_{iyr1} + (WINJ_{kyr} * PATN_{iyr}) \tag{2-52}$$
$$TORECY_{iyr1} = TORECY_{iyr1} + (ORECY_{kyr} * PATN_{iyr}) \tag{2-53}$$
$$SUMP_{iyr1} = SUMP_{iyr1} + PATN_{iyr} \tag{2-54}$$

where

IYR1	=	Number of years
IYR	=	Year of project development
JYR	=	Number of years the project is developed
KYR	=	Year (well level profile)
LYR	=	Last project year in which pattern level profile is applied
OPROD	=	Pattern level annual crude oil production
GPROD	=	Pattern level annual natural gas production
NPROD	=	Pattern level annual NGLl production
WPROD	=	Pattern level annual water production
WINJ	=	Pattern level annual water injection
OINJ	=	Pattern level annual injectant injection
ORECY	=	Pattern level annual injectant recycled
PATN	=	Number of patterns initiated each year
SUMP	=	Cumulative number of patterns developed
OILPROD	=	Project level annual crude oil production
GASPROD	=	Project level annual natural gas production
NGLPROD	=	Project level annual NGL production
WATPROD	=	Project level annual water production
WATINJ	=	Project level annual water injection
TOTINJ	=	Project level annual injectant injection
TORECY	=	Project level annual injectant recycled

Reviewer's note: The equations above are confusing, because the same variable appears on the LHS and RHS. I'm guessing that the variable is simply being incremented on an annual basis, i.e., that the first equation should read something like

In any case, please clarify what is happening in the equations and use a new variable name on the LHS.

Resource Accounting

OLOGSS incorporates a complete and representative description of the processes by which crude oil and natural gas in the technically recoverable resource base[1] are converted to proved reserves.[2]

OLOGSS distinguishes between drilling for new fields (new field wildcats) and drilling for additional deposits within old fields (other exploratory and developmental wells). This enhancement recognizes important differences in exploratory drilling, both by its nature and in its physical and economic returns. New field wildcats convert resources in previously undiscovered fields[3] into both proved reserves (as new discoveries) and inferred reserves.[4] Other exploratory drilling and developmental drilling add to proved reserves from the stock of inferred reserves. The phenomenon of reserves appreciation is the process by which initial assessments of proved reserves from a new field discovery grow over time through extensions and revisions.

End of Year Reserves: The model calculates two types of end of year (EOY) reserves at the project level: inferred reserves and proved reserves. Inferred reserves are calculated as the total technical production minus the technical production from patterns initiated through a particular year. Proved reserves are calculated as the technical production from wells initiated through a particular year minus the cumulative production from those patterns.

Inferred reserves = total technical production – technical production for wells initiated

$$\text{airsvoil(ires, n)} = \sum_{`i=1}^{\text{max\_yr}}\left[\sum_{j=1}^{\text{ilife}}(\text{oprod}(j)) \times \text{patn}(i)\right] - \sum_{i=1}^{n}\left[\sum_{j=1}^{\text{ilife}}(\text{oprod}(j)) \times \text{patn}(i)\right] \tag{2-55}$$

$$\text{airsvgas(ires, n)} = \sum_{`i=1}^{\text{max\_yr}}\left[\sum_{j=1}^{\text{ilife}}(\text{gprod}(j)) \times \text{patn}(i)\right] - \sum_{i=1}^{n}\left[\sum_{j=1}^{\text{ilife}}(\text{gprod}(j)) \times \text{patn}(i)\right]$$

(2-56)

Reviewers note: It's not clear what "ires" is above. Also, it looks like all of these equations can be simplified by writing the outer sums from n+1 to max_yr, e.g.,

Proved reserves = technical production for patterns initiated – cumulative production

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[1]*Technically recoverable resources* are those volumes considered to be producible with current recovery technology and efficiency but without reference to economic viability. Technically recoverable volumes include proved reserves, inferred reserves, as well as undiscovered and other unproved resources. These resources may be recoverable by techniques considered either conventional or unconventional.

[2]*Proved reserves* are the estimated quantities that analyses of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[3]*Undiscovered resources* are located outside of oil and gas fields, in which the presence of resources has been confirmed by exploratory drilling, and thus exclude reserves and reserve extensions; however, they include resources from undiscovered pools within confirmed fields to the extent that such resources occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[4]*Inferred reserves* are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

$$\text{aresvoil(ires, n)} = \sum_{`i=1}^{n}\left[\sum_{j=1}^{ilife}(\text{oprod}(j)) \times \text{patn}(i)\right] - \sum_{i=1}^{n}\left[\sum_{j=1}^{n}(\text{oprod}(j)) \times \text{patn}(i)\right] \quad (2\text{-}57)$$

$$\text{aresvgas(ires, n)} = \sum_{`i=1}^{n}\left[\sum_{j=1}^{ilife}(\text{gprod}(j)) \times \text{patn}(i)\right] - \sum_{i=1}^{n}\left[\sum_{j=1}^{n}(\text{gprod}(j)) \times \text{patn}(i)\right] \quad (2\text{-}58)$$

where,

I, J	=	Years
N	=	Current year evaluated
ILIFE	=	Pattern life
MAX_YR	=	Maximum number of years
OPROD	=	Pattern level annual crude oil production
GPROD	=	Pattern level annual natural gas production
PATN	=	Number of patterns developed each year
AIRSVOIL	=	Annual inferred crude oil reserves
AIRSVGAS	=	Annual inferred natural gas reserves
ARESVOIL	=	Annual proved oil reserves
ARESVGAS	=	Annual proved natural gas reserves

For existing crude oil and natural gas projects, the model calculates the proved reserves. For these processes, the proved reserves are defined as the total technical production divided by the life of the project.

Calculating Project Costs

The model uses four drilling categories for the calculation of drilling and facilities costs. These categories are:

- New producers
- New injectors
- Conversions of producers to injectors
- Conversions of primary wells to secondary wells.

The number of ??? in each category required for the pattern is dependent upon the process and the project.

Project Level Process Independent Costs

Drilling costs and facility costs are determined at the project level.

Drilling Costs: Drilling costs are calculated using one of four approaches, depending on the resource and recovery process. These approaches apply to the following resources:

- Undiscovered crude oil and natural gas
- Existing crude oil and natural gas fields
- EOR/ASR projects
- Developing natural gas projects

For undiscovered crude oil and natural gas resources: The first well drilled in the first year of the project is assumed to be a wildcat well. The remaining wells are assumed to be undiscovered development wells. This is reflected in the application of the dryhole rates.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUE_R) * 1.0 * XPP1 \quad (2\text{-}59)$$

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUD_R) * (PATN_{iyr} - 1 * XPP1) \quad (2\text{-}60)$$

For existing crude oil and natural gas fields: As the field is already established, the developmental dryhole rate is used.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYKD_R) * (PATDEV_{ires,iyr,\,itech} * XPP1) \quad (2\text{-}61)$$

For EOR/ASR Projects: As the project is in an established and known field, the developmental dryhole rate is used.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYKD_R) * (PATN_{iyr} * XPP1) \quad (2\text{-}62)$$

For developing natural gas projects: As the project is currently being developed, it is assumed that the wildcat well(s) have previously been drilled. Therefore, the undiscovered developmental dryhole rate is applied to the project.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUD_R) * (PATN_{iyr} * XPP1) \quad (2\text{-}63)$$

where

IRES	=	Project index number
IYR	=	Year
R	=	Region
PATDEV	=	Number of patterns initiated each year for base and advanced technology cases
PATN	=	Annual number of patterns initiated
DRL_CST2	=	Technology case specific annual drilling cost
DWC_W	=	Cost to drill and complete a well
DRY_W	=	Cost to drill a dryhole
REGDRYUE	=	Dryhole rate for undiscovered exploration (wildcat)
REGDRYUD	=	Dryhole rate for undiscovered development
REGDRYKD	=	Dryhole rate for known fields development
XPP1	=	Number of producing wells drilled per pattern

Facilities Costs: Facilities costs depend on both the process and the resource. Five approaches are used to calculate the facilities costs for the project.

For undiscovered and developing natural gas projects:

$$FACCOST_{iyr} = FACCOST_{iyr} + (FWC\_W * PATN_{iyr} * XPP1) \quad (2\text{-}64)$$

For existing natural gas fields:

$$FACCOST_{iyr} = FACCOST_{iyr} + (FWC\_W * (PATDEV_{IRES,iyr,\ itech}) * XPP1) \quad (2\text{-}65)$$

For undiscovered continuous crude oil:

$$FACCOST_{iyr} = FACCOST_{iyr} + (NPR\_W * PATN_{iyr} * XPP1) \quad (2\text{-}66)$$

For existing crude oil fields:

$$\begin{aligned} FACCOST_{iyr} = FACCOST_{iyr} &+ (PSW\_W * (PATDEV_{IRES,iyr,\ itech}) * XPP4) \\ &+ (PSI\_W * PATDEV_{IRES,iyr,\ itech} * XPP3) \\ &+ (FAC\_W * PATDEV_{IRES,iyr,\ itech} * (XPP1 + XPP2)) \end{aligned} \quad (2\text{-}67)$$

For undiscovered conventional crude oil and EOR/ASR projects:

$$\begin{aligned} FACCOST_{iyr} = FACCOST_{iyr} &+ (PSW\_W * PATN_{iyr} * XPP4) \\ &+ (PSI\_W * PATN_{iyr} * XPP3) + (FAC\_W * PATN_{iyr} * (XPP1 + XPP2)) \end{aligned} \quad (2\text{-}68)$$

where

IYR	=	Year
IRES	=	Project index number
ITECH	=	Technology case
PATN	=	Number of patterns initiated each year for the technology case being evaluated
PATDEV	=	Number of patterns initiated each year for base and advanced technology cases
XPP1	=	Number of new production wells drilled per pattern
XPP2	=	Number of new injection wells drilled per pattern
XPP3	=	Number of producers converted to injectors per pattern
XPP4	=	Number of primary wells converted to secondary wells per pattern
FAC_W	=	Crude oil well facilities upgrade cost
NPR_W	=	Cost to equip a new producer
PSW_W	=	Cost to convert a primary well to a secondary well
PSI_W	=	Cost to convert a production well to an injection well
FWC_W	=	Natural gas well facilities cost
FACCOST	=	Annual facilities cost for the well

Injectant Cost Added to Operating and Maintenance: The cost of injectant is calculated and added to the operating and maintenance costs.

$$INJ_{iyr} = INJ_{iyr} + INJ\_OAM1 * WATINJ_{iyr} \quad (2\text{-}69)$$

where

IYR	=	Year

INJ = Annual injection cost
INJ_OAM1 = Process specific cost of injection ($/Bbl)
WATINJ = Annual project level water injection

Fixed Annual Operating Costs for Crude Oil:
For CO_2 EOR:

$$AOAM_{iyr} = AOAM_{iyr} + OPSEC\_W * SUMP_{iyr} \tag{2-70}$$

For undiscovered conventional crude oil:

Fixed annual operating costs for secondary oil wells are assumed to be zero.

For all crude oil processes except CO_2 EOR:

$$AOAM_{iyr} = AOAM_{iyr} + (OMO\_W * XPATN_{iyr}) + (OPSEC\_W * XPATN_{iyr}) \tag{2-71}$$

Fixed Annual Operating Costs for Natural Gas:
For existing natural gas fields:

$$AOAM_{iyr} = AOAM_{iyr} + (FOAMG\_W * OAM\_M_{iyr} * XPATN_{iyr}) \tag{2-72}$$

For undiscovered and developing natural gas resources:

$$AOAM_{iyr} = AOAM_{iyr} + (FOAMG\_W * OAM\_M_{iyr} * XPATN_{iyr}) * XPP1 \tag{2-73}$$

where,

AOAM = Annual fixed operating an maintenance costs
IYR = Year
SUMP = Total cumulative patterns initiated
OPSEC_W = Fixed annual operating costs for secondary oil wells
OMO_W = Fixed annual operating costs for crude oil wells
FOAMG_W = Fixed annual operating costs for natural gas wells
OAM_M = Energy elasticity factor for operating and maintenance costs
XPATN = Annual number of active patterns
XPP1 = Number of producing wells drilled per pattern

Variable Operating Costs:

$$OAM_{iyr} = OAM_{iyr} + (OILPROD_{iyr} * OIL\_OAM1 * OAM\_M_{iyr}) + (GASPROD_{iyr} * GAS\_OAM1 * OAM\_M_{iyr}) + (WATPROD_{iyr} * WAT\_OAM1 * OAM\_M_{iyr}) \tag{2-74}$$

$$STIM_{iyr} = STIM_{iyr} + (0.2 * STIM\_W * XPATN_{iyr} * XPP1) \quad (2\text{-}74)$$

For infill drilling: Injectant costs are zero.

$$OAM_{iyr} = OAM_{iyr} + INJ_{iyr} \quad (2\text{-}75)$$

where

OAM	=	Annual variable operating and maintenance costs
OILPROD	=	Annual project level crude oil production
GASPROD	=	Annual project level natural gas production
WATPROD	=	Annual project level water injection
OIL_OAM1	=	Process specific cost of crude oil production ($/Bbl)
GAS_OAM1	=	Process specific cost of natural gas production ($/Mcf)
WAT_OAM1	=	Process specific cost of water production ($/Bbl)
OAM_M	=	Energy elasticity factor for operating and maintenance costs
STIM	=	Project stimulation costs
STIM_W	=	Well stimulation costs
INJ	=	Cost of injection
XPATN	=	Annual number of active patterns
IYR	=	Year
XPP1	=	Number of producing wells drilled per pattern

Cost of Compression (Natural Gas Processes):

Installation costs:

$$COMP_{IYR} = COMP_{IYR} + (COMP\_W*PATN_{IYR}*XPP1) \quad (2\text{-}76)$$

O&M cost for compression:

$$OAM\_COMP_{IYR} = OAM\_COMP_{IYR} + (GASPROD_{IYR} * COMP\_OAM *OAM\_M_{IYR}) \quad (2\text{-}77)$$

where

COMP	=	Cost of installing natural gas compression equipment
COMP_W	=	Natural gas compression cost
PATN	=	Number of patterns initiated each year
IYR	=	Year
XPP1	=	Number of producing wells drilled per pattern
OAM_COMP	=	Operating and maintenance costs for natural gas compression
GASPROD	=	Annual project level natural gas production
COMP_OAM	=	Compressor O & M costs
OAM_M	=	Energy elasticity factor for operating and maintenance costs

Process Dependent Costs

Process-specific facilities and capital costs are calculated at the project level.

Facilities Costs

Profile Model: The facilities cost of a water handling plant is added to the first year facilities costs.

$$FACCOST_1 = FACCOST_1 + PWHP * \left(\frac{RMAX}{365}\right) \quad (2\text{-}78)$$

where

$FACCOST_1$	=	First year of project facilities costs
PWHP	=	Produced water handling plant multiplier
RMAX	=	Maximum annual water injection rate

Polymer Model: The facilities cost for a water handling plant is added to the first year facilities costs.

$$FACCOST_1 = FACCOST_1 + PWP\_F \quad (2\text{-}79)$$

where

$FACCOST_1$	=	First year of project facilities costs
PWP_F	=	Produced water handling plant

Advanced CO_2: Other costs added to the facilities costs include the facilities cost for a CO_2 handling plant and a recycling plant, the O&M cost for a CO_2 handling plant and recycling plant, injectant cost, O&M and fixed O&M costs for a CO_2 handling plant and a recycling plant. If the plant is developed in a single stage, the costs are added to the first year of the facilities costs. If a second stage is required, the additional costs are added to the sixth year of facilities costs.

$$FACCOST1 = FACCOST1 + \left(CO2RK * \left(\frac{0.75 * RMAX}{365}\right)^{CO2RB}\right) * 1{,}000 \quad (2\text{-}80)$$

$$FACCOST6 = FACCOST6 + \left(CO2RK * \left(\frac{0.75 * RMAX}{365}\right)^{CO2RB}\right) * 1{,}000$$

$$INJ_{iyr} = INJ_{iyr} + (TOTINJ_{iyr} - TORECY_{iyr}) * CO2COST \quad (2\text{-}81)$$

$$OAM_{iyr} = OAM_{iyr} + (OAM\_M_{iyr} * TORECY_{iyr}) * (CO2OAM + PSW\_W * 0.25) \quad (2\text{-}82)$$

$$FOAM_{iyr} = (FOAM_{iyr} + TOTINJ_{iyr}) * 0.40 * FCO2 \quad (2\text{-}83)$$

$$TORECY\_CST_{iyr} = TORECY\_CST_{iyr} + (TORECY_{iyr} * CO2OAM2 * OAM\_M_{iyr}) \quad (2\text{-}84)$$

where

IYR	=	Year
RMAX	=	Maximum annual volume of recycled CO_2

CO2OAM	=	O & M cost for CO_2 handling plant
CO2OAM2	=	The O & M cost for the project's CO_2 injection plant
CO2RK, CO2RB	=	CO_2 recycling plant cost coefficients
INJ	=	Cost of purchased CO_2
TOTINJ	=	Annual project level volume of injected CO_2
TORECY	=	Annual project level CO_2 recycled volume
CO2COST	=	Cost of CO_2 ($/mcf)
OAM	=	Annual variable operating and maintenance costs
OAM_M	=	Energy elasticity factor for operating and maintenance costs
FOAM	=	Fixed annual operating and maintenance costs
FCO2	=	Energy elasticity factor for CO_2
FACCOST	=	Annual project facilities costs
TORECY_CST	=	The annual cost of operating the CO_2 recycling plant

Steam Model: Facilities and O&M costs for steam generators and recycling.

Recalculate the facilities costs: Facilities costs include the capital cost for injection plants, which is based upon the OOIP of the project, the steam recycling plant, and the steam generators required for the project.

$$\begin{aligned}\text{FACCOST1} &= \text{FACCOST1} + \left(\frac{OOIP * 0.1 * 2.0 * APAT}{TOTPAT}\right) + (\text{RECY\_WAT} * \text{RMAXWAT} \\ &\quad + \text{RECY\_OIL} * \text{RMAXOIL}) + (\text{STMMA} * \text{TOTPAT} * \text{PATSIZE}) \\ &\quad + (\text{IGEN}_{iyr} - \text{IG}) * \text{STMGA} \qquad (2\text{-}85)\end{aligned}$$

$$\begin{aligned}\text{OAM}_{iyr} &= \text{OAM}_{iyr} + (\text{WAT\_OAM1} * \text{WATPROD}_{iyr} * \text{OAM\_M}_{iyr}) + (\text{OIL\_OAM1} \\ &\quad * \text{OILPROD}_{iyr} * \text{OAM\_M}_{iyr}) + (\text{INJ\_OAM1} * \text{WATINJ}_{iyr} * \text{OAM\_M}_{iyr}) \qquad (2\text{-}86)\end{aligned}$$

where

IYR	=	Year
IGEN	=	Number of active steam generators each year
IG	=	Number of active steam generators in previous year
FACCOST	=	Annual project level facilities costs
RMAXWAT	=	Maximum daily water production rate
RMAXOIL	=	Maximum daily crude oil production rate
APAT	=	Number of developed patterns
TOTPAT	=	Total number of patterns in the project
OOIP	=	Original oil in place (mmbbl)
PATSIZE	=	Pattern size (acres)
STMMA	=	Unit cost for steam manifolds
STMGA	=	Unit cost for steam generators
OAM	=	Annual variable operating and maintenance costs
OAM_M	=	Energy elasticity factor for operating and maintenance costs
WAT_OAM1	=	Process specific cost of water production ($/Bbl)
OIL_OAM1	=	Process specific cost of crude oil production ($/Bbl)

INJ_OAM1	=	Process specific cost of water injection ($/Bbl)
OILPROD	=	Annual project level crude oil production
WATPROD	=	Annual project level water production
WATINJ	=	Annual project level water injection
RECY_WAT	=	Recycling plant cost – water factor
RECY_OIL	=	Recycling plant cost – oil factor

Operating and Maintenance Cost

This subroutine calculates the process specific O&M costs.

Profile Model: Add the O&M costs of injected polymer.

$$INJ_{iyr} = INJ_{iyr} + \frac{OAM\_M_{iyr} * TOTINJ_{iyr} * POLYCOST}{1000} \tag{2-87}$$

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \tag{2-88}$$

where

IYR	=	Year
MAX_YR	=	Maximum number of years
INJ	=	Annual Injection cost
OAM_M	=	Energy elasticity factor for operating and maintenance cost
TOTINJ	=	Annual project level injectant injection volume
POLYCOST	=	Polymer cost
OAM	=	Annual variable operating and maintenance cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Polymer: Add the O&M costs of injected polymer.

$$INJ_{iyr} = INJ_{IYR} + \frac{TOTINJ_{iyr} * POLYCOST}{1,000} \tag{2-89}$$

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \tag{2-90}$$

where

IYR	=	Year
MAX_YR	=	Maximum number of years
INJ	=	Annual Injection cost
TOTINJ	=	Annual project level injectant injection volume
POLYCOST	=	Polymer cost
OAM	=	Annual variable operating and maintenance cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Waterflood: Add the O&M costs of water injected as well as the cost to convert a primary well to an injection well.

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \quad (2\text{-}91)$$

where

IYR	=	Year
MAX_YR	=	Maximum number of years
OAM	=	Annual variable operating and maintenance cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Existing crude oil fields and reservoirs: Since no new drilling or major investments are expected for decline, facilities and drilling costs are zeroed out.

$$OAM_{iyr} = OAM_{iyr} + ((OIL\_OAM1 * OILPROD_{iyr}) + (GAS\_OAM1 * GASPROD_{iyr}) + (WAT\_OAM1 * WATPROD_{iyr})) * OAM\_M_{iyr} \quad (2\text{-}92)$$

$$AOAM_{iyr} = AOAM_{iyr} + \left(\frac{OPSEC\_W * OAM\_M_{iyr} * SUMP_{iyr}}{5} \right) \quad (2\text{-}93)$$

where

IYR	=	Year
OILPROD	=	Annual project level crude oil production
GASPROD	=	Annual project level natural gas production
WATPROD	=	Annual project level water production
OIL_OAM1	=	Process specific cost of crude oil production ($/Bbl)
GAS_OAM1	=	Process specific cost of natural gas production ($/Mcf)
WAT_OAM1	=	Process specific cost of water production ($/Bbl)
OAM_M	=	Energy elasticity factor for operating and maintenance costs
OPSEC_W	=	Fixed annual operating cost for secondary well operations
SUMP	=	Cumulative patterns developed
AOAM	=	Fixed annual operating and maintenance costs
OAM	=	Variable annual operating and maintenance costs

Overhead Costs: : General and Administrative (G&A) costs on capitalized and expensed items, which consist of administration, accounting, contracting and legal fees/expenses for the project, are calculated according to the following equations:

$$GNA\_EXP_{itech} = GNA\_EXP_{itech} * CHG\_GNA\_FAC_{itech} \quad (2\text{-}94)$$
$$GNA\_CAP_{itech} = GNA\_CAP_{itech} * CHG\_GNA\_FAC_{itech} \quad (2\text{-}95)$$

where

ITECH	=	Technology case (base and advanced) number
GNA_EXP	=	The G&A rate applied to expensed items for the project
GNA_CAP	=	The G&A rate applied to capitalized items for the project
CHG_GNA_FAC	=	Technology case specific change in G&A rates

Timing

Overview of Timing Module

The timing routine determines which of the exploration and EOR/ASR projects are eligible for development in any particular year. Those that are eligible are subject to an economic analysis and passed to the project sort and development routines. The timing routine has two sections. The first applies to exploration projects while the second is applied to EOR/ASR and developing natural gas projects.

Figure 2-9 provides the overall logic for the exploration component of the timing routine. For each project regional crude oil and natural gas prices are obtained. The project is then examined to see if it has previously been timed and developed. The timed projects are no longer available and thus not considered.

The model uses four resource access categories for the undiscovered projects:

- No leasing due to statutory or executive order
- Leasing available but cumulative timing limitations between 3 and 9 months
- Leasing available but with controlled surface use
- Standard leasing terms

Each project has been assigned to a resource access category. If the access category is not available in the year evaluated, the project fails the resource access check.

After the project is evaluated, the number of considered projects is increased. Figure 2-10 shows the timing logic applied to the EOR/ASR projects as well as the developing natural gas projects.

Before the economics are evaluated, the prices are set and the eligibility is determined. The following conditions must be met:

- Project has not been previously timed
- Project must be eligible for timing, re-passed the economic pre-screening routine
- Corresponding decline curve project must have been timed. This does not apply to the developing natural gas projects.

If the project meets all of these criteria, then it is considered eligible for economic analysis. For an EOR/ASR project to be considered for timing, it must be within a process specific EOR/ASR development window. These windows are listed in Table 2-4.

Table 2-4: EOR/ASR Eligibility Ranges

Process	Before Economic Limit	After Economic Limit
CO_2 Flooding	After 2009	10 Years
Steam Flooding	5 Years	10 Years
Polymer Flooding	5 Years	10 Years
Infill Drilling	After 2009	7 Years
Profile Modification	5 Years	7 Years
Horizontal Continuity	5 Years	7 Years
Horizontal Profile	5 Years	7 Years
Waterflood	4 Years	6 Years

The economic viability of the eligible projects is then evaluated. A different analytical approach is applied to CO_2 EOR and all other projects. For non-CO_2 EOR projects the project is screened for applicable technology levers, and the economic analysis is conducted. CO_2 EOR projects are treated differently because of the different CO_2 costs associated with the different sources of industrial and natural CO_2.

For each available source, the economic variables are calculated and stored. These include the source of CO_2 and the project's ranking criterion.

Detailed description of timing module

Exploration projects: The first step in the timing module is to determine which reservoirs are eligible to be timed for conventional and continuous exploration. Prior to evaluation, the constraints, resource access, and technology and economic levers are checked, and the technology case is set.

Calculate economics for EOR/ASR and developing natural gas projects:
This section determines whether an EOR/ASR or developing natural gas project is eligible for economic analysis and timing. The following resources are processes considered in this step.
EOR Processes:

- CO_2 Flooding
- Steam Flooding
- Polymer Flooding
- Profile Modification

ASR Processes:

- Water Flooding
- Infill Drilling
- Horizontal Continuity
- Horizontal Profile

Developing natural gas

- Tight Gas
- Shale Gas
- Coalbed Methane

A project is eligible for timing if the corresponding decline curve project has previously been timed and the year of evaluation is within the eligibility window for the process, as listed in table 2-4.

Project Ranking: Sorts exploration and EOR/ASR projects which are economic for timing. The subroutine matches the discovery order for undiscovered projects and sorts the others by ranking criterion. The criteria include

- Net present value
- Investment efficiency
- Rate of return
- Cumulative discounted after tax cashflow

Selection and Timing: Times the exploration and EOR/ASR projects which are considered in that given year.

Project Selection

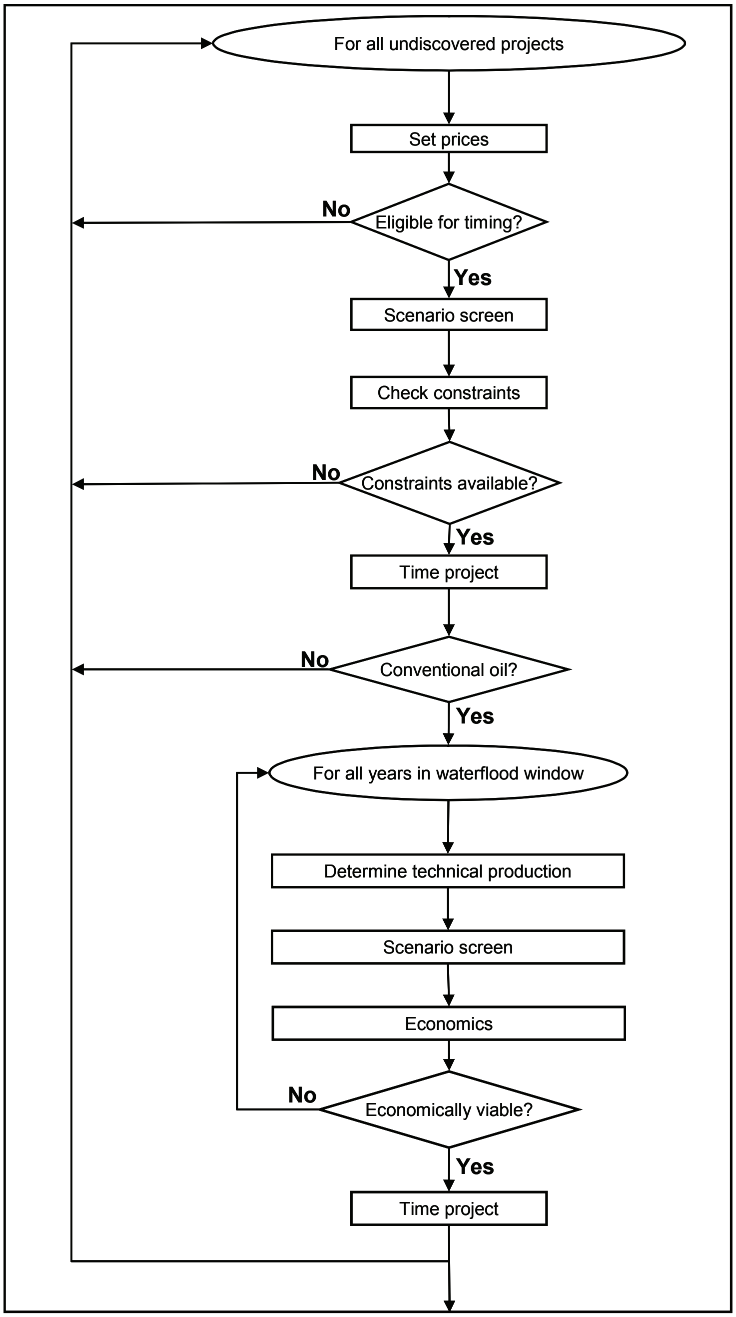
The project selection subroutine determines which exploration, EOR/ASR and developing natural gas projects will be modeled as developed in each year analyzed. In addition, the following development decisions are made:

- Waterflood of conventional undiscovered crude oil projects
- Extension of CO_2 floods as the total CO_2 injected is increased from 0.4 hydrocarbon pore volume (HCPV) to 1.0 HCPV

Overview of Project Selection

The project selection subroutine evaluates undiscovered projects separate from other projects. The logic for the development of exploration projects is provided in figure 2-9.

Figure 2-9: Selecting Undiscovered Projects



As illustrated in the figure the prices are set for the project before its eligibility is checked. Eligibility has the following requirements:

- Project is economically viable
- Project is not previously timed and developed

The projects which are eligible are screened for applicable technologies which impact the drilling success rates. The development constraints required for the project are checked against those that are available in the region.

If sufficient development resources are available, the project is timed and developed. As part of this process, the available development constraints are adjusted, the number of available accumulations is reduced and the results are aggregated. If no undiscovered accumulations remain, then the project is no longer eligible for timing. The projects that are eligible, economically viable, and undeveloped due to lack of development resources, are considered again for future projection years. If the project is conventional crude oil, it is possible to time a waterflood project.

The model evaluates the waterflood potential in a window centered upon the end of the economic life for the undiscovered project. For each year of that window, the technical production is determined for the waterflood project, applicable technology and economic levers are applied, and the economics are considered. If the waterflood project is economic, it is timed. This process is continued until either a waterflood project is timed or the window closes.

The second component of the project selection subroutine is applicable to EOR/ASR projects as well as the developing natural gas projects. The major steps applied to these projects are detailed in figures 2-10 and 2-11.

As seen in the flowchart, the prices are set for the project and the eligibility is checked. As with the undiscovered projects, the subroutine checks the candidate project for both economic viability and eligibility for timing. Afterwards, the project is screened for any applicable technology and economic levers.

If the project is eligible for CO_2 EOR, the economics are re-run for the specific source of CO_2. Afterwards, the availability of resource development constraints is checked for the project. If sufficient drilling and capital resources are available, the project preferences are checked.

The project preferences are rules which govern the competition between projects and selection of projects; these rules are listed below:

- CO_2 EOR and infill drilling are available after 2010
- Profile modification becomes available after 2011
- The annual number of infill drilling and profile modification projects is limited
- Horizontal continuity can compete against any other process except steam flood
- Horizontal profile can compete against any other process except steam flood or profile modification
- Polymer flooding cannot compete against any other process

If the project meets the technology preferences, then it is timed and developed. This process is different for CO_2 EOR and all other processes.

Figure 2-10: Selecting EOR/ASR projects

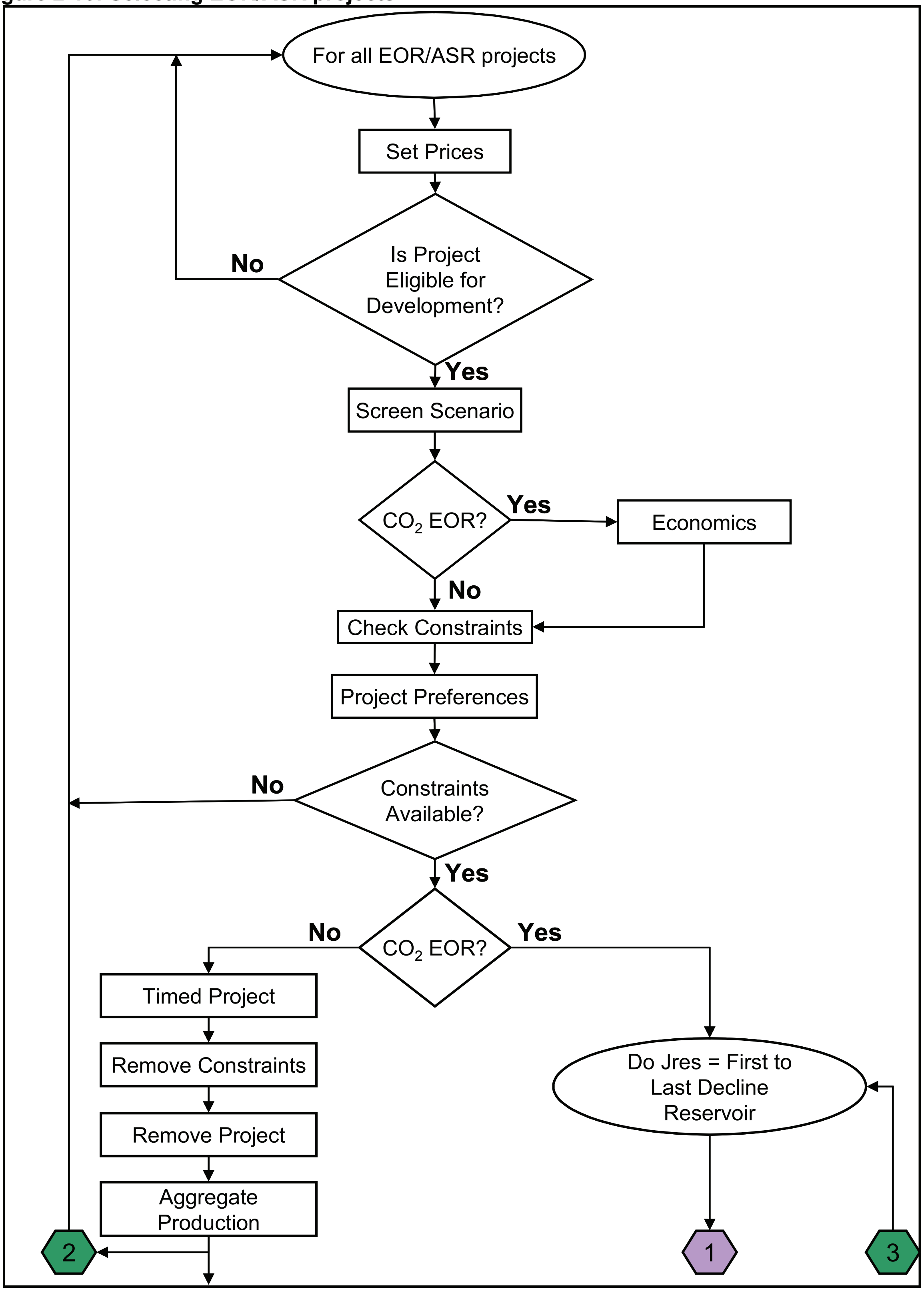
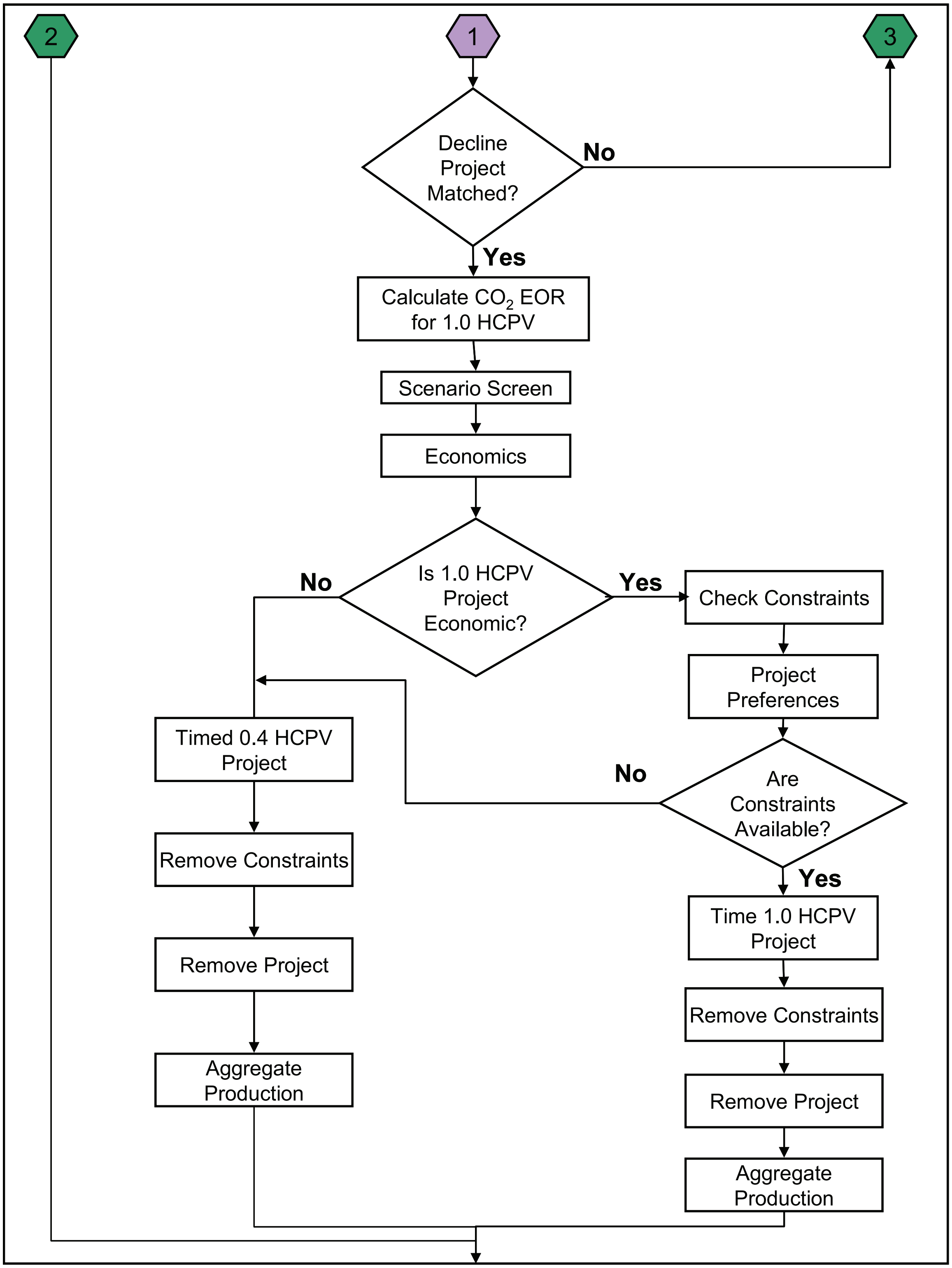


Figure 2-11: Selecting EOR/ASR projects, Continued



For non-CO_2 projects, the constraints are adjusted, the project is removed from the list of eligible projects, and the results are aggregated. It is assumed that most EOR/ASR processes are mutually exclusive and that a reservoir is limited to one process. There are a few exceptions:

- CO_2 EOR and infill drilling can be done in the same reservoir
- CO_2 EOR and horizontal continuity can be done in the same reservoir

For CO_2 EOR projects, a different methodology is used at this step: the decision to increase the total CO_2 injection from 0.4 hydrocarbon pore volume (HCPV) to 1.0 HCPV is made. The model performs the following steps, illustrated in figure 2-10 and continued in figure 2-11.

The CO_2 EOR project is matched to the corresponding decline curve project. Using the project-specific petro-physical properties, the technical production and injection requirements are determined for the 1.0 HCPV project. After applying any applicable technology and economic levers, the model evaluates the project economics. If the 1.0 HCPV project is not economically viable, then the 0.4 HCPV project is timed. If the 1.0 HCPV project is viable, the constraints and project preferences are checked. Assuming that there are sufficient development resources, and competition allows for the development of the project, then the model times the 1.0 HCPV project. If sufficient resources for the 1.0 HCPV project are not available, the model times the 0.4 HCPV project.

Detailed description of project selection

The project selection subroutine analyzes undiscovered crude oil and natural gas projects. If a project is economic and eligible for development, the drilling and capital constraints are examined to determine whether the constraints have been met. The model assumes that the projects for which development resources are available are developed.

Waterflood processing may be considered for undiscovered conventional crude oil projects. The waterflood project will be developed in the first year it is both eligible for implementation and the waterflood project is economically viable.

EOR/ASR Projects

When considering whether a project is eligible for EOR/ASR processing, the model first checks the availability of sufficient development resources are available. Based on the project economics and projected availability of development resources, it also decides whether or not to extend injection in CO_2 EOR projects from 0.4 HCPV to 1.0 HCPV.

If the 1.0 HCPV is economic but insufficient resources are available, the 0.4 HCPV project is selected instead. If the 1.0 HCPV project is uneconomic, the 0.4 HCPV project is selected.

Constraints

Resource development constraints are used during the selection of projects for development in order to mimic the infrastructure limitations of the oil and gas industry. The model assumes that only the projects that do not exceed the constraints available will be developed.

Types of constraints modeled

The development constraints represented in the model include drilling footage availability, rig depth rating, capital constraints, demand for natural gas, carbon dioxide volumes, and resource access.

In the remainder of this section, additional details will be provided for each of these constraints.

Drilling: Drilling constraints are bounding values used to determine the resource production in a given region. OLOGSS uses the following drilling categories:

- Developmental crude oil – applied to EOR/ASR projects
- Developmental natural gas – applied to developing natural gas projects
- Horizontal drilling – applied to horizontal wells
- Dual use – available for either crude oil or natural gas projects
- Conventional crude oil exploration – applied to undiscovered conventional crude oil projects
- Conventional natural gas exploration – applied to undiscovered conventional natural gas projects
- Continuous crude oil exploration – applied to undiscovered continuous crude oil projects
- Continuous natural gas exploration – applied to undiscovered continuous natural gas projects

Except for horizontal drilling, which is calculated as a fraction of the national developmental crude oil footage, all categories are calculated at the national level and apportioned to the regional level. Horizontal drilling is at the national level.

The following equations are used to calculate the national crude oil development drilling. The annual footage available is a function of lagged five year average crude oil prices and the total growth in drilling.

The total growth in drilling is calculated using the following algorithm.
<u>For the first year:</u>

$$\mathrm{TOT\_GROWTH} = 1.0 * \left(1.0 + \frac{\mathrm{DRILL\_OVER}}{100}\right) \tag{2-96}$$

<u>For the remaining years:</u> (2-97)

$$\mathrm{TOT\_GROWTH} = \left(\left(\mathrm{TOT\_GROWTH} * \left(1.0 + \frac{\mathrm{RGR}}{100}\right)\right) - \left(\mathrm{TOT\_GROWTH} * \left(1.0 + \frac{\mathrm{RGR}}{100}\right)\right) * \left(\frac{\mathrm{RRR}}{100}\right)\right) * \left(1.0 * \frac{\mathrm{DRILL\_OVER}}{100}\right)$$

Reviewers note: The equation above would be clearer if it were written as

where

IYR	=	Year evaluated
MAX_YR	=	Maximum number of years
TOT_GROWTH	=	Annual growth change for drilling at the national level (fraction)
DRILL_OVER	=	Percent of drilling constraint available for footage over run
RGR	=	Annual rig development rate (percent)
RRR	=	Annual rig retirement rate (percent)

The national level crude oil and natural gas development footage available for drilling is calculated using the following equations. The coefficients for the drilling footage equations were estimated by least squares using model equations 2.B-16 and 2.B-17 in Appendix 2.B.

$$NAT\_OIL_{IYR} = (OILA0 + OILA1 * OILPRICED_{IYR}) * TOTMUL * TOT\_GROWTH * OIL\_ADJ_{IYR} \quad (2\text{-}98)$$

$$NAT\_GAS_{IYR} = (GASA0 + GASA1 * GASPRICED_{IYR}) * TOTMUL * TOT\_GROWTH * GAS\_ADJ_{IYR} \quad (2\text{-}99)$$

where

IYR	=	Year evaluated
TOT_GROWTH	=	Final calculated annual growth change for drilling at the national level
NAT_OIL NAT_GAS	=	National development footage available (Thousand Feet)
OILA0,1 GASA0,1	=	Footage equation coefficients
OILPRICED GASPRICED	=	Annual prices used in drilling constraints, five year average
TOTMUL	=	Total drilling constraint multiplier
OIL_ADJ GAS_ADJ	=	Annual crude oil, natural gas developmental drilling availability factors

After the available footage for drilling is calculated at the national level, regional allocations are used to allocate the drilling to each of the OLOGSS regions. The drilling which is not allocated, due to the “drill_trans” factor, is available in any region and represents the drilling which can be transferred among regions. The regional allocations are then subtracted from the national availability.

$$REG\_OIL_{j,iyr} = NAT\_OIL_{IYR} * \left(\frac{PRO\_REGOIL_J}{100}\right) * \left(1.0 - \frac{DRILL\_TRANS}{100}\right) \quad (2\text{-}100)$$

where

J	=	Region number
IYR	=	Year

REG_OIL	=	Regional development oil footage (Thousand Feet) available in a specified region
NAT_OIL	=	National development oil footage (Thousand Feet). After allocation, the footage transferrable among regions.
PRO_REGOIL	=	Regional development oil footage allocation (percent)
DRILL_TRANS	=	Percent of footage that is transferable among regions

Footage Constraints: The model determines whether there is sufficient footage available to drill the complete project. The drilling constraint is applied to all projects. Footage requirements are calculated in two stages: vertical drilling and horizontal drilling. The first well for an exploration project is assumed to be a wildcat well and uses a different success rate than the other wells in the project. The vertical drilling is calculated using the following formula.

For non-exploration projects:

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEKD_{itech})) * PATDEV_{irs,ii-itimeyr+1,itech} * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (DEPTH_{itech} * PATDEV_{irs,ii-itiimeyr+1,itech}) * 0.5 * ATOTCONV_{irs,itech} \quad (2\text{-}101)$$

For exploration projects:

For the first year of the project (2-102)

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEUE_{itech})) * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (0.5 * ATOTCONV_{irs,itech}) + (DEPTH_{itech} * (1.0 + SUC\_RATEUD_{itech})) * (PATDEV_{irs,ii-itimeyr+1,itech} - 1 * ATOTPROD_{irs,itech} + ATOTINJ_{ir,itech} + 0.5 * ATOTCONV_{irs,itech})$$

For all other project years (2-103)

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEUD_{itech})) * PATDEV_{irs,ii-itimeyr+1,itech} * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (DEPTH_{itech} * PATDEV_{irs,ii-itimeyr+1,itech} * 0.5 * ATOTCONV_{irs,itech})$$

where

irs	=	Project index number
itech	=	Technology index number
itimeyr	=	Year in which project is evaluated for development
ii	=	Year evaluated
FOOTREQ	=	Footage required for drilling (Thousand Feet)
DEPTH	=	Depth of formation (Feet)
SUC_RATEKD	=	Success rate for known development
SUC_RATEUE	=	Success rate for undiscovered exploration (wildcat)
SUC_RATEUD	=	Success rate for undiscovered development
PATDEV	=	Annual number of patterns developed for base and advanced technology
ATOTPROD	=	Number of new producers drilled per pattern
ATOTINJ	=	Number of new injectors drilled per patterns
ATOTCONV	=	Number of conversions from producing to injection wells per pattern

Add Laterals and Horizontal Wells: The lateral length and the horizontal well length are added to the footage required for drilling.

$$FOOTREQii = FOOTREQii + (ALATNUM_{irs,itech} * ALATLEN_{irs,itech} * (1.0 + SUC\_RATEKD_{itech}) * PATDEV_{irs,ii-itimeyr+1,itech}) \quad (2\text{-}104)$$

where

irs	=	Project index number
itech	=	Technology index number
itimeyr	=	Year in which project is evaluated for development
ii	=	Year evaluated
FOOTREQ	=	Footage required for drilling (Feet)
ALATNUM	=	Number of laterals
ALATLEN	=	Length of laterals (Feet)
SUC_RATEKD	=	Success rate for known development
PATDEV	=	Annual number of patterns developed for base and advanced technology

After determining the footage requirements, the model calculates the footage available for the project. The available footage is specific to the resource, the process, and the constraint options which have been specified by the user. If the footage required to drill the project is greater than the footage available then the project is not feasible.

Rig depth rating: The rig depth rating is used to determine whether a rig is available which can drill to the depth required by the project. OLOGSS uses the nine rig depth categories provided in table 2-5.

Table 2-5 Rig Depth Categories

Depth Category	Minimum Depth (Ft)	Maximum Depth (Ft)
1	1	2,500
2	2,501	5,000
3	5,001	7,500
4	7,501	10,000
5	10,001	12,500
6	12,501	15,000
7	15,001	17,500
8	17,251	20,000
9	20,001	Deeper

The rig depth rating is applied at the national level. The available footage is calculated using the following equation.

$$RDR\_FOOTAGE_{j,\, iyr} = (NAT\_TOT_{iyr} + NAT\_EXP_{iyr} + NAT\_EXPG_{iyr}) * \frac{RDR_j}{100} \quad (2\text{-}106)$$

where

J	=	Rig depth rating category
IYR	=	Year
RDR_FOOTAGE	=	Footage available in this interval (K Ft)

NAT_TOT = Total national developmental (crude oil, natural gas, and horizontal)
drilling footage available (Thousand feet)

NAT_EXPG = National gas exploration drilling constraint

NAT_EXP = Total national exploration drilling footage available (Thousand feet)

RDR_j = Percentage of rigs which can drill to depth category j

Capital: Crude oil and natural gas companies use different investment and project evaluation criteria based upon their specific cost of capital, the portfolio of investment opportunities available, and their perceived technical risks. OLOGSS uses capital constraints to mimic limitations on the amount of investments the oil and gas industry can make in a given year. The capital constraint is applied at the national level.

Natural Gas Demand: Demand for natural gas is calculated at the regional level by the NGTDM and supplied to OLOGSS.

Carbon Dioxide: For CO_2 miscible flooding, availability of CO_2 gas from natural and industrial sources is a limiting factor in developing the candidate projects. In the Permian Basin, where the majority of the current CO_2 projects are located, the CO_2 pipeline capacity is a major concern.

The CO_2 constraint in OLOGSS incorporates both industrial and natural sources of CO_2. The industrial sources of CO_2 are ammonia plants, hydrogen plants, existing and planned ethanol plants, cement plants, refineries, fossil fuel power plants, and new IGCC plants.

Technology and market constraints prevent the total volumes of CO_2 produced from becoming immediately available. The development of the CO_2 market is divided into 3 periods:
1) technology R&D, 2) infrastructure construction, and 3) market acceptance. The capture technology is under development during the R&D phase, and no CO_2 produced by the technology is assumed available at that time. During the infrastructure development, the required capture equipment, pipelines, and compressors are being constructed, and no CO_2 is assumed available. During the market acceptance phase, the capture technology is being widely implemented and volumes of CO_2 are assumed to become available.

The maximum CO_2 available is achieved when the maximum percentage of the industry that will adopt the technology has adopted it. This provides an upper limit on the volume of CO_2 that will be available. The graph below provides the annual availability of CO_2 from ammonia plants. Availability curves were developed for each source of industrial, as well as natural CO_2.

CO_2 constraints are calculated at the regional level and are source specific.

Resource Access: Restrictions on access to Federal lands constrain the development of undiscovered crude oil and natural gas resources. OLOGSS uses four resource access categories:

- No leasing due to statutory or executive order
- Leasing available but cumulative timing limitations between 3 and 9 months
- Leasing available but with controlled surface use
- Standard leasing terms

The percentage of the undiscovered resource in each category was estimated using data from the Department of Interior's Basin Inventories of Onshore Federal Land's Oil and Gas Resources.

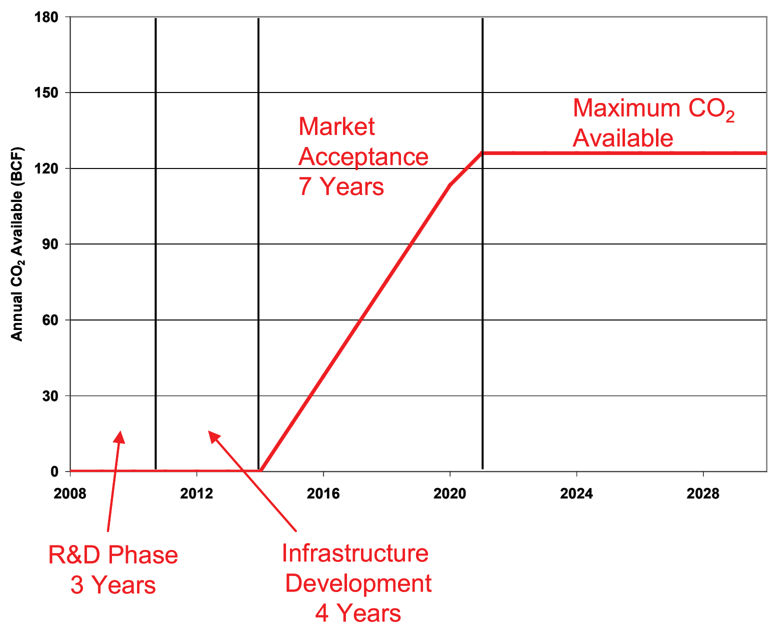


Figure 2-12: CO2 Market Acceptance Curve

Technology

Research and development programs are designed to improve technology to increase the amount of resources recovered from crude oil and natural gas fields. Key areas of study include methods of increasing production, extending reserves, and reducing costs. To optimize the impact of R & D efforts, potential benefits of a new technology are weighed against the costs of research and development. OLOGSS has the capability to model the effects of R & D programs and other technology improvements as they impact the production and economics of a project. This is done in two steps: (1) modeling the implementation of the technology within the oil and gas industry and (2) modeling the costs and benefits for a project that applies this technology.

Impact of technology on economics and recovery

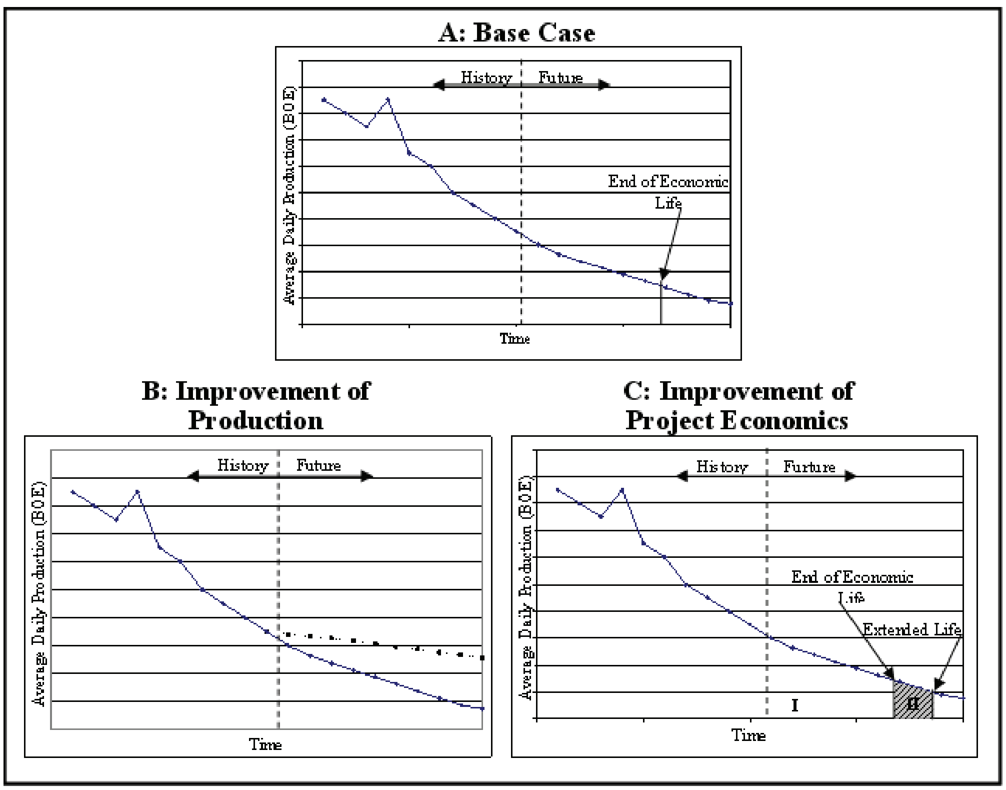
Figure 2-13 illustrates the effects of technology improvement on the production and project economics of a hypothetical well. The graphs plot the daily average production, projected by decline analysis, over the life of the project. Each graph represents a different scenario: (A) base case, (B) production improvement, and (C) economic improvement.

Graph A plots the production for the base case. In the base case, no new technology is applied to the project. The end of the project's economic life, the point at which potential revenues are less than costs of further production, is indicated. At that point, the project would be subject to reserves-growth processes or shut in.

Graph B plots the production for the base case and a production-increasing technology such as skin reduction. The reduction in skin, through well-bore fracturing or acidizing, increases the daily production flow rate. The increase in daily production rate is shown by the dotted line in graph B. The outcome of the production-increasing technology is reserves growth for the well. The amount of reserves growth for the well is shown by the area between the two lines as illustrated in figure 2-13 graph B.

Another example of technology improvement is captured in graph C. In this case a technology is implemented that reduces the cost of operation and maintenance, thereby extending the reservoir life as shown in figure 2-13 graph C.

Figure 2-13: Impact of Economic and Technology Levers

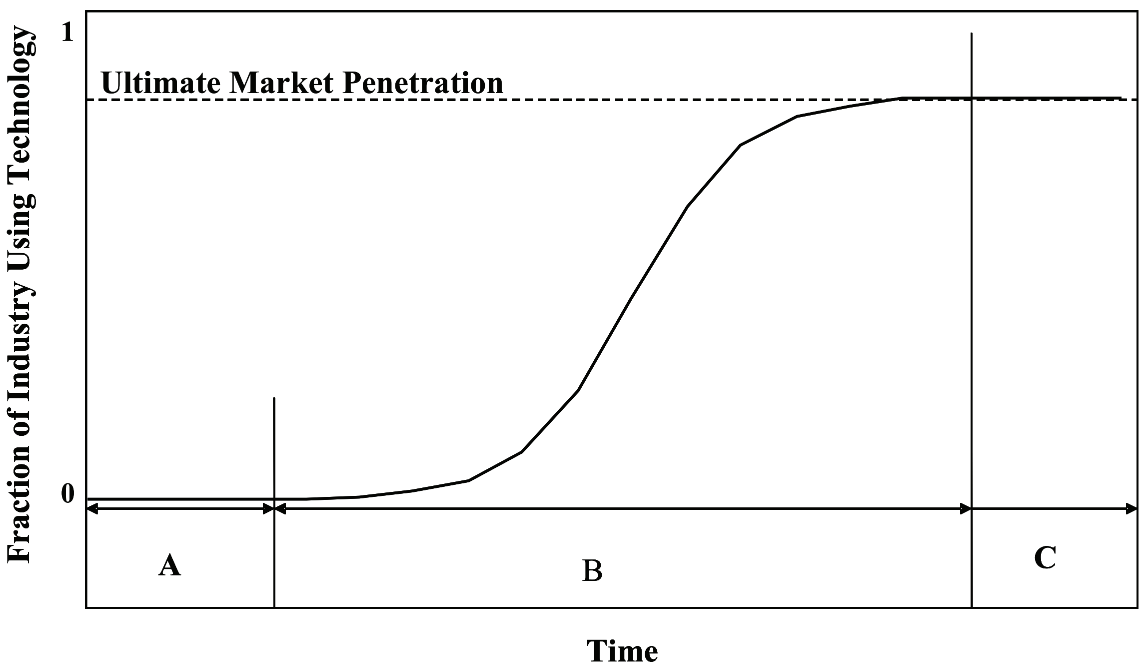


Technology improvements are modeled in OLOGSS using a variety of technology and economic levers. The technology levers, which impact production, are applied to the technical production of the project. The economic levers, which model improvement in project economics, are applied to cashflow calculations. Technology penetration curves are used to model the market penetration of each technology.

The technology-penetration curve is divided into three sections, each of which represents a phase of development. The first section is the research and development phase. In this phase the technology is developed and tested in the laboratory. During these years, the industry may be aware of the technology but has not begun implementation, and therefore does not see a benefit to production or economics. The second section corresponds to the commercialization phase. In the commercialization phase, the technology has successfully left the laboratory and is being adopted by the industry. The third section represents maximum market penetration. This is the ultimate extent to which the technology is adopted by the industry.

Figure 2-14 provides the graph of a generic technology-penetration curve. This graph plots the fraction of industry using the new technology (between 0 and 1) over time. During the research and development phase (A) the fraction of the industry using the technology is 0. This increases during commercialization phase (B) until it reaches the ultimate market penetration. In phase C, the period of maximum market acceptance, the percentage of industry using the technology remains constant.

Figure 2-14: Generic Technology Penetration Curve

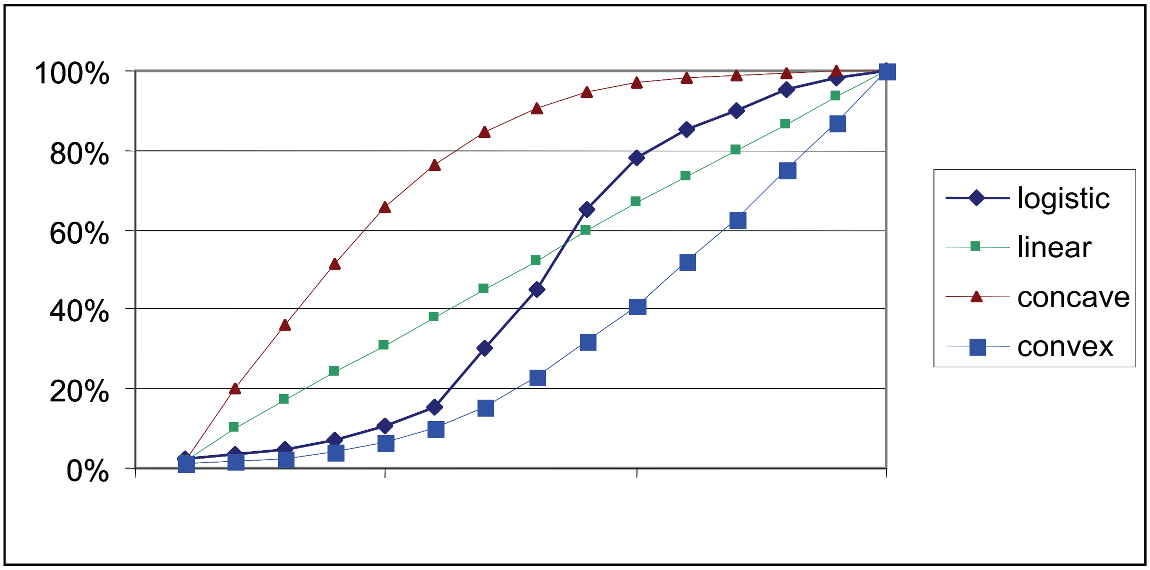


Technology modeling in OLOGSS

The success of the technology program is measured by estimating the probability that the technology development program will be successfully completed. It reflects the pace at which technology performance improves and the probability that the technology project will meet the program goals. There are four possible curve shapes that may represent the adoption of the technology: convex, concave, sigmoid/logistic or linear, as shown in figure 2-15. The convex curve corresponds to rapid initial market penetration followed by slow market penetration. The concave curve corresponds to slow initial market penetration followed by rapid market penetration. The sigmoid/logistic curve represents a slow initial adoption rate followed by rapid increase in adoption and the slow adoption again as the market becomes saturated. The linear curve represents a constant rate of market penetration, and may be used when no other predictions can be made.

The market penetration curve is a function of the relative economic attractiveness of the technology instead of being a time-dependent function. A technology will not be implemented unless the benefits through increased production or cost reductions are greater than the cost to apply the technology. As a result, the market penetration curve provides a limiting value on commercialization instead of a specific penetration path. In addition to the curve, the implementation probability captures the fact that not all technologies that have been proved in the lab are able to be successfully implemented in the field. The implementation probability does not reflect resource access, development constraints, or economic factors.

Figure 2-15: Potential Market Penetration Profiles



The three phases of the technology penetration curve are modeled using three sets of equations. The first set of equations models the research and development phase, the second set models the commercialization phase, and the third set models the maximum market penetration phase.

In summary, technology penetration curves are defined using the following variables:

- Number of years required to develop a technology = Y_d
- First year of commercialization = Y_c
- Number of years to fully penetrate the market = Y_a
- Ultimate market penetration (%) = UP
- Probability of success = P_s
- Probability of implementation = P_i
- Percent of industry implementing the technology (fraction) in year x = Imp_x

Research and Development Phase:
During the research and development phase, the percentage of industry implementing the new technology for a given year is zero.

This equation is used for all values of *market_penetration_profile.*

Commercialization Phase:

The commercialization phase covers the years from the beginning of commercialization through the number of years required to fully develop the technology. The equations used to model this phase depend upon the value of *market_penetration_profile.*

If the *market_penetration_profile* is assumed to be *convex*, then

Step 1: Calculate raw implementation percentage:

$$Imp_{xr} = -0.9 * 0.4^{[(x - Ys) / Ya]} \tag{2-105}$$

Step 2: Normalize Imp_x using the following equation:

$$Imp_x = \frac{[(-0.6523) - Imp_x]}{[(-0.6523) - (-0.036)]} \tag{2-106}$$

If the *market_penetration_profile* is assumed to be *concave*, then

Step 1: Calculate raw implementation percentage:

$$Imp_x = 0.9 * 0.04^{[1 - \{(x + 1 - Ys)/ Ya\}]} \tag{2-107}$$

Step 2: Normalize Imp_x using the following equation:

$$Imp_x = \frac{[(0.04) - Imp_{xr}]}{[(0.04) - (0.74678)]} \tag{2-108}$$

If the *market_penetration_profile* is assumed to be *sigmoid*, then

Step 1: Determine midpoint of the sigmoid curve = int $\left(\frac{Y_a}{2}\right)$

Where int$\left(\frac{Y_a}{2}\right) = \left(\frac{Y_a}{2}\right)$ rounded to the nearest integer

Step 2: Assign a value of 0 to the midpoint year of the commercialization period, incrementally increase the values for the years above the midpoint year, and incrementally decrease the values for the years below the midpoint year.

Step 3: Calculate raw implementation percentage:

$$Imp_x = \frac{e^{value_x}}{1 + e^{value_x}} \tag{2-109}$$

No normalizing of Imp_x is required for the sigmoid profile.

If the *market_penetration_profile* is assumed to be *linear*, then

Step 1: Calculate the raw implementation percentage:

$$\text{Imp}_x = \left[\frac{P_s * P_i * UP}{Y_a + 1}\right] * x_i \qquad (2\text{-}110)$$

No normalizing of Imp_x is required for the linear profile.

Note that the maximum technology penetration is 1.

Ultimate Market Penetration Phase:
For each of the curves generated, the ultimate technology penetration applied per year will be calculated using:

$$\text{Imp}_{final} = \text{Imp}_x * P_s * P_i \qquad (2\text{-}111)$$

Note that Imp_{final} is not to exceed Ultimate Market Penetration ("UP")

Using these three sets of equations, the industry-wide implementation of a technology improvement can be mapped using a technology-penetration curve.

Levers included in model

Project Level Technology Impact: Adopting a new technology can impact two aspects of a project. It improves the production and/or improves the economics. Technology and economic levers are variables in OLOGSS. The values for these levers are set by the user.

There are two cost variables to which economic levers can be applied in the cashflow calculations: the cost of applying the technology and the cost reductions that result from the technology's implementation. The cost to apply is the incremental cost to apply the technology. The cost reduction is the savings associated with using the new technology. The "cost to apply" levers can be applied at the well and/or project level. The model recognizes the distinction between technologies that are applied at the well level – modeling while drilling - and reservoir characterization and simulation, which affects the entire project. By using both types of levers, users can model the relationship between implementation costs and offsetting cost reductions.

The model assumes that the technology will be implemented only if the cost to apply the technology is less than the increased revenue generated through improved production and cost reductions.

Resource and Filter Levers: Two other types of levers are incorporated into OLOGSS: resource-access levers and technology levers. Resource-access levers allow the user to model changes in resource-access policy. For example, the user can specify that the federal lands in the Santa Maria Basin, which are currently inaccessible due to statutory or executive orders, will be available for exploration in 2015. A series of filter levers is also incorporated in the model. These are used to specifically locate the impact of technology improvement. For example, a technology can be applied only to CO_2 flooding projects in the Rocky Mountain region that are between 5,000 and 7,000 feet deep.

Appendix 2.A: Onshore Lower 48 Data Inventory

Variable Name	Variable Type	Description	Unit
AAPI	Input	API gravity	
AARP	Input	CO_2 source acceptance rate	
ABO	Variable	Current formation volume factor	Bbl/stb
ABOI	Input	Initial formation volume factor	Bbl/stb
ABTU	Variable	BTU content	Btu/Cf
ACER	Input	ACE rate	Percent
ACHGASPROD	Input	Cumulative historical natural gas production	MMcf
ACHOILPROD	Input	Cumulative historical crude oil production	MBbl
ACO2CONT	Input	CO_2 impurity content	%
ADEPTH	Input	Depth	Feet
ADGGLA	Variable	Depletable items in the year (G & G and lease acquisition cost)	K$
ADJGAS	Variable	National natural gas drilling adjustment factor	Fraction
ADJGROSS	Variable	Adjusted gross revenue	K$
ADJOIL	Variable	National crude oil drilling adjustment factor	Fraction
ADOILPRICE	Variable	Adjusted crude oil price	$/Bbl
ADVANCED	Variable	Patterns to be developed using advanced technology	Fraction
AECON_LIFE	Variable	Economic life of the project	Years
AFLP	Input	Portion of reservoir on federal lands	Fraction
AGAS_GRAV	Input	Natural gas gravity	
AGOR	Input	Gas/oil ratio	Mcf/bbl
AH2SCONT	Input	H_2S impurity content	%
AHCPV	Variable	Hydro Carbon Pore Volume	0.4 HCPV
AHEATVAL	Input	Heat content of natural gas	Btu/Cf
AINJINJ	Input	Annual injectant injected	MBbl, Mcf, MLbs
AINJRECY	Variable	Annual injectant recycled	MBbl, Mcf
AIRSVGAS	Variable	End of year inferred natural gas reserves	MMcf
AIRSVOIL	Variable	End of year inferred crude oil reserves	MBbl
ALATLEN	Input	Lateral length	Feet
ALATNUM	Input	Number of laterals	
ALYRGAS	Input	Last year of historical natural gas production	MMcf

ALYROIL	Input	Last year of historical crude oil production	MBbl
AMINT	Variable	Alternative minimum income tax	K$
AMOR	Variable	Intangible investment depreciation amount	K$
AMOR_BASE	Variable	Amortization base	K$
AMORSCHL	Input	Annual fraction amortized	Fraction
AMT	Input	Alternative minimum tax	K$
AMTRATE	Input	Alternative minimum tax rate	K$
AN2CONT	Input	N_2 impurity content	%
ANGL	Input	NGL	bbl/MMcf
ANUMACC	Input	Number of accumulations	
ANWELLGAS	Input	Number of natural gas wells	
ANWELLINJ	Input	Number of injection wells	
ANWELLOIL	Input	Number of crude oil wells	
AOAM	Variable	Annual fixed O & M cost	K$
AOGIP	Variable	Original Gas in Place	Bcf
AOILVIS	Input	Crude Oil viscosity	CP
AOOIP	Variable	Original Oil In Place	MBbl
AORGOOIP	Input	Original OOIP	MBbl
APATSIZ	Input	Pattern size	Acres
APAY	Input	Net pay	Feet
APD	Variable	Annual percent depletion	K$
APERM	Input	Permeability	MD
APHI	Input	Porosity	Percent
APLAY_CDE	Input	Play number	
APRESIN	Variable	Initial pressure	PSIA
APRODCO2	Input	Annual CO_2 production	MMcf
APRODGAS	Input	Annual natural gas production	MMcf
APRODNGL	Input	Annual NGL production	MBbl
APRODOIL	Input	Annual crude oil production	MBbl
APRODWAT	Input	Annual water production	MBbl
APROV	Input	Province	
AREGION	Input	Region number	
ARESACC	Input	Resource Access	
ARESFLAG	Input	Resource flag	
ARESID	Input	Reservoir ID number	
ARESVGAS	Variable	End of year proven natural gas reserves	MMcf
ARESVOIL	Variable	End of year proven crude oil reserves	MBbl
ARRC	Input	Railroad Commission District	
ASC	Input	Reservoir Size Class	
ASGI	Variable	Gas saturation	Percent
ASOC	Input	Current oil saturation	Percent
ASOI	Input	Initial oil saturation	Percent

ASOR	Input	Residual oil saturation	Percent
ASR_ED	Input	Number of years after economic life of ASR	
ASR_ST	Input	Number of years before economic life of ASR	
ASULFOIL	Input	Sulfur content of crude oil	%
ASWI	Input	Initial water saturation	Percent
ATCF	Variable	After tax cashflow	K$
ATEMP	Variable	Reservoir temperature	F°
ATOTACRES	Input	Total area	Acres
ATOTCONV	Input	Number of conversions from producing wells to injecting wells per pattern	
ATOTINJ	Input	Number of new injectors drilled per pattern	
ATOTPAT	Input	Total number of patterns	
ATOTPROD	Input	Number of new producers drilled per pattern	
ATOTPS	Input	Number of primary wells converted to secondary wells per pattern	
AVDP	Input	Dykstra Parsons coefficient	
AWATINJ	Input	Annual water injected	MBbl
AWOR	Input	Water/oil ratio	Bbl/Bbl
BAS_PLAY	Input	Basin number	
BASEGAS	Input	Base natural gas price used for normalization of capital and operating costs	$/Mcf
BASEOIL	Input	Base crude oil price used for normalization of capital and operating costs	K$
BSE_AVAILCO2	Variable	Base annual volume of CO_2 available by region	Bcf
CAP_BASE	Variable	Capital to be depreciated	K$
CAPMUL	Input	Capital constraints multiplier	
CATCF	Variable	Cumulative discounted cashflow	K$
CHG_ANNSEC_FAC	Input	Change in annual secondary operating cost	Fraction
CHG_CHMPNT_FAC	Input	Change in chemical handling plant cost	Fraction
CHG_CMP_FAC	Input	Change in compression cost	Fraction
CHG_CO2PNT_FAC	Input	Change in CO_2 injection/recycling plant cost	Fraction
CHG_COMP_FAC	Input	Change in completion cost	Fraction
CHG_DRL_FAC	Input	Change in drilling cost	Fraction
CHG_FAC_FAC	Input	Change in facilities cost	Fraction

CHG_FACUPG_FAC	Input	Change in facilities upgrade cost	Fraction
CHG_FOAM_FAC	Input	Change in fixed annual O & M cost	Fraction
CHG_GNA_FAC	Input	Change in G & A cost	Fraction
CHG_INJC_FAC	Input	Change in injection cost	Fraction
CHG_INJCONV_FAC	Input	Change in injector conversion cost	Fraction
CHG_INJT_FAC	Input	Change in injectant cost	Fraction
CHG_LFT_FAC	Input	Change in lifting cost	Fraction
CHG_OGAS_FAC	Input	Change in natural gas O & M cost	K$
CHG_OINJ_FAC	Input	Change in injection O & M cost	K$
CHG_OOIL_FAC	Input	Change in oil O & M cost	K$
CHG_OWAT_FAC	Input	Change in water O & M cost	K$
CHG_PLYPNT_FAC	Input	Change in polymer handling plant cost	Fraction
CHG_PRDWAT_FAC	Input	Change in produced water handling plant cost	Fraction
CHG_SECWRK_FAC	Input	Change in secondary workover cost	Fraction
CHG_SECCONV_FAC	Input	Change in secondary conversion cost	Fraction
CHG_STM_FAC	Input	Change in stimulation cost	Fraction
CHG_STMGEN_FAC	Input	Change in steam generation and distribution cost	Fraction
CHG_VOAM_FAC	Input	Change in variable O & M cost	Fraction
.CHG_WRK_FAC	Input	Change in workover cost	Fraction
CHM_F	Variable	Cost for a chemical handling plant	K$
CHMA	Input	Chemical handling plant	
CHMB	Input	Chemical handling plant	
CHMK	Input	Chemical handling plant	
CIDC	Input	Capitalize intangible drilling costs	K$
CO2_F	Variable	Cost for a CO_2 recycling/injection plant	K$
CO2_RAT_ FAC	Input	CO_2 injection factor	
CO2AVAIL	Variable	Total CO_2 available in a region across all sources	Bcf/Yr
CO2BASE	Input	Total Volume of CO_2 Available	Bcf/Yr
CO2COST	Variable	Final cost for CO_2	$/Mcf

CO2B	Input	Constant and coefficient for natural CO_2 cost equation	
CO2K	Input	Constant and coefficient for natural CO_2 cost equation	
CO2MUL	Input	CO_2 availability constraint multiplier	
CO2OAM	Variable	CO_2 variable O & M cost	K$
CO2OM_20	Input	The O & M cost for CO_2 injection < 20 MMcf	K$
CO2OM20	Input	The O & M cost for CO_2 injection > 20 MMcf	K$
CO2PR	Input	State/regional multipliers for natural CO_2 cost	
CO2PRICE	Input	CO_2 price	$/Mcf
CO2RK, CO2RB	Input	CO_2 recycling plant cost	K$
CO2ST	Input	State code for natural CO_2 cost	
COI	Input	Capitalize other intangibles	
COMP	Variable	Compressor cost	K$
COMP_OAM	Variable	Compressor O & M cost	K$
COMP_VC	Input	Compressor O & M costs	K$
COMP_W	Variable	Compression cost to bring natural gas up to pipeline pressure	K$
COMYEAR_FAC	Input	Number of years of technology commercialization for the penetration curve	Years
CONTIN_ FAC	Input	Continuity increase factor	
COST_BHP	Input	Compressor Cost	$/Bhp
COTYPE	Variable	CO_2 source, either industrial or natural	
CPI_2003	Variable	CPI conversion for 2003$	
CPI_2005	Variable	CPI conversion for 2005$	
CPI_AVG	Input	Average CPI from 1990 to 2010	
CPI_FACTOR	Input	CPI factor from 1990 to 2010	
CPI_YEAR	Input	Year for CPI index	
CREDAMT	Input	Flag that allows AMT to be credited in future years	
CREGPR	Input	The CO_2 price by region and source	$/Mcf
CST_ANNSEC_ FAC	Input	Well level cost to apply secondary producer technology	K$
CST_ANNSEC_CSTP	Variable	Project level cost to apply secondary producer technology	K$

CST_CMP_CSTP	Variable	Project level cost to apply compression technology	K$
CST_CMP_FAC	Input	Well level cost to apply compression technology	K$
CST_COMP_ FAC	Input	Well level cost to apply completion technology	K$
CST_COMP_CSTP	Variable	Project level cost to apply completion technology	K$
CST_DRL_ FAC	Input	Well level cost to apply drilling technology	K$
CST_DRL_CSTP	Variable	Project level cost to apply drilling technology	K$
CST_FAC_ FAC	Input	Well level cost to apply facilities technology	K$
CST_FAC_CSTP	Variable	Project level cost to apply facilities technology	K$
CST_FACUPG_ FAC	Input	Well level cost to apply facilities upgrade technology	K$
CST_FACUPG_CSTP	Variable	Project level cost to apply facilities upgrade technology	K$
CST_FOAM_ FAC	Input	Well level cost to apply fixed annual O & M technology	K$
CST_FOAM_CSTP	Variable	Project level cost to apply fixed annual O & M technology	K$
CST_GNA_ FAC	Input	Well level cost to apply G & A technology	K$
CST_GNA_CSTP	Variable	Project level cost to apply G & A technology	K$
CST_INJC_ FAC	Input	Well level cost to apply injection technology	K$
CST_INJC_CSTP	Variable	Project level cost to apply injection technology	K$
CST_INJCONV_ FAC	Input	Well level cost to apply injector conversion technology	K$
CST_INJCONV_CSTP	Variable	Project level cost to apply injector conversion technology	K$
CST_LFT_ FAC	Input	Well level cost to apply lifting technology	K$
CST_LFT_CSTP	Variable	Project level cost to apply lifting technology	K$
CST_SECCONV_ FAC	Input	Well level cost to apply secondary conversion technology	K$

CST_SECCONV_CSTP	Variable	Project level cost to apply secondary conversion technology	K$
CST_SECWRK_ FAC	Input	Well level cost to apply secondary workover technology	K$
CST_SECWRK_CSTP	Variable	Project level cost to apply secondary workover technology	K$
CST_STM_ FAC	Input	Well level cost to apply stimulation technology	K$
CST_STM_CSTP	Variable	Project level cost to apply stimulation technology	K$
CST_VOAM_ FAC	Input	Well level cost to apply variable annual O & M technology	K$
CST_VOAM_CSTP	Variable	Project level cost to apply variable annual O & M technology	K$
CST_WRK_ FAC	Input	Well level cost to apply workover technology	K$
CST_WRK_CSTP	Variable	Project level cost to apply workover technology	K$
CSTP_ANNSEC_ FAC	Input	Project level cost to apply secondary producer technology	K$
CSTP_CMP_ FAC	Input	Project level cost to apply compression technology	K$
CSTP_COMP_ FAC	Input	Project level cost to apply completion technology	K$
CSTP_DRL_ FAC	Input	Project level cost to apply drilling technology	K$
CSTP_FAC_ FAC	Input	Project level cost to apply facilities technology	K$
CSTP_FACUPG_ FAC	Input	Project level cost to apply facilities upgrade technology	K$
CSTP_FOAM_ FAC	Input	Project level cost to apply fixed annual O & M technology	K$
CSTP_GNA_ FAC	Input	Project level cost to apply G & A technology	K$
CSTP_INJC_ FAC	Input	Project level cost to apply injection technology	K$
CSTP_INJCONV_ FAC	Input	Project level cost to apply injector conversion technology	K$
CSTP_LFT_ FAC	Input	Project level cost to apply lifting technology	K$

CSTP_SECCONV_ FAC	Input	Project level cost to apply secondary conversion technology	K$
CSTP_SECWRK_ FAC	Input	Project level cost to apply secondary workover technology	K$
CSTP_STM_ FAC	Input	Project level cost to apply stimulation technology	K$
CSTP_VOAM_ FAC	Input	Project level cost to apply variable annual O & M technology	K$
CSTP_WRK_ FAC	Input	Project level cost to apply workover technology	K$
CUTOIL	Input	Base crude oil price for the adjustment term of price normalization	$/Bbl
DATCF	Variable	Discounted cashflow after taxes	K$
DEP_CRD	Variable	Depletion credit	K$
DEPLET	Variable	Depletion allowance	K$
DEPR	Variable	Depreciation amount	K$
DEPR_OVR	Input	Annual fraction to depreciate	
DEPR_PROC	Input	Process number for override schedule	
DEPR_YR	Input	Number of years for override schedule	
DEPRSCHL	Input	Annual Fraction Depreciated	Fraction
DEPR_SCH	Variable	Process specific depreciation schedule	Years
DGGLA	Variable	Depletion base (G & G and lease acquisition cost)	K$
DISC_DRL	Variable	Discounted drilling cost	K$
DISC_FED	Variable	Discounted federal tax payments	K$
DISC_GAS	Variable	Discounted revenue from natural gas sales	K$
DISC_INV	Variable	Discounted investment rate	K$
DISC_NDRL	Variable	Discounted project facilities costs	K$
DISC_OAM	Variable	Discounted O & M cost	K$
DISC_OIL	Variable	Discounted revenue from crude oil sales	K$
DISC_ROY	Variable	Discounted royalty	K$
DISC_ST	Variable	Discounted state tax rate	K$
DISCLAG	Input	Number of years between discovery and first production	
DISCOUNT_RT	Input	Process discount rates	Percent

DRCAP_D	Variable	Regional dual use drilling footage for crude oil and natural gas development	Ft
DRCAP_G	Variable	Regional natural gas well drilling footage constraints	Ft
DRCAP_O	Variable	Regional crude oil well drilling footage constraints	Ft
DRILL_FAC	Input	Drilling rate factor	
DRILL_OVER	Input	Drilling constraints available for footage over run	%
DRILL_RES	Input	Development drilling constraints available for transfer between crude oil and natural gas	%
DRILL_TRANS	Input	Drilling constraints transfer between regions	%
DRILLCST	Variable	Drill cost by project	K$
DRILLL48	Variable	Successful well drilling costs	1987$ per well
DRL_CST	Variable	Drilling cost	K$
DRY_CST	Variable	Dryhole drilling cost	K$
DRY_DWCA	Estimated	Dryhole well cost	K$
DRY_DWCB	Estimated	Dryhole well cost	K$
DRY_DWCC	Estimated	Dryhole well cost	K$
DRY_DWCD	Input	Maximum depth range for dry well drilling cost equations	Ft
DRY_DWCK	Estimated	Constant for dryhole drilling cost equation	
DRY_DWCM	Input	Minimum depth range for dry well drilling equations	Ft
DRY_W	Variable	Cost to drill a dry well	K$
DRYCST	Variable	Dryhole cost by project	K$
DRYL48	Variable	Dry well drilling costs	1987$ per well
DRYWELLL48	Variable	Dry Lower 48 onshore wells drilled	Wells
DWC_W	Variable	Cost to drill and complete a crude oil well	K$
EADGGLA	Variable	G&G and lease acquisition cost depletion	K$
EADJGROSS	Variable	Adjusted revenue	K$
EAMINT	Variable	Alternative minimum tax	K$
EAMOR	Variable	Amortization	K$
EAOAM	Variable	Fixed annual operating cost	K$
EATCF	Variable	After tax cash flow	K$
ECAP_BASE	Variable	Depreciable/capitalized base	K$

ECATCF	Variable	Cumulative discounted after tax cashflow	K$
ECO2CODE	Variable	CO_2 source code	
ECO2COST	Variable	CO_2 cost	K$
ECO2INJ	Variable	Economic CO_2 injection	Bcf/Yr
ECO2LIM	Variable	Source specific project life for CO_2 EOR projects	
ECO2POL	Variable	Injected CO_2	MMcf
ECO2RANKVAL	Variable	Source specific ranking value for CO_2 EOR projects	
ECO2RCY	Variable	CO_2 recycled	Bcf/Yr
ECOMP	Variable	Compressor tangible capital	K$
EDATCF	Variable	Discounted after tax cashflow	K$
EDEP_CRD	Variable	Adjustment to depreciation base for federal tax credits	K$
EDEPGGLA	Variable	Depletable G & G/lease cost	K$
EDEPLET	Variable	Depletion	K$
EDEPR	Variable	Depreciation	K$
EDGGLA	Variable	Depletion base	K$
EDRYHOLE	Variable	Number of dryholes drilled	
EEC	Input	Expensed environmental costs	K$
EEGGLA	Variable	Expensed G & G and lease acquisition cost	K$
EEORTCA	Variable	Tax credit addback	K$
EEXIST_ECAP	Variable	Environmental existing capital	K$
EEXIST_EOAM	Variable	Environmental existing O & M costs	K$
EFEDCR	Variable	Federal tax credits	K$
EFEDROY	Variable	Federal royalty	K$
EFEDTAX	Variable	Federal tax	K$
EFOAM	Variable	CO_2 FOAM cost	K$
EGACAP	Variable	G & A capitalized	K$
EGAEXP	Variable	G & A expensed	K$
EGASPRICE2	Variable	Natural gas price used in the economics	K$
EGG	Variable	Expensed G & G cost	K$
EGGLA	Variable	Expensed G & G and lease acquisition cost	K$
EGGLAADD	Variable	G & G/lease addback	K$
EGRAVADJ	Variable	Gravity adjustment	K$
EGREMRES	Variable	Remaining proven natural gas reserves	Bcf
EGROSSREV	Variable	Gross revenues	K$
EIA	Variable	Environmental intangible addback	K$

EICAP	Variable	Environmental intangible capital	
EICAP2	Variable	Environmental intangible capital	
EIGEN	Variable	Number of steam generators	
EIGREMRES	Variable	Remaining inferred natural gas reserves	Bcf
EII	Variable	Intangible investment	K$
EIIDRL	Variable	Intangible investment drilling	K$
EINJCOST	Variable	CO_2/Polymer cost	K$
EINJDR	Variable	New injection wells drilled per year	
EINJWELL	Variable	Active injection wells per year	
EINTADD	Variable	Intangible addback	K$
EINTCAP	Variable	Tangible investment drilling	K$
EINVEFF	Variable	Investment efficiency	
EIREMRES	Variable	Remaining inferred crude oil reserves	MMBbl
EITC	Input	Environmental intangible tax credit	K$
EITCAB	Input	Environmental intangible tax credit rate addback	%
EITCR	Input	Environmental intangible tax credit rate	K$
ELA	Variable	Lease and acquisition cost	K$
ELYRGAS	Variable	Last year of historical natural gas production	MMcf
ELYROIL	Variable	Last year of historical crude oil production	MBbl
ENETREV	Variable	Net revenues	K$
ENEW_ECAP	Variable	Environmental new capital	K$
ENEW_EOAM	Variable	Environmental new O & M costs	K$
ENIAT	Variable	Net income after taxes	K$
ENIBT	Variable	Net income before taxes	K$
ENPV	Variable	Net present value	K$
ENV_FAC	Input	Environmental capital cost multiplier	
ENVOP_FAC	Input	Environmental operating cost multiplier	
ENVSCN	Input	Include environmental costs?	
ENYRSI	Variable	Number of years project is economic	
EOAM	Variable	Variable operating and maintenance	K$

EOCA	Variable	Environmental operating cost addback	K$
EOCTC	Input	Environmental operating cost tax credit	K$
EOCTCAB	Input	Environmental operating cost tax credit rate addback	%
EOCTCR	Input	Environmental operating cost tax credit rate	K$
EOILPRICE2	Variable	Crude oil price used in the economics	K$
EORTC	Input	EOR tax credit	K$
EORTCA	Variable	EOR tax credit addback	K$
EORTCAB	Input	EOR tax credit rate addback	%
EORTCP	Input	EOR tax credit phase out crude oil price	K$
EORTCR	Input	EOR tax credit rate	K$
EORTCRP	Input	EOR tax credit applied by year	%
EOTC	Variable	Other tangible capital	K$
EPROC_OAM	Variable	Natural gas processing cost	K$
EPRODDR	Variable	New production wells drilled per year	
EPRODGAS	Variable	Economic natural gas production	MMcf
EPRODOIL	Variable	Economic crude oil production	MBbl
EPRODWAT	Variable	Economic water production	MBbl
EPRODWELL	Variable	Active producing wells per year	
EREMRES	Variable	Remaining proven crude oil reserves	MMBbl
EROR	Variable	Rate of return	
EROY	Variable	Royalty	K$
ESEV	Variable	Severance tax	K$
ESHUTIN	Variable	New shut in wells drilled per year	
ESTIM	Variable	Stimulation cost	K$
ESTTAX	Variable	State tax	K$
ESUMP	Variable	Number of patterns	
ESURFVOL	Variable	Total volume injected	MMcf/ MBbl/ MLbs
ETAXINC	Variable	Net income before taxes	K$
ETCADD	Variable	Tax credit addbacks taken from NIAT	K$
ETCI	Variable	Federal tax credit	K$
ETCIADJ	Variable	Adjustment for federal tax credit	K$

ETI	Variable	Tangible investments	K$
ETOC	Variable	Total operating cost	K$
ETORECY	Variable	CO_2/Surf/Steam recycling volume	Bcf/MBbl/Yr
ETORECY_CST	Variable	CO_2/Surf/Steam recycling cost	Bcf/MBbl/Yr
ETTC	Input	Environmental tangible tax credit	K$
ETTCAB	Input	Environmental tangible tax credit rate addback	%
ETTCR	Input	Environmental tangible tax credit rate	K$
EWATINJ	Variable	Economic water injected	MBbl
EX_CONRES	Variable	Number of exploration reservoirs	
EX_FCRES	Variable	First exploration reservoir	
EXIST_ECAP	Variable	Existing environmental capital cost	K$
EXIST_EOAM	Variable	Existing environmental O & M cost	K$
EXP_ADJ	Input	Fraction of annual crude oil exploration drilling which is made available	Fraction
EXP_ADJG	Input	Fraction of annual natural gas exploration drilling which is made available	Fraction
EXPA0	Estimated	Crude oil exploration well footage A0	
EXPA1	Estimated	Crude oil exploration well footage A1	
EXPAG0	Input	Natural gas exploration well footage A0	
EXPAG1	Input	Natural gas exploration well footage A1	
EXPATN	Variable	Number of active patterns	
EXPCDRCAP	Variable	Regional conventional exploratory drilling footage constraints	Ft
EXPCDRCAPG	Variable	Regional conventional natural gas exploration drilling footage constraint	Ft
EXPGG	Variable	Expensed G & G cost	K$
EXPL_FRAC	Input	Exploration drilling for conventional crude oil	%
EXPL_FRACG	Input	Exploration drilling for conventional natural gas	%

EXPL_MODEL	Input	Selection of exploration models	
EXPLA	Variable	Expensed lease purchase costs	K$
EXPLR_ FAC	Input	Exploration factor	
EXPLR_CHG	Variable	Change in exploration rate	
EXPLSORTIRES	Variable	Sort pointer for exploration	
EXPMUL	Input	Exploration constraint multiplier	
EXPRDL48	Variable	Expected Production	Oil-MMB Gas-BCF
EXPUDRCAP	Variable	Regional continuous exploratory drilling footage constraints	Ft
EXPUDRCAPG	Variable	Regional continuous natural gas exploratory drilling footage constraints	Ft
FAC_W	Variable	Facilities upgrade cost	K$
FACCOST	Variable	Facilities cost	K$
FACGA	Estimated	Natural gas facilities costs	
FACGB	Estimated	Natural gas facilities costs	
FACGC	Estimated	Natural gas facilities costs	
FACGD	Input	Maximum depth range for natural gas facilities costs	Ft
FACGK	Estimated	Constant for natural gas facilities costs	
FACGM	Input	Minimum depth range for natural gas facilities costs	Ft
FACUPA	Estimated	Facilities upgrade cost	
FACUPB	Estimated	Facilities upgrade cost	
FACUPC	Estimated	Facilities upgrade cost	
FACUPD	Input	Maximum depth range for facilities upgrade cost	Ft
FACUPK	Estimated	Constant for facilities upgrade costs	
FACUPM	Input	Minimum depth range for facilities upgrade cost	Ft
FCO2	Variable	Cost multiplier for natural CO_2	
FEDRATE	Input	Federal income tax rate	Percent
FEDTAX	Variable	Federal tax	K$
FEDTAX_CR	Variable	Federal tax credits	K$
FIRST_ASR	Variable	First year a decline reservoir will be considered for ASR	
FIRST_DEC	Variable	First year a decline reservoir will be considered for EOR	

FIRSTCOM_FAC	Input	First year of commercialization for technology on the penetration curve	
FIT	Variable	Federal income tax	K$
FOAM	Variable	CO_2 fixed O & M cost	K$
FOAMG_1	Variable	Fixed annual operating cost for natural gas 1	K$
FOAMG_2	Variable	Fixed annual operating cost for natural gas 2	K$
FOAMG_W	Variable	Fixed operating cost for natural gas wells	K$
FGASPRICE	Input	Fixed natural gas price	$/MCF
FOILPRICE	Input	Fixed crude oil price	$/BBL
FPLY	Variable	Cost multiplier for polymer	
FPRICE	Input	Selection to use fixed prices	
FR1L48	Variable	Finding rates for new field wildcat drilling	Oil-MMB per well Gas-BCF per well
FR2L48	Variable	Finding rates for other exploratory drilling	Oil-MMB per well Gas-BCF per well
FR3L48	Variable	Finding rates for developmental drilling	Oil-MMB per well Gas-BCF per well
FRAC_CO2	Variable	Fraction of CO_2	Fraction
FRAC_H2S	Variable	Fraction of hydrogen sulfide	Fraction
FRAC_N2	Variable	Fraction of nitrogen	Fraction
FRAC_NGL	Variable	NGL yield	Fraction
FWC_W	Variable	Natural gas facilities costs	K$
GA_CAP	Variable	G & A on capital	K$
GA_EXP	Variable	G & A on expenses	K$
GAS_ADJ	Input	Fraction of annual natural gas drilling which is made available	Fraction
GAS_CASE	Input	Filter for all natural gas processes	
GAS_DWCA	Estimated	Horizontal natural gas drilling and completion costs	
GAS_DWCB	Estimated	Horizontal natural gas drilling and completion costs	
GAS_DWCC	Estimated	Horizontal natural gas drilling and completion costs	

GAS_DWCD	Input	Maximum depth range for natural gas well drilling cost equations	Ft
GAS_DWCK	Estimated	Constant for natural gas well drilling cost equations	
GAS_DWCM	Input	Minimum depth range for natural gas well drilling cost equations	Ft
GAS_FILTER	Input	Filter for all natural gas processes	
GAS_OAM	Input	Process specific operating cost for natural gas production	$/Mcf
GAS_SALES	Input	Will produced natural gas be sold?	
GASA0	Estimated	Natural gas footage A0	
GASA1	Estimated	Natural gas footage A1	
GASD0	Input	Natural gas drywell footage A0	
GASD1	Input	Natural gas drywell footage A1	
GASPRICE2	Variable	Natural gas price dummy to shift price track	K$
GASPRICEC	Variable	Annual natural gas prices used by cashflow	K$
GASPRICED	Variable	Annual natural gas prices used in the drilling constraints	K$
GASPRICEO	Variable	Annual natural gas prices used by the model	K$
GASPROD	Variable	Annual natural gas production	MMcf
GG	Variable	G & G cost	K$
GG_FAC	Input	G & G factor	
GGCTC	Input	G & G tangible depleted tax credit	K$
GGCTCAB	Input	G & G tangible tax credit rate addback	%
GGCTCR	Input	G & G tangible depleted tax credit rate	K$
GGETC	Input	G & G intangible depleted tax credit	K$
GGETCAB	Input	G & G intangible tax credit rate addback	%
GGETCR	Input	G & G intangible depleted tax credit rate	K$
GGLA	Variable	G & G and lease acquisition addback	K$
GMULT_INT	Input	Natural gas price adjustment factor, intangible costs	K$

GMULT_OAM	Input	Natural gas price adjustment factor, O & M	K$
GMULT_TANG	Input	Natural gas price adjustment factor, tangible costs	K$
GNA_CAP2	Input	G & A capital multiplier	Fraction
GNA_EXP2	Input	G & A expense multiplier	Fraction
GPROD	Variable	Well level natural gas production	MMcf
GRAVPEN	Variable	Gravity penalty	K$
GREMRES	Variable	Remaining proven natural gas reserves	MMcf
GROSS_REV	Variable	Gross revenue	K$
H_GROWTH	Input	Horizontal growth rate	Percent
H_PERCENT	Input	Crude oil constraint available for horizontal drilling	%
H_SUCCESS	Input	Horizontal development well success rate by region	%
H2SPRICE	Input	H_2S price	$/Metric ton
HOR_ADJ	Input	Fraction of annual horizontal drilling which is made available	Fraction
HOR_VERT	Input	Split between horizontal and vertical drilling	
HORMUL	Input	Horizontal drilling constraint multiplier	
IAMORYR	Input	Number of years in default amortization schedule	
ICAP	Variable	Other intangible costs	K$
ICST	Variable	Intangible cost	K$
IDCA	Variable	Intangible drilling capital addback	K$
IDCTC	Input	Intangible drilling cost tax credit	K$
IDCTCAB	Input	Intangible drilling cost tax credit rate addback	%
IDCTCR	Input	Intangible drilling cost tax credit rate	K$
IDEPRYR	Input	Number of years in default depreciation schedule	
IGREMRES	Variable	Remaining inferred natural gas reserves	MMcf
II_DRL	Variable	Intangible drilling cost	K$
IINFARSV	Variable	Initial inferred AD gas reserves	Bcf
IINFRESV	Variable	Initial inferred reserves	MMBbl
IMP_CAPCR	Input	Capacity for NGL cryogenic expander plant	MMCf/D

IMP_CAPST	Input	Capacity for NGL straight refrigeration	MMCf/D
IMP_CAPSU	Input	Capacity for Claus Sulfur Recovery	Long ton/day
IMP_CAPTE	Input	Natural gas processing plant capacity	MMcf/D
IMP_CO2_LIM	Input	Limit on CO_2 in natural gas	Fraction
IMP_DIS_RATE	Input	Discount rate for natural gas processing plant	
IMP_H2O_LIM	Input	Limit on H_2O in natural gas	Fraction
IMP_H2S_LIM	Input	Limit on H_2S in natural gas	Fraction
IMP_N2_LIM	Input	Limit on N^2 in natural gas	Fraction
IMP_NGL_LIM	Input	Limit on NGL in natural gas	Fraction
IMP_OP_FAC	Input	Natural gas processing operating factor	
IMP_PLT_LFE	Input	Natural gas processing plant life	Years
IMP_THRU	Input	Throughput	
IND_SRCCO2	Input	Use industrial source of CO_2?	
INDUSTRIAL	Variable	Natural or industrial CO_2 source	
INFLFAC	Input	Annual Inflation Factor	
INFR_ADG	Input	Adjustment factor for inferred AD gas reserves	Tcf
INFR_CBM	Input	Adjustment factor for inferred coalbed methane reserves	Tcf
INFR_DNAG	Input	Adjustment factor for inferred deep non-associated gas reserves	Tcf
INFR_OIL	Input	Adjustment factor for inferred crude oil reserves	Bbl?
INFR_SHL	Input	Adjustment factor for inferred shale gas reserves	Tcf
INFR_SNAG	Input	Adjustment factor for inferred shallow non-associated gas reserves	Tcf
INFR_THT	Input	Adjustment factor for inferred tight gas reserves	Tcf
INFARSV	Variable	Inferred AD gas reserves	Bcf
INFRESV	Variable	Inferred reserves, crude oil or natural gas	MMBbl, Bcf
INJ	Variable	Injectant cost	K$
INJ_OAM	Input	Process specific operating cost for injection	$/Bbl
INJ_RATE_FAC	Input	Injection rate increase	fraction
INTADD	Variable	Total intangible addback	K$
INTANG_M	Variable	Intangible cost multiplier	

INTCAP	Variable	Intangible to be capitalized	K$
INVCAP	Variable	Annual total capital investments constraints, used for constraining projects	MM$
IPDR	Input	Independent producer depletion rate	
IRA	Input	Max alternate minimum tax reduction for independents	K$
IREMRES	Variable	Remaining inferred crude oil reserves	MBbl
IUNDARES	Variable	Initial undiscovered resource	MMBbl/Tcf
IUNDRES	Variable	Initial undiscovered resource	MMBbl/Tcf
L48B4YR	Input	First year of analysis	
LA	Variable	Lease and acquisition cost	K$
LACTC	Input	Lease acquisition tangible depleted tax credit	K$
LACTCAB	Input	Lease acquisition tangible credit rate addback	%
LACTCR	Input	Lease acquisition tangible depleted tax credit rate	K$
LAETC	Input	Lease acquisition intangible expensed tax credit	K$
LAETCAB	Input	Lease acquisition intangible tax credit rate addback	%
LAETCR	Input	Lease acquisition intangible expensed tax credit rate	K$
LAST_ASR	Variable	Last year a decline reservoir will be considered for ASR	
LAST_DEC	Variable	Last year a decline reservoir will be considered for EOR	
LBC_FRAC	Input	Lease bonus fraction	Fraction
LEASCST	Variable	Lease cost by project	K$
LEASL48	Variable	Lease equipment costs	1987$/well
MARK_PEN_FAC	Input	Ultimate market penetration	
MAXWELL	Input	Maximum number of dryholes per play per year	
MAX_API_CASE	Input	Maximum API gravity	
MAX_DEPTH_CASE	Input	Maximum depth	
MAX_PERM_CASE	Input	Maximum permeability	
MAX_RATE_CASE	Input	Maximum production rate	
MIN_API_CASE	Input	Minimum API gravity	
MIN_DEPTH_CASE	Input	Minimum depth	
MIN_PERM_CASE	Input	Minimum permeability	
MIN_RATE_CASE	Input	Minimum production rate	
MOB_RAT_ FAC	Input	Change in mobility ratio	
MPRD	Input	Maximum depth range for new producer equations	Ft

N_CPI	Input	Number of years	
N2PRICE	Input	N_2 price	$/Mcf
NAT_AVAILCO2	Input	Annual CO_2 availability by region	Bcf
NAT_DMDGAS	Variable	Annual natural gas demand in region	Bcf/Yr
NAT_DRCAP_D	Variable	National dual use drilling footage for crude oil and natural gas development	Ft
NAT_DRCAP_G	Variable	National natural gas well drilling footage constraints	Ft
NAT_DRCAP_O	Variable	National crude oil well drilling footage constraints	Ft
NAT_DUAL	Variable	National dual use drilling footage for crude oil and natural gas development	Ft
NAT_EXP	Variable	National exploratory drilling constraint	Bcf/Yr
NAT_EXPC	Variable	National conventional exploratory drilling crude oil constraint	MBbl/Yr
NAT_EXPCDRCAP	Variable	National conventional exploratory drilling footage constraints	Ft
NAT_EXPCDRCAPG	Variable	National high-permeability natural gas exploratory drilling footage constraints	Ft
NAT_EXPCG	Variable	National conventional exploratory drilling natural gas constraint	Bcf/Yr
NAT_EXPG	Variable	National natural gas exploration drilling constraint	Bcf/Yr
NAT_EXPU	Variable	National continuous exploratory drilling crude oil constraint	MBbl/Yr
NAT_EXPUDRCAP	Variable	National continuous exploratory drilling footage constraints	Ft
NAT_EXPUDRCAPG	Variable	National continuous natural gas exploratory drilling footage constraints	Ft
NAT_EXPUG	Variable	National continuous exploratory drilling natural gas constraint	Bcf/Yr
NAT_GAS	Variable	National natural gas drilling constraint	Bcf/Yr
NAT_GDR	Variable	National natural gas dry drilling footage	Bcf/Yr

NAT_HGAS	Variable	Annual dry natural gas	MMcf
NAT_HOIL	Variable	Annual crude oil and lease condensates	MBbl
NAT_HOR	Variable	Horizontal drilling constraint	MBbl/Yr
NAT_INVCAP	Input	Annual total capital investment constraint	MM$
NAT_ODR	Variable	National crude oil dry drilling footage	MBbl/Yr
NAT_OIL	Variable	National crude oil drilling constraint	MBbl/Yr
NAT_SRCCO2	Input	Use natural source of CO_2?	
NAT_TOT	Variable	Total national footage	Ft
NET_REV	Variable	Net revenue	K$
NEW_ECAP	Variable	New environmental capital cost	K$
NEW_EOAM	Variable	New environmental O & M cost	K$
NEW_NRES	Variable	New total number of reservoirs	
NGLPRICE	Input	NGL price	$/Gal
NGLPROD	Variable	Annual NGL production	MBbl
NIAT	Variable	Net income after taxes	K$
NIBT	Variable	Net income before taxes	K$
NIBTA	Variable	Net operating income after adjustments before addback	K$
NIL	Input	Net income limitations	K$
NILB	Variable	Net income depletable base	K$
NILL	Input	Net income limitation limit	K$
NOI	Variable	Net operating income	K$
NOM_YEAR	Input	Year for nominal dollars	
NPR_W	Variable	Cost to equip a new producer	K$
NPRA	Estimated	Constant for new producer equipment	
NPRB	Estimated	Constant for new producer equipment	
NPRC	Estimated	Constant for new producer equipment	
NPRK	Estimated	Constant for new producer equipment	
NPRM	Input	Minimum depth range for new producer equations	Ft
NPROD	Variable	Well level NGL production	MMcf
NRDL48	Variable	Proved reserves added by new field discoveries	Oil-MMB Gas-BCF
NREG	Input	Number of regions	

NSHUT	Input	Number of years after economics life in which EOR can be considered	
NTECH	Input	Number of technology impacts	
NUMPACK	Input	Number of packages per play per year	
NWELL	Input	Number of wells in continuous exploration drilling package	
OAM	Variable	Variable O & M cost	K$
OAM_COMP	Variable	Compression O & M	K$
OAM_M	Variable	O & M cost multiplier	
OIA	Variable	Other intangible capital addback	K$
OIL_ADJ	Input	Fraction of annual crude oil drilling which is made available	Fraction
OIL_CASE	Input	Filter for all crude oil processes	
OIL_DWCA	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCB	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCC	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCD	Input	Maximum depth range for crude oil well drilling cost equations	Ft
OIL_DWCK	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCM	Input	Minimum depth range for crude oil well drilling cost equations	Ft
OIL_FILTER	Input	Filter for all crude oil processes	
OIL_OAM	Input	Process specific operating cost for crude oil production	$/Bbl
OIL_RAT_ FAC	Input	Change in crude oil production rate	
OIL_RAT_CHG	Variable	Change in crude oil production rate	
OIL_SALES	Input	Sell crude oil produced from the reservoir?	
OILA0	Estimated	Oil footage A0	
OILA1	Estimated	Oil footage A1	

OILCO2	Input	Fixed crude oil price used for economic pre-screening of industrial CO_2 projects	K$
OILD0	Input	Crude oil drywell footage A0	
OILD1	Input	Crude oil drywell footage A1	
OILPRICEC	Variable	Annual crude oil prices used by cashflow	K$
OILPRICED	Variable	Annual crude oil prices used in the drilling constraints	K$
OILPRICEO	Variable	Annual crude oil prices used by the model	K$
OILPROD	Variable	Annual crude oil production	MBbl
OINJ	Variable	Well level injection	MMcf
OITC	Input	Other intangible tax credit	K$
OITCAB	Input	Other intangible tax credit rate addback	%
OITCR	Input	Other intangible tax credit rate	K$
OMGA	Estimated	Fixed annual cost for natural gas	$/Well
OMGB	Estimated	Fixed annual cost for natural gas	$/Well
OMGC	Estimated	Fixed annual cost for natural gas	$/Well
OMGD	Input	Maximum depth range for fixed annual O & M natural gas cost	Ft
OMGK	Estimated	Constant for fixed annual O & M cost for natural gas	
OMGM	Input	Minimum depth range for fixed annual O & M cost for natural gas	Ft
OML_W	Variable	Variable annual operating cost for lifting	K$
OMLA	Estimated	Lifting cost	$/Well
OMLB	Estimated	Lifting cost	$/Well
OMLC	Estimated	Lifting cost	$/Well
OMLD	Input	Maximum depth range for fixed annual operating cost for crude oil	Ft
OMLK	Estimated	Constant for fixed annual operating cost for crude oil	
OMLM	Input	Minimum depth range for annual operating cost for crude oil	Ft
OMO_W	Variable	Fixed annual operating cost for crude oil	K$

OMOA	Estimated	Fixed annual cost for crude oil	$/Well
OMOB	Estimated	Fixed annual cost for crude oil	$/Well
OMOC	Estimated	Fixed annual cost for crude oil	$/Well
OMOD	Input	Maximum depth range for fixed annual operating cost for crude oil	Ft
OMOK	Estimated	Constant for fixed annual operating cost for crude oil	
OMOM	Input	Minimum depth range for fixed annual operating cost for crude oil	Ft
OMSWRA	Estimated	Secondary workover cost	$/Well
OMSWRB	Estimated	Secondary workover cost	$/Well
OMSWRC	Estimated	Secondary workover cost	$/Well
OMSWRD	Input	Maximum depth range for variable operating cost for secondary workover	Ft
OMSWRK	Estimated	Constant for variable operating cost for secondary workover	
OMSWRM	Input	Minimum depth range for variable operating cost for secondary workover	Ft
OMULT_INT	Input	Crude oil price adjustment factor, intangible costs	
OMULT_OAM	Input	Crude oil price adjustment factor, O & M	
OMULT_TANG	Input	Crude oil price adjustment factor, tangible costs	
OPCOST	Variable	AOAM by project	K$
OPERL48	Variable	Operating Costs	1987$/Well
OPINJ_W	Variable	Variable annual operating cost for injection	K$
OPINJA	Input	Injection cost	$/Well
OPINJB	Input	Injection cost	$/Well
OPINJC	Input	Injection cost	$/Well
OPINJD	Input	Maximum depth range for variable annual operating cost for injection	Ft
OPINJK	Input	Constant for variable annual operating cost for injection	
OPINJM	Input	Minimum depth range for variable annual operating cost for injection	Ft

OPROD	Variable	Well level crude oil production	MBbl
OPSEC_W	Variable	Fixed annual operating cost for secondary operations	K$
OPSECA	Estimated	Annual cost for secondary production	$/Well
OPSECB	Estimated	Annual cost for secondary production	$/Well
OPSECC	Estimated	Annual cost for secondary production	$/Well
OPSECD	Input	Maximum depth range for fixed annual operating cost for secondary operations	Ft
OPSECK	Estimated	Constant for fixed annual operating cost for secondary operations	
OPSECM	Input	Minimum depth range for fixed annual operating cost for secondary operations	Ft
OPT_RPT	Input	Report printing options	
ORECY	Variable	Well level recycled injectant	MBbl
OTC	Variable	Other tangible costs	K$
PATT_DEV	Input	Pattern development	
PATT_DEV_MAX	Input	Maximum pattern development schedule	
PATT_DEV_MIN	Input	Minimum pattern development schedule	
PATDEV	Variable	Annual number of patterns developed for base and advanced technology	
PATN	Variable	Patterns initiated each year	
PATNDCF	Variable	DCF by project	K$
PATTERNS	Variable	Shifted patterns initiated	
PAYCONT_ FAC	Input	Pay continuity factor	
PDR	Input	Percent depletion rate	%
PGGC	Input	Percent of G & G depleted	%
PIIC	Input	Intangible investment to capitalize	%
PLAC	Input	Percent of lease acquisition cost capitalized	%
PLAYNUM	Input	Play number	
PLY_F	Variable	Cost for a polymer handling plant	K$
PLYPA	Input	Polymer handling plant constant	
PLYPK	Input	Polymer handling plant constant	

POLY	Input	Polymer cost	
POLYCOST	Variable	Polymer cost	$/Lb
POTENTIAL	Variable	The number of reservoirs in the resource file	
PRICEYR	Input	First year of prices in price track	K$
PRO_REGEXP	Input	Regional exploration well drilling footage constraint	Ft
PRO_REGEXPG	Input	Regional exploration well drilling footage constraint	Ft
PRO_REGGAS	Input	Regional natural gas well drilling footage constraint	Ft
PRO_REGOIL	Input	Regional crude oil well drilling footage constraint	Ft
PROB_IMP_FAC	Input	Probability of industrial implementation	
PROB_RD_FAC	Input	Probability of successful R & D	
PROC_CST	Variable	Processing cost	$/Mcf
PROC_OAM	Variable	Processing and treating cost	K$
PROCESS_CASE	Input	Filter for crude oil and natural gas processes	
PROCESS_FILTER	Input	Filter for crude oil and natural gas processes	
PROD_IND_ FAC	Input	Production impact	
PROVACC	Input	Year file for resource access	
PROVNUM	Input	Province number	
PRRATL48	Variable	Production to reserves ratio	Fraction
PSHUT	Input	Number of years prior to economic life in which EOR can be considered	
PSI_W	Variable	Cost to convert a primary well to an injection well	K$
PSIA	Estimated	Cost to convert a producer to an injector	
PSIB	Estimated	Cost to convert a producer to an injector	
PSIC	Estimated	Cost to convert a producer to an injector	
PSID	Input	Maximum depth range for producer to injector	Ft
PSIK	Estimated	Constant for producer to injector	
PSIM	Input	Minimum depth range for producer to injector	Ft
PSW_W	Variable	Cost to convert a primary to secondary well	K$

PSWA	Estimated	Cost to convert a primary to secondary well	
PSWB	Estimated	Cost to convert a primary to secondary well	
PSWC	Estimated	Cost to convert a primary to secondary well	
PSWD	Input	Maximum depth range for producer to injector	Ft
PSWK	Estimated	Constant for primary to secondary	
PSWM	Input	Minimum depth range for producer to injector	Ft
PWHP	Input	Produced water handling plant multiplier	K$
PWP_F	Variable	Cost for a produced water handling plant	K$
RDEPTH	Variable	Reservoir depth	ft
RDR	Input	Depth interval	
RDR_FOOTAGE	Variable	Footage available in this interval	Ft
RDR_FT	Variable	Running total of footage used in this bin	Ft
REC_EFF_ FAC	Input	Recovery efficiency factor	
RECY_OIL	Input	Produced water recycling cost	K$
RECY_WAT	Input	Produced water recycling cost	
REG_DUAL	Variable	Regional dual use drilling footage for crude oil and natural gas development	Ft
REG_EXP	Variable	Regional exploratory drilling constraints	MBbl/Yr
REG_EXPC	Variable	Regional conventional crude oil exploratory drilling constraint	MBbl/Yr
REG_EXPCG	Variable	Regional conventional natural gas exploratory drilling constraint	Bcf/Yr
REG_EXPG	Variable	Regional exploratory natural gas drilling constraint	Bcf/Yr
REG_EXPU	Variable	Regional continuous crude oil exploratory drilling constraint	MBbl/Yr
REG_EXPUG	Variable	Regional continuous natural gas exploratory drilling constraint	Bcf/Yr
REG_GAS	Variable	Regional natural gas drilling constraint	Bcf/Yr
REG_HADG	Variable	Regional historical AD gas	MMcf
REG_HCBM	Variable	Regional historical CBM	MMcf

REG_HCNV	Variable	Regional historical high-permeability natural gas	MMcf
REG_HEOIL	Variable	Regional crude oil and lease condensates for continuing EOR	MBbl
REG_HGAS	Variable	Regional dry natural gas	MMcf
REG_HOIL	Variable	Regional crude oil and lease condensates	MBbl
REG_HSHL	Variable	Regional historical shale gas	MMcf
REG_HTHT	Variable	Regional historical tight gas	MMcf
REG_NAT	Input	Regional or national	
REG_OIL	Variable	Regional crude oil drilling constraint	MBbl/Yr
REGDRY	Variable	Regional dryhole rate	
REGDRYE	Variable	Exploration regional dryhole rate	
REGDRYG	Variable	Development natural gas regional dryhole rate	
REGDRYKD	Variable	Regional dryhole rate for discovered development	
REGDRYUD	Variable	Regional dryhole rate for undiscovered development	
REGDRYUE	Variable	Regional dryhole rate for undiscovered exploration	
REGION_CASE	Input	Filter for OLOGSS region	
REGION_FILTER	Input	Filter for OLOGSS region	
REGSCALE_CBM	Input	Regional historical daily CBM gas production for the last year of history	Bcf
REGSCALE_CNV	Input	Regional historical daily high-permeability natural gas production for the last year of history	Bcf
REGSCALE_GAS	Input	Regional historical daily natural gas production for the last year of history	Bcf
REGSCALE_OIL	Input	Regional historical daily crude oil production for the last year of history	MBbl
REGSCALE_SHL	Input	Regional historical daily shale gas production for the last year of history	Bcf
REGSCALE_THT	Input	Regional historical daily tight gas production for the last year of history	Bcf
REM_AMOR	Variable	Remaining amortization base	K$
REM_BASE	Variable	Remaining depreciation base	K$

REMRES	Variable	Remaining proven crude oil reserves	MBbl
RESADL48	Variable	Total additions to proved reserves	Oil-MMB Gas-BCF
RESBOYL48	Variable	End of year reserves for current year	Oil-MMB Gas-BCF
RES_CHR_ FAC	Input	Reservoir characterization cost	$/Cumulative BOE
RES_CHR_CHG	Variable	Reservoir characterization cost	$/Cumulative BOE
RESV_ADGAS	Input	Historical AD gas reserves	Tcf
RESV_CBM	Input	Historical coalbed methane reserves	Tcf
RESV_CONVGAS	Input	Historical high-permeability dry natural gas reserves	Tcf
RESV_OIL	Input	Historical crude oil and lease condensate reserves	BBbl
RESV_SHL	Input	Historical shale gas reserves	Tcf
RESV_THT	Input	Historical tight gas reserves	Tcf
RGR	Input	Annual drilling growth rate	
RIGSL48	Variable	Available rigs	Rigs
RNKVAL	Input	Ranking criteria for the projects	
ROR	Variable	Rate of return	K$
ROYALTY	Variable	Royalty	K$
RREG	Variable	Reservoir region	
RRR	Input	Annual drilling retirement rate	
RUNTYPE	Input	Resources selected to evaluate in the Timing subroutine	
RVALUE	Variable	Reservoir technical crude oil production	MBbl
SCALE_DAY	Input	Number of days in the last year of history	Days
SCALE_GAS	Input	Historical daily natural gas production for the last year of history	Bcf
SCALE_OIL	Input	Historical daily crude oil production for the last year of history	MBbl
SEV_PROC	Variable	Process code	
SEV_TAX	Variable	Severance tax	K$
SFIT	Variable	Alternative minimum tax	K$
SKIN_FAC	Input	Skin factor	
SKIN_CHG	Variable	Change in skin amount	
SMAR	Input	Six month amortization rate	%

SPLIT_ED	Input	Split exploration and development	
SPLIT_OG	Input	Split crude oil and natural gas constraints	
STARTPR	Variable	First year a pattern is initiated	
STATE_TAX	Variable	State tax	K$
STIM	Variable	Stimulation cost	K$
STIM_A, STIM_B	Input	Coefficients for natural gas/oil stimulation cost	K$
STIM_W	Variable	Natural gas well stimulation cost	K$
STIM_YR	Input	Number of years between stimulations of natural gas/oil wells	
STIMFAC	Input	Stimulation efficiency factor	
STL	Variable	State identification number	
STMGA	Input	Steam generator cost multiplier	
STMM_F	Variable	Cost for steam manifolds and generators	K$
STMMA	Input	Steam manifold/pipeline multiplier	
SUCCHDEV	Variable	Horizontal development well success rate by region	Fraction
SUCDEVE	Input	Developmental well dryhole rate by region	%
SUCDEVG	Variable	Final developmental natural gas well success rate by region	Fraction
SUCDEVO	Variable	Final developmental crude oil well success rate by region	Fraction
SUCEXP	Input	Undiscovered exploration well dryhole rate by region	%
SUCEXPD	Input	Exploratory well dryhole rate by region	%
SUCG	Variable	Initial developmental natural gas well success rate by region	Fraction
SUCO	Variable	Initial developmental crude oil well success by region	Fraction
SUCWELLL48	Variable	Successful Lower 48 onshore wells drilled	Wells
SUM_DRY	Variable	Developmental dryholes drilled	
SUM_GAS_CONV	Variable	High-permeability natural gas drilling	MMcf

SUM_GAS_UNCONV	Variable	Low-permeability natural gas drilling	MMcf
SUM_OIL_CONV	Variable	Conventional crude oil drilling	MBbl
SUM_OIL_UNCONV	Variable	Continuous crude oil drilling	MBbl
SUMP	Variable	Total cumulative patterns	
SWK_W	Variable	Secondary workover cost	K$
TANG_FAC_RATE	Input	Percentage of the well costs which are tangible	Percent
TANG_M	Variable	Tangible cost multiplier	
TANG_RATE	Input	Percentage of drilling costs which are tangible	Percent
TCI	Variable	Total capital investments	K$
TCIADJ	Variable	Adjusted capital investments	K$
TCOII	Input	Tax credit on intangible investments	K$
TCOTI	Input	Tax credit on tangible investments	K$
TDTC	Input	Tangible development tax credit	K$
TDTCAB	Input	Tangible development tax credit rate addback	%
TDTCR	Input	Tangible development tax credit rate	K$
TECH01_FAC	Input	WAG ratio applied to CO2EOR	
TECH02_FAC	Input	Recovery Limit	
TECH03_FAC	Input	Vertical Skin Factor for natural gas	
TECH04_FAC	Input	Fracture Half Length	Ft
TECH05_FAC	Input	Fracture Conductivity	Ft
TECH_CO2FLD	Variable	Technical production from CO_2 flood	MBbl
TECH_COAL	Variable	Annual technical coalbed methane gas production	MMcf
TECH_CURVE	Variable	Technology commercialization curve for market penetration	
TECH_CURVE_FAC	Input	Technology commercialization curve for market penetration	
TECH_DECLINE	Variable	Technical decline production	MBbl
TECH_GAS	Variable	Annual technical natural gas production	MMcf
TECH_HORCON	Variable	Technical production from horizontal continuity	MBbl

TECH_HORPRF	Variable	Technical production for horizontal profile	MBbl
TECH_INFILL	Variable	Technical production from infill drilling	MBbl
TECH_NGL	Variable	Annual technical NGL production	MBbl
TECH_OIL	Variable	Annual technical crude oil production	MBbl
TECH_PLYFLD	Variable	Technical production from polymer injection	MBbl
TECH_PRFMOD	Variable	Technical production from profile modification	MBbl
TECH_PRIMARY	Variable	Technical production from primary sources	MBbl
TECH_RADIAL	Variable	Technical production from conventional radial flow	MMcf
TECH_SHALE	Variable	Annual technical shale gas production	MMcf
TECH_STMFLD	Variable	Technical production from steam flood	MBbl
TECH_TIGHT	Variable	Annual technical tight gas production	MMcf
TECH_TIGHTG	Variable	Technical tight gas production	MMcf
TECH_UCOALB	Variable	Technical undiscovered coalbed methane production	MMcf
TECH_UCONTO	Variable	Technical undiscovered continuous crude oil production	MBbl
TECH_UCONVG	Variable	Technical low-permeability natural gas production	MMcf
TECH_UCONVO	Variable	Technical undiscovered conventional crude oil production	MBbl
TECH_UGCOAL	Variable	Annual technical developing coalbed methane gas production	MMcf
TECH_UGSHALE	Variable	Annual technical developing shale gas production	MMcf
TECH_UGTIGHT	Variable	Annual technical developing tight gas production	MMcf
TECH_USHALE	Variable	Technical undiscovered shale gas production	MMcf
TECH_UTIGHT	Variable	Technical undiscovered tight gas production	MMcf
TECH_WATER	Variable	Technical production from waterflood	MBbl

TECH_WTRFLD	Variable	Technical production from waterflood	MBbl
TGGLCD	Variable	Total G & G cost	K$
TI	Variable	Tangible costs	K$
TI_DRL	Variable	Tangible drilling cost	K$
TIMED	Variable	Timing flag	
TIMEDYR	Variable	Year in which the project is timed	
TOC	Variable	Total operating costs	K$
TORECY	Variable	Annual water injection	MBbl
TORECY_CST	Variable	Water injection cost	K$
TOTHWCAP	Variable	Total horizontal drilling footage constraint	Ft
TOTINJ	Variable	Annual water injection	MBbl
TOTMUL	Input	Total drilling constraint multiplier	
TOTSTATE	Variable	Total state severance tax	K$
UCNT	Variable	Number of undiscovered reservoirs	
UDEPTH	Variable	Reservoir depth	K$
UMPCO2	Input	CO_2 ultimate market acceptance	
UNAME	Variable	Reservoir identifier	
UNDARES	Variable	Undiscovered resource, AD gas or lease condensate	Bcf, MMBbl
UNDRES	Variable	Undiscovered resource	MMBbl, Bcf
UREG	Variable	Reservoir region	
USE_AVAILCO2	Variable	Used annual volume of CO_2 by region	Bcf
USE_RDR	Input	Use rig depth rating	
USEAVAIL	Variable	Used annual CO_2 volume by region across all sources	Bcf
USECAP	Variable	Annual total capital investment constraints, used by projects	MM$
UVALUE	Variable	Reservoir undiscovered crude oil production	MBbl
UVALUE2	Variable	Reservoir undiscovered natural gas production	MMcf
VEORCP	Input	Volumetric EOR cutoff	%
VIABLE	Variable	The number of economically viable reservoirs	
VOL_SWP_ FAC	Input	Sweep volume factor	
VOL_SWP_CHG	Variable	Change in sweep volume	
WAT_OAM	Input	Process specific operating cost for water production	$/Bbl
WATINJ	Variable	Annual water injection	MBbl

WATPROD	Variable	Annual water production	MBbl
WELLSL48	Variable	Lower 48 onshore wells drilled	Wells
WINJ	Variable	Well level water injection	MBbl
WPROD	Variable	Well level water production	MBbl
WRK_W	Variable	Cost for well workover	K$
WRKA	Estimated	Constant for workover cost equations	
WRKB	Estimated	Constant for workover cost equations	
WRKC	Estimated	Constant for workover cost equations	
WRKD	Input	Maximum depth range for workover cost	Ft
WRKK	Estimated	Constant for workover cost equations	
WRKM	Input	Minimum depth range for workover cost	Ft
XCAPBASE	Variable	Cumulative cap stream	
XCUMPROD	Variable	Cumulative production	MBbl
XPATN	Variable	Active patterns each year	
XPP1	Variable	Number of new producers drilled per pattern	
XPP2	Variable	Number of new injectors drilled per pattern	
XPP3	Variable	Number of producers converted to injectors	
XPP4	Variable	Number of primary wells converted to secondary wells	
XROY	Input	Royalty rate	Percent
YEARS_STUDY	Input	Number of years of analysis	
YR1	Input	Number of years for tax credit on tangible investments	
YR2	Input	Number of years for tax credit on intangible investments	
YRDI	Input	Years to develop infrastructure	
YRDT	Input	Years to develop technology	
YRMA	Input	Years to reach full capacity	

Appendix 2.B: Cost and Constraint Estimation

The major sections of OLOGSS consist of a series of equations that are used to calculate project economics and the development of crude oil and natural gas resources subject to the availability of regional development constraints. The cost and constraint calculation was assessed as unit costs per well. The product of the cost equation and cost adjustment factor is the actual cost. The actual cost reflects the influence on the resource, region and oil or gas price. The equations, the estimation techniques, and the statistical results for these equations are documented below. The statistical software included within Microsoft Excel was used for the estimations.

Drilling and Completion Costs for Crude Oil

The 2004 – 2007 Joint Association Survey (JAS) data was used to calculate the equation for vertical drilling and completion costs for crude oil. The data was analyzed at a regional level. The independent variables were depth, raised to powers of 1 through 3. Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. The method of estimation used was ordinary least squares. The form of the equation is given below. β1 (the coefficient for depth raised to the first power) is statistically insignificant and is therefore assumed zero.

$$\text{Drilling Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \quad (2.B\text{-}1)$$

where Drilling Cost = DWC_W
β0 = OIL_DWCK
β1 = OIL_DWCA
β2 = OIL_DWCB
β3 = OIL_DWCC
from equations 2-17 and 2-18 in Chapter 2.

Northeast Region:

Regression Statistics	
Multiple R	0.836438789
R Square	0.699629848
Adjusted R Square	0.691168717
Standard Error	629377.1735
Observations	74

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	6.55076E+13	3.27538E+13	82.6875087	2.86296E-19
Residual	71	2.81242E+13	3.96116E+11		
Total	73	9.36318E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	122428.578	126464.5594	0.968086068	0.336287616	-129734.7159	374591.8719	-129734.7159	374591.8719
β2	0.058292022	0.020819613	2.799860932	0.006580083	0.016778872	0.099805172	0.016778872	0.099805172
β3	5.68014E-07	2.56497E-06	0.221450391	0.825377435	-4.5464E-06	5.68243E-06	-4.5464E-06	5.68243E-06

Gulf Coast Region:

Regression Statistics	
Multiple R	0.927059199
R Square	0.859438758
Adjusted R Square	0.85771408
Standard Error	754021.7218
Observations	166

ANOVA

	df	SS	MS	F	Significance F
Regression	2	5.66637E+14	2.83318E+14	498.3184388	3.55668E-70
Residual	163	9.26734E+13	5.68549E+11		
Total	165	6.5931E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	171596.0907	99591.43949	1.723000407	0.086784881	-25059.61405	368251.7955	-25059.61405	368251.7955
β2	0.026582707	0.005213357	5.098961204	9.38664E-07	0.016288283	0.036877131	0.016288283	0.036877131
β3	5.10946E-07	3.82305E-07	1.336488894	0.183252113	-2.43962E-07	1.26585E-06	-2.43962E-07	1.26585E-06

Mid-Continent Region:

Regression Statistics	
Multiple R	0.898305188
R Square	0.806952211
Adjusted R Square	0.803343841
Standard Error	865339.0638
Observations	110

ANOVA

	df	SS	MS	F	Significance F
Regression	2	3.34919E+14	1.67459E+14	223.6334505	6.06832E-39
Residual	107	8.01229E+13	7.48812E+11		
Total	109	4.15042E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	44187.62539	135139.2151	0.326978556	0.744322892	-223710.0994	312085.3502	-223710.0994	312085.3502
β2	0.038468835	0.005870927	6.552429326	2.04023E-09	0.026830407	0.050107263	0.026830407	0.050107263
β3	-9.45921E-07	3.70017E-07	-2.556425591	0.011978314	-1.67944E-06	-2.12405E-07	-1.67944E-06	-2.12405E-07

Southwest Region:

Regression Statistics	
Multiple R	0.927059199
R Square	0.859438758
Adjusted R Square	0.85771408
Standard Error	754021.7218
Observations	166

ANOVA

	df	SS	MS	F	Significance F
Regression	2	5.66637E+14	2.83318E+14	498.3184388	3.55668E-70
Residual	163	9.26734E+13	5.68549E+11		
Total	165	6.5931E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	171596.0907	99591.43949	1.723000407	0.086784881	-25059.61405	368251.7955	-25059.61405	368251.7955
β2	0.026582707	0.005213357	5.098961204	9.38664E-07	0.016288283	0.036877131	0.016288283	0.036877131
β3	5.10946E-07	3.82305E-07	1.336488894	0.183252113	-2.43962E-07	1.26585E-06	-2.43962E-07	1.26585E-06

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.905358855
R Square	0.819674657
Adjusted R Square	0.81505093
Standard Error	1524859.577
Observations	81

ANOVA

	df	SS	MS	F	Significance F
Regression	2	8.24402E+14	4.12201E+14	177.2757561	9.68755E-30
Residual	78	1.81365E+14	2.3252E+12		
Total	80	1.00577E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	85843.77642	334865.8934	0.256352702	0.798353427	-580822.9949	752510.5477	-580822.9949	752510.5477
β2	0.024046279	0.017681623	1.35995883	0.177760898	-0.011155127	0.059247685	-0.011155127	0.059247685
β3	3.11588E-06	1.35985E-06	2.291329746	0.024643617	4.08613E-07	5.82314E-06	4.08613E-07	5.82314E-06

West Coast Region:

Regression Statistics	
Multiple R	0.829042211
R Square	0.687310988
Adjusted R Square	0.66961161
Standard Error	1192282.08
Observations	57

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1.65605E+14	5.52018E+13	38.83249387	2.05475E-13
Residual	53	7.53414E+13	1.42154E+12		
Total	56	2.40947E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	416130.9988	739996.4118	0.562341914	0.576253925	-1068113.806	1900375.804	-1068113.806	1900375.804
β1	44.24458907	494.4626992	0.089480135	0.929037628	-947.5219666	1036.011145	-947.5219666	1036.011145
β2	0.032683532	0.091113678	0.35871159	0.721235869	-0.150067358	0.215434422	-0.150067358	0.215434422
β3	3.38129E-07	4.76464E-06	0.070966208	0.94369176	-9.21853E-06	9.89479E-06	-9.21853E-06	9.89479E-06

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.847120174
R Square	0.71761259
Adjusted R Square	0.702750095
Standard Error	1967213.576
Observations	61

ANOVA

	df	SS	MS	F	Significance F
Regression	3	5.60561E+14	1.86854E+14	48.2834529	1.1626E-15
Residual	57	2.20586E+14	3.86993E+12		
Total	60	7.81147E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	98507.54357	1384010.586	0.071175426	0.943507284	-2672925.83	2869940.917	-2672925.83	2869940.917
β1	478.7358996	548.203512	0.873281344	0.386173991	-619.0226893	1576.494489	-619.0226893	1576.494489
β2	-0.00832112	0.058193043	-0.142991666	0.886801051	-0.124850678	0.108208438	-0.124850678	0.108208438
β3	6.1159E-07	1.79131E-06	0.34142064	0.7340424	-2.97545E-06	4.19863E-06	-2.97545E-06	4.19863E-06

Drilling and Completion Cost for Oil - Cost Adjustment Factor

The cost adjustment factor for vertical drilling and completion costs for oil was calculated using JAS data through 2007. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Northeast Region:

Regression Statistics	
Multiple R	0.993325966
R Square	0.986696475
Adjusted R Square	0.986411399
Standard Error	0.029280014
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.901997029	2.967332343	3461.175482	4.4887E-131
Residual	140	0.120024694	0.000857319		
Total	143	9.022021723			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309616442	0.009839962	31.46520591	2.3349E-65	0.290162308	0.329070576	0.290162308	0.329070576
β1	0.019837121	0.000434252	45.68110123	5.41725E-86	0.018978581	0.020695661	0.018978581	0.020695661
β2	-0.000142411	5.21769E-06	-27.29392193	6.44605E-58	-0.000152727	-0.000132095	-0.000152727	-0.000132095
β3	3.45898E-07	1.69994E-08	20.34770764	1.18032E-43	3.1229E-07	3.79507E-07	3.1229E-07	3.79507E-07

Gulf Coast Region:

Regression Statistics	
Multiple R	0.975220111
R Square	0.951054265
Adjusted R Square	0.950005428
Standard Error	0.054224144
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	7.998414341	2.666138114	906.7701736	1.76449E-91
Residual	140	0.411636098	0.002940258		
Total	143	8.410050438			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.404677859	0.01822279	22.2072399	1.01029E-47	0.368650426	0.440705292	0.368650426	0.440705292
β1	0.016335847	0.000804199	20.31319148	1.41023E-43	0.014745903	0.017925792	0.014745903	0.017925792
β2	-0.00010587	9.66272E-06	-10.95654411	1.47204E-20	-0.000124974	-8.67663E-05	-0.000124974	-8.67663E-05
β3	2.40517E-07	3.14814E-08	7.639970947	3.10789E-12	1.78277E-07	3.02758E-07	1.78277E-07	3.02758E-07

Mid-Continent Region:

Regression Statistics	
Multiple R	0.973577019
R Square	0.947852212
Adjusted R Square	0.94673476
Standard Error	0.058882142
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.822668656	2.940889552	848.2258794	1.4872E-89
Residual	140	0.485394925	0.003467107		
Total	143	9.308063582			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.309185338	0.019788175	15.62475232	1.738E-32	0.270063053	0.348307623	0.270063053	0.348307623
β1	0.019036286	0.000873282	21.79856116	7.62464E-47	0.017309761	0.020762811	0.017309761	0.020762811
β2	-0.000123667	1.04928E-05	-11.78593913	1.05461E-22	-0.000144412	-0.000102922	-0.000144412	-0.000102922
β3	2.60516E-07	3.41858E-08	7.620611936	3.45556E-12	1.92929E-07	3.28104E-07	1.92929E-07	3.28104E-07

Southwest Region:

Regression Statistics	
Multiple R	0.993452577
R Square	0.986948023
Adjusted R Square	0.986668338
Standard Error	0.030207623
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.66004438	3.220014793	3528.781511	1.1799E-131
Residual	140	0.127750066	0.0009125		
Total	143	9.787794446			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.293837119	0.010151698	28.944627	5.92751E-61	0.273766667	0.313907571	0.273766667	0.313907571
β1	0.020183122	0.00044801	45.05064425	3.35207E-85	0.019297383	0.021068861	0.019297383	0.021068861
β2	-0.000142936	5.38299E-06	-26.55334755	1.63279E-56	-0.000153579	-0.000132294	-0.000153579	-0.000132294
β3	3.44926E-07	1.75379E-08	19.66744699	4.04901E-42	3.10253E-07	3.796E-07	3.10253E-07	3.796E-07

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.993622433
R Square	0.987285538
Adjusted R Square	0.987013086
Standard Error	0.029478386
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.446702681	3.148900894	3623.69457	1.8856E-132
Residual	140	0.121656535	0.000868975		
Total	143	9.568359216			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.297270516	0.009906628	30.00723517	7.63744E-63	0.27768458	0.316856451	0.27768458	0.316856451
β1	0.020126228	0.000437194	46.03497443	1.9664E-86	0.019261872	0.020990585	0.019261872	0.020990585
β2	-0.000143079	5.25304E-06	-27.23739215	8.23219E-58	-0.000153465	-0.000132693	-0.000153465	-0.000132693
β3	3.45557E-07	1.71145E-08	20.19080817	2.6538E-43	3.1172E-07	3.79393E-07	3.1172E-07	3.79393E-07

West Coast Region:

Regression Statistics	
Multiple R	0.993362569
R Square	0.986769193
Adjusted R Square	0.986485676
Standard Error	0.030158697
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.496912448	3.165637483	3480.455028	3.0585E-131
Residual	140	0.127336582	0.000909547		
Total	143	9.62424903			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.297702178	0.010135256	29.37293095	1.01194E-61	0.277664233	0.317740124	0.277664233	0.317740124
β1	0.020091425	0.000447284	44.91872099	4.92225E-85	0.019207121	0.02097573	0.019207121	0.02097573
β2	-0.000142627	5.37427E-06	-26.53879345	1.74092E-56	-0.000153252	-0.000132001	-0.000153252	-0.000132001
β3	3.44597E-07	1.75095E-08	19.68054067	3.78057E-42	3.0998E-07	3.79214E-07	3.0998E-07	3.79214E-07

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.993744864
R Square	0.987528854
Adjusted R Square	0.987261615
Standard Error	0.029293844
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.513146663	3.171048888	3695.304354	4.8762E-133
Residual	140	0.1201381	0.000858129		
Total	143	9.633284764			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.292784596	0.00984461	29.74059899	2.25193E-62	0.273321274	0.312247919	0.273321274	0.312247919
β1	0.020415818	0.000434457	46.99153447	1.31433E-87	0.019556872	0.021274763	0.019556872	0.021274763
β2	-0.000146385	5.22015E-06	-28.04230529	2.6131E-59	-0.000156706	-0.000136065	-0.000156706	-0.000136065
β3	3.5579E-07	1.70074E-08	20.91972526	6.3186E-45	3.22166E-07	3.89415E-07	3.22166E-07	3.89415E-07

Drilling and Completion Costs for Natural Gas

The 2004 – 2007 JAS data was used to calculate the equation for vertical drilling and completion costs for natural gas. The data was analyzed at a regional level. The independent variable was depth. Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. The method of estimation used was ordinary least squares. The form of the equation is given below.

$$\text{Drilling Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \quad \text{(2.B-2)}$$

where Drilling Cost = DWC_W

β0 = GAS_DWCK

β1 = GAS_DWCA

β2 = GAS_DWCB

β3 = GAS_DWCC

from equations 2-24 and 2-25 in Chapter 2.

Northeast Region:

Regression Statistics	
Multiple R	0.837701882
R Square	0.701744444
Adjusted R Square	0.694887994
Standard Error	1199562.042
Observations	90

ANOVA

	df	SS	MS	F	Significance F
Regression	2	2.94547E+14	1.47274E+14	102.3480792	1.39509E-23
Residual	87	1.25189E+14	1.43895E+12		
Total	89	4.19736E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	197454.5012	290676.607	0.679292714	0.498755704	-380296.7183	775205.7207	-380296.7183	775205.7207
β1	19.31146768	128.263698	0.150560665	0.880670823	-235.6265154	274.2494508	-235.6265154	274.2494508
β2	0.040120878	0.009974857	4.022200679	0.000122494	0.020294769	0.059946987	0.020294769	0.059946987

Gulf Coast Region:

Regression Statistics	
Multiple R	0.842706997
R Square	0.710155083
Adjusted R Square	0.708248209
Standard Error	2573551.438
Observations	307

ANOVA

	df	SS	MS	F	Significance F
Regression	2	4.93318E+15	2.46659E+15	372.4183744	1.77494E-82
Residual	304	2.01344E+15	6.62317E+12		
Total	306	6.94662E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	318882.7578	272026.272	1.172249855	0.242014577	-216410.0169	854175.5325	-216410.0169	854175.5325
β2	0.019032113	0.008289474	2.295937192	0.022359763	0.002720101	0.035344125	0.002720101	0.035344125
β3	1.12638E-06	4.6744E-07	2.409676918	0.016560642	2.06552E-07	2.04621E-06	2.06552E-07	2.04621E-06

Mid-Continent Region:

Regression Statistics	
Multiple R	0.92348831
R Square	0.852830659
Adjusted R Square	0.850494637
Standard Error	1309841.335
Observations	129

ANOVA

	df	SS	MS	F	Significance F
Regression	2	1.25272E+15	6.26359E+14	365.0782904	3.73674E-53
Residual	126	2.16176E+14	1.71568E+12		
Total	128	1.46889E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	355178.8049	240917.4549	1.47427593	0.142901467	-121589.7497	831947.3594	-121589.7497	831947.3594
β1	54.21184769	45.96361807	1.17945127	0.240440741	-36.74880003	145.1724954	-36.74880003	145.1724954
β3	1.20269E-06	1.12352E-07	10.70467954	2.04711E-19	9.80347E-07	1.42503E-06	9.80347E-07	1.42503E-06

Southwest Region:

Regression Statistics	
Multiple R	0.915492169
R Square	0.838125912
Adjusted R Square	0.834866702
Standard Error	1386872.99
Observations	153

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1.48386E+15	4.94618E+14	257.1561693	1.088E-58
Residual	149	2.86589E+14	1.92342E+12		
Total	152	1.77044E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	91618.176	571133.886	0.160414534	0.872771817	-1036949.89	1220186.242	-1036949.89	1220186.242
β1	376.1968481	269.4896391	1.395960339	0.164802951	-156.3182212	908.7119175	-156.3182212	908.7119175
β2	-0.062403125	0.034837969	-1.791238896	0.075284827	-0.131243411	0.00643716	-0.131243411	0.00643716
β3	5.03882E-06	1.29778E-06	3.88265606	0.000154832	2.4744E-06	7.60325E-06	2.4744E-06	7.60325E-06

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.936745489
R Square	0.877492112
Adjusted R Square	0.87539796
Standard Error	2403080.549
Observations	120

ANOVA

	df	SS	MS	F	Significance F
Regression	2	4.83951E+15	2.41976E+15	419.0202716	4.54566E-54
Residual	117	6.75651E+14	5.7748E+12		
Total	119	5.51516E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	219733.2637	346024.9678	0.635021412	0.526654367	-465551.0299	905017.5572	-465551.0299	905017.5572
β2	0.032265399	0.013130355	2.457313594	0.015464796	0.00626142	0.058269377	0.00626142	0.058269377
β3	2.6019E-06	7.88034E-07	3.301759413	0.001274492	1.04124E-06	4.16256E-06	1.04124E-06	4.16256E-06

West Coast Region:

Regression Statistics	
Multiple R	0.901854712
R Square	0.813341922
Adjusted R Square	0.795564962
Standard Error	494573.0787
Observations	24

ANOVA

	df	SS	MS	F	Significance F
Regression	2	2.23824E+13	1.11912E+13	45.75258814	2.21815E-08
Residual	21	5.13665E+12	2.44603E+11		
Total	23	2.75191E+13			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	385532.8938	215673.5911	1.787575808	0.088286514	-62984.89058	834050.6782	-62984.89058	834050.6782
β2	0.01799366	0.016370041	1.099182335	0.284130777	-0.016049704	0.052037025	-0.016049704	0.052037025
β3	1.01127E-06	1.49488E-06	0.676491268	0.506112235	-2.0975E-06	4.12005E-06	-2.0975E-06	4.12005E-06

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.856130745
R Square	0.732959853
Adjusted R Square	0.706255838
Standard Error	2157271.229
Observations	23

ANOVA

	df	SS	MS	F	Significance F
Regression	2	2.55472E+14	1.27736E+14	27.44755272	1.84402E-06
Residual	20	9.30764E+13	4.65382E+12		
Total	22	3.48548E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	267619.9291	1118552.942	0.239255487	0.813342236	-2065640.615	2600880.473	-2065640.615	2600880.473
β1	30.61609506	550.5220307	0.055612843	0.956202055	-1117.752735	1178.984925	-1117.752735	1178.984925
β2	0.049406678	0.035529716	1.390573371	0.179635875	-0.024707012	0.123520367	-0.024707012	0.123520367

Drilling and Completion Cost for Gas - Cost Adjustment Factor

The cost adjustment factor for vertical drilling and completion costs for gas was calculated using JAS data through 2007. The initial cost was normalized at various prices from \$1 to \$20 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$5 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Gas Price} + \beta 2 * \text{Gas Price}^2 + \beta 3 * \text{Gas Price}^3$$

Northeast Region:

Regression Statistics	
Multiple R	0.988234523
R Square	0.976607472
Adjusted R Square	0.976106203
Standard Error	0.03924461
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.001833192	3.000611064	1948.272332	6.4218E-114
Residual	140	0.215619522	0.001540139		
Total	143	9.217452714			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.315932281	0.013188706	23.95476038	2.2494E-51	0.289857502	0.34200706	0.289857502	0.34200706
β1	0.195760743	0.005820373	33.63371152	6.11526E-69	0.184253553	0.207267932	0.184253553	0.207267932
β2	-0.013906425	0.000699337	-19.88514708	1.29788E-42	-0.015289053	-0.012523798	-0.015289053	-0.012523798
β3	0.000336178	2.27846E-05	14.75458424	2.61104E-30	0.000291131	0.000381224	0.000291131	0.000381224

Gulf Coast Region:

Regression Statistics	
Multiple R	0.976776879
R Square	0.954093072
Adjusted R Square	0.953109352
Standard Error	0.051120145
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	7.60369517	2.534565057	969.8828784	1.98947E-93
Residual	140	0.365857688	0.002613269		
Total	143	7.969552858			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.343645899	0.017179647	20.00308313	7.02495E-43	0.309680816	0.377610983	0.309680816	0.377610983
β1	0.190338822	0.007581635	25.10524794	1.08342E-53	0.175349523	0.205328121	0.175349523	0.205328121
β2	-0.013965513	0.000910959	-15.33056399	9.3847E-32	-0.015766527	-0.012164498	-0.015766527	-0.012164498
β3	0.000342962	2.96793E-05	11.55560459	4.15963E-22	0.000284285	0.00040164	0.000284285	0.00040164

Mid-continent Region:

Regression Statistics	
Multiple R	0.973577019
R Square	0.947852212
Adjusted R Square	0.94673476
Standard Error	0.058882142
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.822668656	2.940889552	848.2258794	1.4872E-89
Residual	140	0.485394925	0.003467107		
Total	143	9.308063582			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.309185338	0.019788175	15.62475232	1.738E-32	0.270063053	0.348307623	0.270063053	0.348307623
β1	0.019036286	0.000873282	21.79856116	7.62464E-47	0.017309761	0.020762811	0.017309761	0.020762811
β2	-0.000123667	1.04928E-05	-11.78593913	1.05461E-22	-0.000144412	-0.000102922	-0.000144412	-0.000102922
β3	2.60516E-07	3.41858E-08	7.620611936	3.45556E-12	1.92929E-07	3.28104E-07	1.92929E-07	3.28104E-07

Southwest Region:

Regression Statistics	
Multiple R	0.966438524
R Square	0.934003421
Adjusted R Square	0.932589209
Standard Error	0.06631093
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.712149531	2.904049844	660.4406967	2.13407E-82
Residual	140	0.615599523	0.004397139		
Total	143	9.327749054			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.323862308	0.022284725	14.53292844	9.46565E-30	0.279804211	0.367920404	0.279804211	0.367920404
β1	0.193832047	0.009834582	19.70923084	3.2532E-42	0.174388551	0.213275544	0.174388551	0.213275544
β2	-0.013820723	0.001181658	-11.69604336	1.80171E-22	-0.016156924	-0.011484522	-0.016156924	-0.011484522
β3	0.000334693	3.84988E-05	8.693602923	8.44808E-15	0.000258579	0.000410807	0.000258579	0.000410807

Rocky Mountains Region:

Regression Statistics	
Multiple R	0.985593617
R Square	0.971394777
Adjusted R Square	0.970781808
Standard Error	0.0421446
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.444274294	2.814758098	1584.737059	8.3614E-108
Residual	140	0.248663418	0.001776167		
Total	143	8.692937712			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.32536782	0.014163288	22.97261928	2.42535E-49	0.29736624	0.353369401	0.29736624	0.353369401
β1	0.194045615	0.006250471	31.04496067	1.21348E-64	0.181688099	0.206403131	0.181688099	0.206403131
β2	-0.01396687	0.000751015	-18.59732564	1.18529E-39	-0.015451667	-0.012482073	-0.015451667	-0.012482073
β3	0.000339698	2.44683E-05	13.88318297	4.22503E-28	0.000291323	0.000388073	0.000291323	0.000388073

West Coast Region:

Regression Statistics	
Multiple R	0.994143406
R Square	0.988321112
Adjusted R Square	0.98807085
Standard Error	0.026802603
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.510960152	2.836986717	3949.147599	4.9307E-135
Residual	140	0.100573131	0.00071838		
Total	143	8.611533284			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.325917293	0.009007393	36.18330938	6.29717E-73	0.308109194	0.343725393	0.308109194	0.343725393
β1	0.193657091	0.003975097	48.71757347	1.12458E-89	0.185798111	0.201516072	0.185798111	0.201516072
β2	-0.013893214	0.000477621	-29.08835053	3.2685E-61	-0.014837497	-0.012948932	-0.014837497	-0.012948932
β3	0.000337413	1.5561E-05	21.68318808	1.35414E-46	0.000306648	0.000368178	0.000306648	0.000368178

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.970035104
R Square	0.940968103
Adjusted R Square	0.939703134
Standard Error	0.057035843
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	7.259587116	2.419862372	743.8663996	8.71707E-86
Residual	140	0.455432229	0.003253087		
Total	143	7.715019345			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.352772153	0.0191677	18.40451098	3.34838E-39	0.31487658	0.390667726	0.31487658	0.390667726
β1	0.189510541	0.008458993	22.40344064	3.85701E-48	0.172786658	0.206234423	0.172786658	0.206234423
β2	-0.014060192	0.001016376	-13.83364754	5.65155E-28	-0.016069622	-0.012050761	-0.016069622	-0.012050761
β3	0.000347364	3.31138E-05	10.49000322	2.34854E-19	0.000281896	0.000412832	0.000281896	0.000412832

Drilling and Completion Costs for Dryholes

The 2004 – 2007 JAS data was used to calculate the equation for vertical drilling and completion costs for dryholes. The data was analyzed at a regional level. The independent variable was depth. Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. The method of estimation used was ordinary least squares. The form of the equation is given bellow.

Drilling Cost = β0 + β1 * Depth + β2 * Depth² + β3 * Depth^3 (2.B-3)

where Drilling Cost = DWC_W

β0 = DRY_DWCK

β1 = DRY_DWCA

β2 = DRY_DWCB

β3 = DRY_DWCC

from equations 2-19 and 2-20 in Chapter 2.

Northeast Region:

Regression Statistics	
Multiple R	0.913345218
R Square	0.834199487
Adjusted R Square	0.828851084
Standard Error	1018952.27
Observations	97

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	4.85819E+14	1.6194E+14	155.9716777	3.64706E-36
Residual	93	9.65585E+13	1.03826E+12		
Total	96	5.82378E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	170557.6447	323739.1839	0.526836581	0.599561475	-472323.5706	813438.8601	-472323.5706	813438.8601
β1	256.9930321	233.0025772	1.102962187	0.272889552	-205.7034453	719.6895095	-205.7034453	719.6895095
β2	-0.043428533	0.043117602	-1.007211224	0.31644672	-0.129051459	0.042194394	-0.129051459	0.042194394
β3	5.9031E-06	2.11581E-06	2.789995653	0.006394574	1.70153E-06	1.01047E-05	1.70153E-06	1.01047E-05

Gulf Coast Region:

Regression Statistics	
Multiple R	0.868545327
R Square	0.754370985
Adjusted R Square	0.752096642
Standard Error	2529468.051
Observations	328

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6.36662E+15	2.12221E+15	331.6874692	2.10256E-98
Residual	324	2.07302E+15	6.39821E+12		
Total	327	8.43964E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	118790.7619	515360.6337	0.230500264	0.81784853	-895084.76	1132666.284	-895084.76	1132666.284
β1	126.2333724	241.1698405	0.523421055	0.601039076	-348.2231187	600.6898634	-348.2231187	600.6898634
β2	-0.001057252	0.0294162	-0.035941139	0.971351426	-0.058928115	0.056813612	-0.058928115	0.056813612
β3	2.32104E-06	1.0194E-06	2.276864977	0.02344596	3.15558E-07	4.32653E-06	3.15558E-07	4.32653E-06

Mid-Continent Region:

Regression Statistics	
Multiple R	0.80373002
R Square	0.645981944
Adjusted R Square	0.636056204
Standard Error	904657.9939
Observations	111

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1.59789E+14	5.32631E+13	65.08149035	5.0095E-24
Residual	107	8.75695E+13	8.18406E+11		
Total	110	2.47359E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	163849.8824	309404.7345	0.529564884	0.597510699	-449508.8999	777208.6646	-449508.8999	777208.6646
β1	17.95111978	155.7546455	0.115252548	0.908460959	-290.8142902	326.7165297	-290.8142902	326.7165297
β2	0.022715716	0.021144885	1.074288957	0.285109837	-0.019201551	0.064632983	-0.019201551	0.064632983
β3	-3.50301E-07	7.90957E-07	-0.442882115	0.658745077	-1.91828E-06	1.21768E-06	-1.91828E-06	1.21768E-06

Southwest Region:

Regression Statistics	
Multiple R	0.916003396
R Square	0.839062222
Adjusted R Square	0.835290243
Standard Error	734795.4183
Observations	132

ANOVA

	df	SS	MS	F	Significance F
Regression	3	3.60312E+14	1.20104E+14	222.4461445	1.40193E-50
Residual	128	6.91103E+13	5.39924E+11		
Total	131	4.29423E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	22628.66985	252562.1046	0.089596457	0.928747942	-477108.2352	522365.5749	-477108.2352	522365.5749
β1	262.7649266	164.1391792	1.600866581	0.111871702	-62.01224262	587.5420958	-62.01224262	587.5420958
β2	-0.064989728	0.029352301	-2.21412721	0.02859032	-0.123068227	-0.006911229	-0.123068227	-0.006911229
β3	6.52693E-06	1.49073E-06	4.378340081	2.46095E-05	3.57727E-06	9.4766E-06	3.57727E-06	9.4766E-06

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.908263682
R Square	0.824942917
Adjusted R Square	0.821295894
Standard Error	1868691.311
Observations	99

ANOVA

	df	SS	MS	F	Significance F
Regression	2	1.57976E+15	7.89879E+14	226.1962739	4.70571E-37
Residual	96	3.35233E+14	3.49201E+12		
Total	98	1.91499E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	288056.5506	314517.8483	0.915867103	0.362031526	-336256.4285	912369.5298	-336256.4285	912369.5298
β2	0.018141347	0.017298438	1.048727458	0.296936644	-0.01619578	0.052478474	-0.01619578	0.052478474
β3	3.85847E-06	1.27201E-06	3.033362592	0.003110773	1.33355E-06	6.3834E-06	1.33355E-06	6.3834E-06

West Coast Region:

Regression Statistics	
Multiple R	0.853182771
R Square	0.727920841
Adjusted R Square	0.707514904
Standard Error	907740.218
Observations	44

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.81804E+13	2.93935E+13	35.67201271	2.18647E-11
Residual	40	3.29597E+13	8.23992E+11		
Total	43	1.2114E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	106996.0572	512960.104	0.208585534	0.835830348	-929734.9747	1143727.089	-929734.9747	1143727.089
β1	687.3095347	329.4149478	2.086455212	0.043357214	21.53709715	1353.081972	21.53709715	1353.081972
β2	-0.15898723	0.058188911	-2.732259905	0.009317504	-0.276591406	-0.041383054	-0.276591406	-0.041383054
β3	1.14978E-05	2.91968E-06	3.938046272	0.000320309	5.59694E-06	1.73987E-05	5.59694E-06	1.73987E-05

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.841621294
R Square	0.708326403
Adjusted R Square	0.687977082
Standard Error	2155533.512
Observations	47

ANOVA

	df	SS	MS	F	Significance F
Regression	3	4.85193E+14	1.61731E+14	34.80835607	1.41404E-11
Residual	43	1.99792E+14	4.64632E+12		
Total	46	6.84985E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	122507.9534	1373015.289	0.089225484	0.929317007	-2646441.235	2891457.142	-2646441.235	2891457.142
β1	345.4371452	801.6324436	0.430917122	0.668681154	-1271.20873	1962.08302	-1271.20873	1962.08302
β2	-0.014734575	0.126273194	-0.11668807	0.907650548	-0.269388738	0.239919588	-0.269388738	0.239919588
β3	3.23748E-06	5.69952E-06	0.568026219	0.572971531	-8.2567E-06	1.47317E-05	-8.2567E-06	1.47317E-05

Drilling and Completion Cost for Dry - Cost Adjustment Factor

The cost adjustment factor for vertical drilling and completion costs for dryholes was calculated using JAS data through 2007. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Northeast Region:

Regression Statistics	
Multiple R	0.994846264
R Square	0.989719089
Adjusted R Square	0.989498783
Standard Error	0.026930376
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.774469405	3.258156468	4492.489925	6.5663E-139
Residual	140	0.101534319	0.000725245		
Total	143	9.876003725			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.290689859	0.009050333	32.11924425	1.85582E-66	0.272796865	0.308582854	0.272796865	0.308582854
β1	0.020261651	0.000399405	50.72962235	5.26469E-92	0.019472006	0.021051296	0.019472006	0.021051296
β2	-0.000143294	4.79898E-06	-29.85918012	1.391E-62	-0.000152782	-0.000133806	-0.000152782	-0.000133806
β3	3.45487E-07	1.56352E-08	22.09672004	1.74153E-47	3.14575E-07	3.76399E-07	3.14575E-07	3.76399E-07

Gulf Coast Region:

Regression Statistics	
Multiple R	0.993347128
R Square	0.986738516
Adjusted R Square	0.986454342
Standard Error	0.031666016
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.44539464	3.481798214	3472.296057	3.5967E-131
Residual	140	0.140383119	0.001002737		
Total	143	10.58577776			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.277940175	0.010641812	26.11774938	1.12431E-55	0.256900742	0.298979608	0.256900742	0.298979608
β1	0.020529977	0.000469639	43.71437232	1.71946E-83	0.019601475	0.021458479	0.019601475	0.021458479
β2	-0.000143466	5.64287E-06	-25.42421447	2.53682E-54	-0.000154622	-0.000132309	-0.000154622	-0.000132309
β3	3.43878E-07	1.83846E-08	18.70465533	6.66256E-40	3.07531E-07	3.80226E-07	3.07531E-07	3.80226E-07

Mid-Continent Region:

Regression Statistics	
Multiple R	0.984006541
R Square	0.968268874
Adjusted R Square	0.967588921
Standard Error	0.048034262
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.856909541	3.285636514	1424.023848	1.1869E-104
Residual	140	0.323020652	0.00230729		
Total	143	10.17993019			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.289971748	0.016142592	17.96314638	3.67032E-38	0.258056977	0.32188652	0.258056977	0.32188652
β1	0.020266191	0.000712397	28.44789972	4.71502E-60	0.018857744	0.021674637	0.018857744	0.021674637
β2	-0.000143007	8.55969E-06	-16.70702184	3.8001E-35	-0.00015993	-0.000126084	-0.00015993	-0.000126084
β3	3.44462E-07	2.78877E-08	12.35174476	3.63124E-24	2.89326E-07	3.99597E-07	2.89326E-07	3.99597E-07

Southwest Region:

Regression Statistics	
Multiple R	0.993309425
R Square	0.986663613
Adjusted R Square	0.986377833
Standard Error	0.031536315
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.30103457	3.43367819	3452.531986	5.3348E-131
Residual	140	0.139235479	0.000994539		
Total	143	10.44027005			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.278136296	0.010598224	26.24367047	6.42248E-56	0.257183038	0.299089554	0.257183038	0.299089554
β1	0.020381432	0.000467715	43.57656163	2.59609E-83	0.019456733	0.02130613	0.019456733	0.02130613
β2	-0.00014194	5.61976E-06	-25.25738215	5.41293E-54	-0.000153051	-0.00013083	-0.000153051	-0.00013083
β3	3.38578E-07	1.83093E-08	18.49210412	2.08785E-39	3.0238E-07	3.74777E-07	3.0238E-07	3.74777E-07

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.9949703
R Square	0.9899658
Adjusted R Squar	0.9897508
Standard Error	0.0266287
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.79418782	3.2647293	4604.11	1.199E-139
Residual	140	0.09927263	0.0007091		
Total	143	9.89346045			

	Coefficients	Standard Erro	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.2902761	0.00894897	32.436833	5.504E-67	0.27258355	0.3079687	0.2725836	0.3079687
β1	0.0202676	0.00039493	51.319418	1.133E-92	0.01948684	0.0210484	0.0194868	0.0210484
β2	-0.0001433	4.7452E-06	-30.194046	3.595E-63	-0.0001527	-0.0001339	-0.0001527	-0.0001339
β3	3.454E-07	1.546E-08	22.340389	5.253E-48	3.1482E-07	3.76E-07	3.148E-07	3.76E-07

West Coast Region:

Regression Statistics	
Multiple R	0.992483684
R Square	0.985023864
Adjusted R Square	0.984702946
Standard Error	0.032081124
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.477071064	3.159023688	3069.401798	1.7868E-127
Residual	140	0.144087788	0.001029198		
Total	143	9.621158852			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.297817853	0.010781315	27.62351924	1.55941E-58	0.276502615	0.31913309	0.276502615	0.31913309
β1	0.020092432	0.000475796	42.22913162	1.54864E-81	0.019151759	0.021033105	0.019151759	0.021033105
β2	-0.000142719	5.71684E-06	-24.96465108	2.06229E-53	-0.000154021	-0.000131416	-0.000154021	-0.000131416
β3	3.44906E-07	1.86256E-08	18.51777816	1.81824E-39	3.08082E-07	3.81729E-07	3.08082E-07	3.81729E-07

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.993525621
R Square	0.987093159
Adjusted R Square	0.986816584
Standard Error	0.031179889
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.40915184	3.469717279	3568.986978	5.3943E-132
Residual	140	0.136105966	0.000972185		
Total	143	10.5452578			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.281568556	0.010478442	26.87122338	4.04796E-57	0.260852113	0.302284998	0.260852113	0.302284998
β1	0.020437386	0.000462429	44.19569691	4.11395E-84	0.019523138	0.021351633	0.019523138	0.021351633
β2	-0.000142671	5.55624E-06	-25.67758357	8.07391E-55	-0.000153656	-0.000131686	-0.000153656	-0.000131686
β3	3.42012E-07	1.81024E-08	18.89319503	2.43032E-40	3.06223E-07	3.77802E-07	3.06223E-07	3.77802E-07

Drilling and Completion Costs for Horizontal Wells

The costs of horizontal drilling for crude oil, natural gas, and dryholes are based upon cost estimates developed for the Department of Energy's Comprehensive Oil and Gas Analysis Model. The form of the equation is as follows:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth}^2 + \beta 2 * \text{Depth}^2 * \text{nlat} + \beta 3 * \text{Depth}^2 * \text{nlat} * \text{latlen} \qquad (2.B\text{-}4)$$

Where, nlat is the number of laterals per pattern and latlen is the length of those laterals. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Regression Statistics	
Multiple R	1
R Square	1
Adjusted R Square	1
Standard Error	3.12352E-12
Observations	120

ANOVA

	df	SS	MS	F	Significance F
Regression	3	147,510,801.46	49,170,267.15	5.04E+30	0.00
Residual	116	0.00	0.00		
Total	119	147,510,801.46			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	172.88	4.37E-13	3.95E+14	0.00	172.88	172.88	172.88	172.88
β1	8.07E-06	8.81E-21	9.16E+14	0.00	8.07E-06	8.07E-06	8.07E-06	8.07E-06
β2	1.15E-06	3.20E-21	3.60E+14	0.00	1.15E-06	1.15E-06	1.15E-06	1.15E-06
β3	9.22E-10	1.48E-24	6.23E+14	0.00	9.22E-10	9.22E-10	9.22E-10	9.22E-10

Cost to Equip a Primary Producer

The cost to equip a primary producer was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). The cost to equip a primary producer is equal to the grand total cost minus the producing equipment subtotal. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \quad (2.B\text{-}5)$$

where Cost = NPR_W
β0 = NPRK
β1 = NPRA
β2 = NPRB
β3 = NPRC
from equation 2-21 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS regions 2 and 4:

Regression Statistics	
Multiple R	0.921
R Square	0.849
Adjusted R Square	0.697
Standard Error	621.17
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2,163,010.81	2,163,010.81	5.61	0.254415
Residual	1	385,858.01	385,858.01		
Total	2	2,548,868.81			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	51,315.4034	760.7805	67.4510	0.0094	41,648.8117	60,981.9952	41,648.8117	60,981.9952
β1	0.3404	0.1438	2.3676	0.2544	-1.4864	2.1672	-1.4864	2.1672

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.995
R Square	0.990
Adjusted R Square	0.981
Standard Error	1,193.14
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	145,656,740.81	145,656,740.81	102.32	0.06
Residual	1	1,423,576.87	1,423,576.87		
Total	2	147,080,317.68			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	45,821.717	1,461.289	31.357	0.020	27,254.360	64,389.074	27,254.360	64,389.074
β1	2.793	0.276	10.115	0.063	-0.716	6.302	-0.716	6.302

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9998
R Square	0.9995
Adjusted R Square	0.9990
Standard Error	224.46
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	105,460,601.42	105,460,601.42	2,093.17	0.01
Residual	1	50,383.23	50,383.23		
Total	2	105,510,984.64			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	62,709.378	274.909	228.110	0.003	59,216.346	66,202.411	59,216.346	66,202.411
β1	2.377	0.052	45.751	0.014	1.717	3.037	1.717	3.037

West Coast, applied to OLOGSS regions 6:

Regression Statistics	
Multiple R	0.9095
R Square	0.8272
Adjusted R Square	0.7408
Standard Error	2,257.74
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	48,812,671.60	48,812,671.60	9.58	0.09
Residual	2	10,194,785.98	5,097,392.99		
Total	3	59,007,457.58			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	106,959.788	2,219.144	48.199	0.000	97,411.576	116,508.001	97,411.576	116,508.001
β1	0.910	0.294	3.095	0.090	-0.355	2.174	-0.355	2.174

Cost to Equip a Primary Producer - Cost Adjustment Factor

The cost adjustment factor for the cost to equip a primary producer was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994410537
R Square	0.988852316
Adjusted R Square	0.988613437
Standard Error	0.026443679
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.683975313	2.894658438	4139.554242	1.896E-136
Residual	140	0.097897541	0.000699268		
Total	143	8.781872854			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.31969898	0.008886772	35.97470366	1.30857E-72	0.302129355	0.337268604	0.302129355	0.337268604
β1	0.01951727	0.000392187	49.76527469	6.72079E-91	0.018741896	0.020292644	0.018741896	0.020292644
β2	-0.000139868	4.71225E-06	-29.68181785	2.86084E-62	-0.000149185	-0.000130552	-0.000149185	-0.000130552
β3	3.39583E-07	1.53527E-08	22.11882142	1.56166E-47	3.0923E-07	3.69936E-07	3.0923E-07	3.69936E-07

South Texas, Applied to OLOGSS Regions 2:

Regression Statistics	
Multiple R	0.994238324
R Square	0.988509845
Adjusted R Square	0.988263627
Standard Error	0.026795052
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.647535343	2.882511781	4014.781289	1.5764E-135
Residual	140	0.100516472	0.000717975		
Total	143	8.748051814			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.320349357	0.009004856	35.57517997	5.36201E-72	0.302546274	0.33815244	0.302546274	0.33815244
β1	0.019534419	0.000397398	49.15583863	3.4382E-90	0.018748742	0.020320096	0.018748742	0.020320096
β2	-0.000140302	4.77487E-06	-29.38344709	9.69188E-62	-0.000149742	-0.000130862	-0.000149742	-0.000130862
β3	3.41163E-07	1.55567E-08	21.9303828	3.96368E-47	3.10407E-07	3.7192E-07	3.10407E-07	3.7192E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994150147
R Square	0.988334515
Adjusted R Square	0.98808454
Standard Error	0.026852947
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.552894405	2.850964802	3953.738464	4.5499E-135
Residual	140	0.100951309	0.000721081		
Total	143	8.653845713			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.322462264	0.009024312	35.73261409	3.07114E-72	0.304620715	0.340303814	0.304620715	0.340303814
β1	0.019485751	0.000398256	48.9276546	6.36471E-90	0.018698377	0.020273125	0.018698377	0.020273125
β2	-0.000140187	4.78518E-06	-29.29612329	1.3875E-61	-0.000149648	-0.000130727	-0.000149648	-0.000130727
β3	3.41143E-07	1.55903E-08	21.88177944	5.04366E-47	3.1032E-07	3.71966E-07	3.1032E-07	3.71966E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.99407047
R Square	0.988176099
Adjusted R Square	0.98792273
Standard Error	0.026915882
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.476544403	2.825514801	3900.141282	1.1696E-134
Residual	140	0.101425062	0.000724465		
Total	143	8.577969465			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.324216701	0.009045462	35.84302113	2.08007E-72	0.306333337	0.342100066	0.306333337	0.342100066
β1	0.019446254	0.00039919	48.71430741	1.1346E-89	0.018657034	0.020235473	0.018657034	0.020235473
β2	-0.000140099	4.7964E-06	-29.20929598	1.98384E-61	-0.000149582	-0.000130617	-0.000149582	-0.000130617
β3	3.41157E-07	1.56268E-08	21.8315363	6.47229E-47	3.10262E-07	3.72052E-07	3.10262E-07	3.72052E-07

West Coast, Applied to OLOGSS Regions 6:

Regression Statistics	
Multiple R	0.994533252
R Square	0.98909639
Adjusted R Square	0.988862741
Standard Error	0.026511278
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.92601569	2.975338563	4233.261276	4.0262E-137
Residual	140	0.098398698	0.000702848		
Total	143	9.024414388			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.314154129	0.008909489	35.26062149	1.64245E-71	0.296539591	0.331768668	0.296539591	0.331768668
β1	0.019671366	0.000393189	50.03029541	3.32321E-91	0.01889401	0.020448722	0.01889401	0.020448722
β2	-0.000140565	4.7243E-06	-29.75371308	2.13494E-62	-0.000149906	-0.000131225	-0.000149906	-0.000131225
β3	3.40966E-07	1.53919E-08	22.15229024	1.32417E-47	3.10535E-07	3.71397E-07	3.10535E-07	3.71397E-07

Primary Workover Costs

Primary workover costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Workover costs consist of the total of workover rig services, remedial services, equipment repair and other costs. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \quad (2.B\text{-}6)$$

where Cost = WRK_W

β0 = WRKK

β1 = WRKA

β2 = WRKB

β3 = WRKC

from equation 2-22 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.9839
R Square	0.9681
Adjusted R Square	0.9363
Standard Error	1,034.20
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	32,508,694.98	32,508,694.98	30.39	0.11
Residual	1	1,069,571.02	1,069,571.02		
Total	2	33,578,265.99			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	1,736.081	1,266.632	1.371	0.401	-14,357.935	17,830.097	-14,357.935	17,830.097
β1	1.320	0.239	5.513	0.114	-1.722	4.361	-1.722	4.361

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.7558
R Square	0.5713
Adjusted R Square	0.4284
Standard Error	978.19
Observations	5

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3,824,956.55	3,824,956.55	4.00	0.14
Residual	3	2,870,570.06	956,856.69		
Total	4	6,695,526.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	1,949.479	1,043.913	1.867	0.159	-1,372.720	5,271.678	-1,372.720	5,271.678
β1	0.364	0.182	1.999	0.139	-0.216	0.945	-0.216	0.945

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.9762
R Square	0.9530
Adjusted R Square	0.9060
Standard Error	2,405.79
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	117,342,912.53	117,342,912.53	20.27	0.14
Residual	1	5,787,839.96	5,787,839.96		
Total	2	123,130,752.49			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-2,738.051	2,946.483	-0.929	0.523	-40,176.502	34,700.400	-40,176.502	34,700.400
β1	2.507	0.557	4.503	0.139	-4.568	9.582	-4.568	9.582

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.9898
R Square	0.9798
Adjusted R Square	0.9595
Standard Error	747.71
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	27,074,389.00	27,074,389.00	48.43	0.09
Residual	1	559,069.20	559,069.20		
Total	2	27,633,458.19			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	389.821	915.753	0.426	0.744	-11,245.876	12,025.518	-11,245.876	12,025.518
β1	1.204	0.173	6.959	0.091	-0.995	3.403	-0.995	3.403

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.9985
R Square	0.9969
Adjusted R Square	0.9939
Standard Error	273.2
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	24,387,852.65	24,387,852.65	326.67	0.04
Residual	1	74,656.68	74,656.68		
Total	2	24,462,509.32			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	1,326.648	334.642	3.964	0.157	-2,925.359	5,578.654	-2,925.359	5,578.654
β1	1.143	0.063	18.074	0.035	0.339	1.947	0.339	1.947

Primary Workover Costs - Cost Adjustment Factor

The cost adjustment factor for primary workover costs was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994400682
R Square	0.988832717
Adjusted R Square	0.988593418
Standard Error	0.02694729
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.001886791	3.00062893	4132.207262	2.1441E-136
Residual	140	0.101661902	0.000726156		
Total	143	9.103548693			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.312539579	0.009056017	34.51181296	2.43715E-70	0.294635346	0.330443812	0.294635346	0.330443812
β1	0.019707131	0.000399656	49.31028624	2.26953E-90	0.018916991	0.020497272	0.018916991	0.020497272
β2	-0.000140623	4.802E-06	-29.28428914	1.45673E-61	-0.000150117	-0.000131129	-0.000150117	-0.000131129
β3	3.40873E-07	1.5645E-08	21.78791181	8.03921E-47	3.09942E-07	3.71804E-07	3.09942E-07	3.71804E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994469633
R Square	0.98896985
Adjusted R Square	0.98873349
Standard Error	0.026569939
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.861572267	2.953857422	4184.161269	9.0291E-137
Residual	140	0.098834632	0.000705962		
Total	143	8.960406899			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.315903453	0.008929203	35.37868321	1.07799E-71	0.298249938	0.333556967	0.298249938	0.333556967
β1	0.019629392	0.000394059	49.81332121	5.91373E-91	0.018850316	0.020408468	0.018850316	0.020408468
β2	-0.000140391	4.73475E-06	-29.65123432	3.24065E-62	-0.000149752	-0.00013103	-0.000149752	-0.00013103
β3	3.40702E-07	1.5426E-08	22.08625878	1.83379E-47	3.10204E-07	3.712E-07	3.10204E-07	3.712E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994481853
R Square	0.988994155
Adjusted R Square	0.988758316
Standard Error	0.026752366
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.003736634	3.001245545	4193.504662	7.7373E-137
Residual	140	0.100196473	0.000715689		
Total	143	9.103933107			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.312750341	0.00899051	34.78671677	9.00562E-71	0.294975619	0.330525063	0.294975619	0.330525063
β1	0.019699787	0.000396765	49.6510621	9.11345E-91	0.018915362	0.020484212	0.018915362	0.020484212
β2	-0.000140541	4.76726E-06	-29.480463	6.51147E-62	-0.000149966	-0.000131116	-0.000149966	-0.000131116
β3	3.40661E-07	1.55319E-08	21.93302302	3.91217E-47	3.09954E-07	3.71368E-07	3.09954E-07	3.71368E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.949969362
R Square	0.902441789
Adjusted R Square	0.900351256
Standard Error	0.090634678
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.63829925	3.546099748	431.6802228	1.59892E-70
Residual	140	1.150050289	0.008214645		
Total	143	11.78834953			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.281549378	0.030459064	9.243533578	3.55063E-16	0.221330174	0.341768582	0.221330174	0.341768582
β1	0.020360006	0.001344204	15.14651492	2.70699E-31	0.017702443	0.02301757	0.017702443	0.02301757
β2	-0.000140998	1.61511E-05	-8.729925387	6.86299E-15	-0.000172929	-0.000109066	-0.000172929	-0.000109066
β3	3.36972E-07	5.26206E-08	6.403797584	2.14112E-09	2.32938E-07	4.41006E-07	2.32938E-07	4.41006E-07

West Coast, Applied to OLOGSS Regions 6:

Regression Statistics	
Multiple R	0.994382746
R Square	0.988797046
Adjusted R Square	0.988556983
Standard Error	0.026729324
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.828330392	2.942776797	4118.9013	2.6803E-136
Residual	140	0.100023944	0.000714457		
Total	143	8.928354335			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.316566704	0.008982767	35.24155917	1.75819E-71	0.298807292	0.334326116	0.298807292	0.334326116
β1	0.019613748	0.000396423	49.47682536	1.45204E-90	0.018829998	0.020397497	0.018829998	0.020397497
β2	-0.000140368	4.76315E-06	-29.46957335	6.80842E-62	-0.000149785	-0.000130951	-0.000149785	-0.000130951
β3	3.40752E-07	1.55185E-08	21.95777375	3.46083E-47	3.10071E-07	3.71433E-07	3.10071E-07	3.71433E-07

Cost to Convert a Primary to Secondary Well

The cost to convert a primary to secondary well was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Conversion costs for a primary to a secondary well consist of pumping equipment, rods and pumps, and supply wells. The data was analyzed on a regional level. The secondary operations costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \qquad (2.B\text{-}7)$$

where Cost = PSW_W

β0 = PSWK

β1 = PSWA

β2 = PSWB

β3 = PSWC

from equation 2-35 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.999208
R Square	0.998416
Adjusted R Square	0.996832
Standard Error	9968.98
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	62,643,414,406.49	62,643,414,406.49	630.34	0.03
Residual	1	99,380,639.94	99,380,639.94		
Total	2	62,742,795,046.43			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-115.557	12,209.462	-0.009	0.994	-155,250.815	155,019.701	-155,250.815	155,019.701
β1	57.930	2.307	25.107	0.025	28.612	87.248	28.612	87.248

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.996760
R Square	0.993531
Adjusted R Square	0.991914
Standard Error	16909.05
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	175,651,490,230.16	175,651,490,230.16	614.35	0.00
Residual	4	1,143,664,392.16	285,916,098.04		
Total	5	176,795,154,622.33			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-10,733.7	14,643.670	-0.733	0.504	-51,391.169	29,923.692	-51,391.169	29,923.692
β1	68.593	2.767	24.786	0.000	60.909	76.276	60.909	76.276

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.999830
R Square	0.999660
Adjusted R Square	0.999320
Standard Error	4047.64
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	48,164,743,341	48,164,743,341	2,939.86	0.01
Residual	1	16,383,350	16,383,350		
Total	2	48,181,126,691			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-32,919.3	4,957.320	-6.641	0.095	-95,907.768	30,069.148	-95,907.768	30,069.148
β1	50.796	0.937	54.220	0.012	38.893	62.700	38.893	62.700

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	1.00000
R Square	0.99999
Adjusted R Square	0.99999
Standard Error	552.23
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	44,056,261,873.48	44,056,261,873.48	144,469.3	0.00
Residual	1	304,952.52	304,952.52		
Total	2	44,056,566,825.99			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	-25,175.8	676.335	-37.224	0.017	-33,769.389	-16,582.166	-33,769.389	-16,582.166
β1	48.581	0.128	380.091	0.002	46.957	50.205	46.957	50.205

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.999970
R Square	0.999941
Adjusted R Square	0.999882
Standard Error	2317.03
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	90,641,249,203.56	90,641,249,203.56	16,883.5	0.00
Residual	1	5,368,613.99	5,368,613.99		
Total	2	90,646,617,817.55			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	-47,775.5	2,837.767	-16.836	0.038	-83,832.597	-11,718.412	-83,832.597	-11,718.412
β1	69.683	0.536	129.937	0.005	62.869	76.498	62.869	76.498

Cost to Convert a Primary to Secondary Well - Cost Adjustment Factor

The cost adjustment factor for the cost to convert a primary to secondary well was calculated using data through 2008 from the Cost and Indices data base provided EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994210954
R Square	0.988455421
Adjusted R Square	0.988208037
Standard Error	0.032636269
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.7675639	4.255854635	3995.634681	2.1943E-135
Residual	140	0.149117649	0.001065126		
Total	143	12.91668155			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.386844292	0.010967879	35.27065592	1.58464E-71	0.365160206	0.408528378	0.365160206	0.408528378
β1	0.023681158	0.000484029	48.92509151	6.40898E-90	0.022724207	0.024638109	0.022724207	0.024638109
β2	-0.000169861	5.81577E-06	-29.207048	2.00231E-61	-0.00018136	-0.000158363	-0.00018136	-0.000158363
β3	4.12786E-07	1.89479E-08	21.78527316	8.14539E-47	3.75325E-07	4.50247E-07	3.75325E-07	4.50247E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.965088368
R Square	0.931395559
Adjusted R Square	0.929925464
Standard Error	0.077579302
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	11.43935934	3.813119781	633.5614039	3.21194E-81
Residual	140	0.842596733	0.006018548		
Total	143	12.28195608			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.403458143	0.02607162	15.4749932	4.09637E-32	0.351913151	0.455003136	0.351913151	0.455003136
β1	0.023030837	0.00115058	20.01672737	6.5441E-43	0.02075608	0.025305595	0.02075608	0.025305595
β2	-0.000167719	1.38246E-05	-12.13194348	1.34316E-23	-0.000195051	-0.000140387	-0.000195051	-0.000140387
β3	4.10451E-07	4.5041E-08	9.112847285	7.57277E-16	3.21403E-07	4.995E-07	3.21403E-07	4.995E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.930983781
R Square	0.866730801
Adjusted R Square	0.863875032
Standard Error	0.115716747
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.19199867	4.063999556	303.5017657	4.7623E-61
Residual	140	1.874651162	0.013390365		
Total	143	14.06664983			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.39376891	0.038888247	10.12565341	2.02535E-18	0.316884758	0.470653063	0.316884758	0.470653063
β1	0.023409924	0.001716196	13.6405849	1.759E-27	0.020016911	0.026802936	0.020016911	0.026802936
β2	-0.000169013	2.06207E-05	-8.196307608	1.41642E-13	-0.000209782	-0.000128245	-0.000209782	-0.000128245
β3	4.11972E-07	6.71828E-08	6.132113904	8.35519E-09	2.79148E-07	5.44796E-07	2.79148E-07	5.44796E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.930623851
R Square	0.866060752
Adjusted R Square	0.863190626
Standard Error	0.117705607
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.5418858	4.180628599	301.7500036	6.76263E-61
Residual	140	1.939645392	0.01385461		
Total	143	14.48153119			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.363067907	0.039556632	9.178433366	5.17966E-16	0.284862323	0.441273492	0.284862323	0.441273492
β1	0.024133277	0.001745693	13.82446554	5.96478E-28	0.020681947	0.027584606	0.020681947	0.027584606
β2	-0.000175479	2.09751E-05	-8.366057262	5.44112E-14	-0.000216948	-0.00013401	-0.000216948	-0.00013401
β3	4.28328E-07	6.83375E-08	6.267838182	4.24825E-09	2.93221E-07	5.63435E-07	2.93221E-07	5.63435E-07

West Coast, Applied to OLOGSS Regions 6:

Regression Statistics	
Multiple R	0.930187107
R Square	0.865248054
Adjusted R Square	0.862360512
Standard Error	0.116469162
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.19426209	4.06475403	299.6486777	1.03233E-60
Residual	140	1.899109212	0.013565066		
Total	143	14.0933713			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.393797507	0.039141107	10.06097011	2.96602E-18	0.316413437	0.471181577	0.316413437	0.471181577
β1	0.023409194	0.001727356	13.55204156	2.96327E-27	0.01999412	0.026824269	0.01999412	0.026824269
β2	-0.000168995	2.07548E-05	-8.142483197	1.91588E-13	-0.000210029	-0.000127962	-0.000210029	-0.000127962
β3	4.11911E-07	6.76196E-08	6.091589926	1.02095E-08	2.78223E-07	5.45599E-07	2.78223E-07	5.45599E-07

Cost to Convert a Producer to an Injector

The cost to convert a production well to an injection well was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Conversion costs for a production to an injection well consist of tubing replacement, distribution lines and header costs. The data was analyzed on a regional level. The secondary operation costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}8)$$

where Cost = PSI_W

β0 = PSIK

β1 = PSIA

β2 = PSIB

β3 = PSIC

from equation 2-36 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.994714
R Square	0.989456
Adjusted R Square	0.978913
Standard Error	3204.94
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	963,939,802.16	963,939,802.16	93.84	0.07
Residual	1	10,271,635.04	10,271,635.04		
Total	2	974,211,437.20			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	11,129.3	3,925.233	2.835	0.216	-38,745.259	61,003.937	-38,745.259	61,003.937
β1	7.186	0.742	9.687	0.065	-2.239	16.611	-2.239	16.611

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.988716
R Square	0.977560
Adjusted R Square	0.971950
Standard Error	4435.41
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3,428,080,322.21	3,428,080,322.21	174.25	0.00
Residual	4	78,691,571.93	19,672,892.98		
Total	5	3,506,771,894.14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	24,640.6	3,841.181	6.415	0.003	13,975.763	35,305.462	13,975.763	35,305.462
β1	9.582	0.726	13.201	0.000	7.567	11.598	7.567	11.598

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.993556
R Square	0.987154
Adjusted R Square	0.974307
Standard Error	3770.13
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,092,230,257.01	1,092,230,257.01	76.84	0.07
Residual	1	14,213,917.83	14,213,917.83		
Total	2	1,106,444,174.85			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	9,356.411	4,617.453	2.026	0.292	-49,313.648	68,026.469	-49,313.648	68,026.469
β1	7.649	0.873	8.766	0.072	-3.438	18.737	-3.438	18.737

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.995436
R Square	0.990893
Adjusted R Square	0.981785
Standard Error	3266.39
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	1,160,837,008.65	1,160,837,008.65	108.80	0.06
Residual	1	10,669,310.85	10,669,310.85		
Total	2	1,171,506,319.50			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	24,054.311	4,000.496	6.013	0.105	-26,776.589	74,885.211	-26,776.589	74,885.211
β1	7.886	0.756	10.431	0.061	-1.720	17.492	-1.720	17.492

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.998023
R Square	0.996050
Adjusted R Square	0.992100
Standard Error	2903.09
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	2,125,305,559.02	2,125,305,559.02	252.17	0.04
Residual	1	8,427,914.12	8,427,914.12		
Total	2	2,133,733,473.15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	11,125.846	3,555.541	3.129	0.197	-34,051.391	56,303.083	-34,051.391	56,303.083
β1	10.670	0.672	15.880	0.040	2.133	19.208	2.133	19.208

Cost to Convert a Producer to an Injector - Cost Adjustment Factor

The cost adjustment factor for the cost to convert a producer to an injector was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.99432304
R Square	0.988678308
Adjusted R Square	0.9884357
Standard Error	0.026700062
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.715578807	2.905192936	4075.214275	5.6063E-136
Residual	140	0.099805061	0.000712893		
Total	143	8.815383869			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.318906241	0.008972933	35.54091476	6.05506E-72	0.301166271	0.336646211	0.301166271	0.336646211
β1	0.019564167	0.000395989	49.40584281	1.75621E-90	0.018781276	0.020347059	0.018781276	0.020347059
β2	-0.000140323	4.75794E-06	-29.49235038	6.20216E-62	-0.00014973	-0.000130916	-0.00014973	-0.000130916
β3	3.40991E-07	1.55015E-08	21.9972576	2.84657E-47	3.10343E-07	3.71638E-07	3.10343E-07	3.71638E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994644466
R Square	0.989317613
Adjusted R Square	0.989088705
Standard Error	0.025871111
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.678119686	2.892706562	4321.895164	9.5896E-138
Residual	140	0.093704013	0.000669314		
Total	143	8.771823699			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.316208692	0.008694352	36.36943685	3.2883E-73	0.299019491	0.333397893	0.299019491	0.333397893
β1	0.01974618	0.000383695	51.46325116	7.80746E-93	0.018987594	0.020504765	0.018987594	0.020504765
β2	-0.000142963	4.61022E-06	-31.00997536	1.39298E-64	-0.000152077	-0.000133848	-0.000152077	-0.000133848
β3	3.4991E-07	1.50202E-08	23.29589312	5.12956E-50	3.20214E-07	3.79606E-07	3.20214E-07	3.79606E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994321224
R Square	0.988674696
Adjusted R Square	0.988432011
Standard Error	0.026701262
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.713550392	2.904516797	4073.899599	5.7329E-136
Residual	140	0.099814034	0.000712957		
Total	143	8.813364425			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.318954549	0.008973336	35.54470092	5.97425E-72	0.301213782	0.336695317	0.301213782	0.336695317
β1	0.019563077	0.000396007	49.40087012	1.77978E-90	0.018780151	0.020346004	0.018780151	0.020346004
β2	-0.000140319	4.75815E-06	-29.49027089	6.25518E-62	-0.000149726	-0.000130912	-0.000149726	-0.000130912
β3	3.40985E-07	1.55022E-08	21.99592439	2.8654E-47	3.10337E-07	3.71634E-07	3.10337E-07	3.71634E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.994322163
R Square	0.988676564
Adjusted R Square	0.988433919
Standard Error	0.026700311
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.714383869	2.904794623	4074.579587	5.667E-136
Residual	140	0.099806922	0.000712907		
Total	143	8.814190792			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.318944377	0.008973016	35.54483358	5.97144E-72	0.301204242	0.336684512	0.301204242	0.336684512
β1	0.019563226	0.000395993	49.40300666	1.76961E-90	0.018780328	0.020346125	0.018780328	0.020346125
β2	-0.000140317	4.75798E-06	-29.49085218	6.24031E-62	-0.000149724	-0.00013091	-0.000149724	-0.00013091
β3	3.40976E-07	1.55017E-08	21.99610109	2.8629E-47	3.10328E-07	3.71624E-07	3.10328E-07	3.71624E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.994041278
R Square	0.988118061
Adjusted R Square	0.987863448
Standard Error	0.027307293
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.681741816	2.893913939	3880.863048	1.6477E-134
Residual	140	0.104396354	0.000745688		
Total	143	8.78613817			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.31978359	0.009177001	34.84619603	7.26644E-71	0.301640166	0.337927015	0.301640166	0.337927015
β1	0.019531533	0.000404995	48.22662865	4.2897E-89	0.018730837	0.02033223	0.018730837	0.02033223
β2	-0.000140299	4.86615E-06	-28.83170535	9.47626E-61	-0.00014992	-0.000130679	-0.00014992	-0.000130679
β3	3.41616E-07	1.58541E-08	21.54755837	2.66581E-46	3.10272E-07	3.7296E-07	3.10272E-07	3.7296E-07

Facilities Upgrade Costs for Crude Oil Wells

The facilities upgrading cost for secondary oil wells was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Facilities costs for a secondary oil well consist of plant costs and electrical costs. The data was analyzed on a regional level. The secondary operation costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}9)$$

where Cost = FAC_W

β0 = FACUPK

β1 = FACUPA

β2 = FACUPB

β3 = FACUPC

from equation 2-23 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.947660
R Square	0.898060
Adjusted R Square	0.796120
Standard Error	6332.38
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	353,260,332.81	353,260,332.81	8.81	0.21
Residual	1	40,099,063.51	40,099,063.51		
Total	2	393,359,396.32			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	20,711.761	7,755.553	2.671	0.228	-77,831.455	119,254.977	-77,831.455	119,254.977
β1	4.350	1.466	2.968	0.207	-14.273	22.973	-14.273	22.973

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.942744
R Square	0.888767
Adjusted R Square	0.851689
Standard Error	6699.62
Observations	5

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,075,905,796.72	1,075,905,796.72	23.97	0.02
Residual	3	134,654,629.89	44,884,876.63		
Total	4	1,210,560,426.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	33,665.6	7,149.747	4.709	0.018	10,911.921	56,419.338	10,911.921	56,419.338
β1	6.112	1.248	4.896	0.016	2.139	10.085	2.139	10.085

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.950784
R Square	0.903990
Adjusted R Square	0.807980
Standard Error	6705.31
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	423,335,427.35	423,335,427.35	9.42	0.20
Residual	1	44,961,183.70	44,961,183.70		
Total	2	468,296,611.04			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	19,032.550	8,212.294	2.318	0.259	-85,314.094	123,379.194	-85,314.094	123,379.194
β1	4.762	1.552	3.068	0.201	-14.957	24.482	-14.957	24.482

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.90132
R Square	0.81238
Adjusted R Square	0.62476
Standard Error	8,531
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	315,132,483.91	315,132,483.91	4.33	0.29
Residual	1	72,780,134.04	72,780,134.04		
Total	2	387,912,617.95			

	Coefficient:	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	37,322	10,448.454	3.572	0.174	-95,437.589	170,081.677	-95,437.589	170,081.677
β1	4.109	1.975	2.081	0.285	-20.980	29.198	-20.980	29.198

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.974616
R Square	0.949876
Adjusted R Square	0.899753
Standard Error	6,765.5
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	867,401,274.79	867,401,274.79	18.95	0.14
Residual	1	45,771,551.83	45,771,551.83		
Total	2	913,172,826.62			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	23,746.6	8,285.972	2.866	0.214	-81,536.251	129,029.354	-81,536.251	129,029.354
β1	6.817	1.566	4.353	0.144	-13.080	26.713	-13.080	26.713

Facilities Upgrade Costs for Oil Wells - Cost Adjustment Factor

The cost adjustment factor for facilities upgrade costs for oil wells was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994217662
R Square	0.988468759
Adjusted R Square	0.988221661
Standard Error	0.026793237
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.615198936	2.871732979	4000.310244	2.0238E-135
Residual	140	0.100502859	0.000717878		
Total	143	8.715701795			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.321111529	0.009004246	35.66223488	3.93903E-72	0.303309651	0.338913406	0.303309651	0.338913406
β1	0.019515262	0.000397371	49.11095778	3.88014E-90	0.018729638	0.020300885	0.018729638	0.020300885
β2	-0.00014023	4.77454E-06	-29.37035185	1.02272E-61	-0.00014967	-0.00013079	-0.00014967	-0.00013079
β3	3.4105E-07	1.55556E-08	21.92459665	4.07897E-47	3.10296E-07	3.71805E-07	3.10296E-07	3.71805E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994217643
R Square	0.988468723
Adjusted R Square	0.988221624
Standard Error	0.026793755
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.615504692	2.871834897	4000.297521	2.0242E-135
Residual	140	0.100506746	0.000717905		
Total	143	8.716011438			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.321091731	0.00900442	35.65934676	3.9795E-72	0.30328951	0.338893953	0.30328951	0.338893953
β1	0.019515756	0.000397379	49.11125155	3.87707E-90	0.018730117	0.020301395	0.018730117	0.020301395
β2	-0.000140234	4.77464E-06	-29.37065243	1.02145E-61	-0.000149674	-0.000130794	-0.000149674	-0.000130794
β3	3.41061E-07	1.55559E-08	21.92486379	4.07357E-47	3.10306E-07	3.71816E-07	3.10306E-07	3.71816E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994881087
R Square	0.989788377
Adjusted R Square	0.989569556
Standard Error	0.025598703
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.892246941	2.964082314	4523.289171	4.0903E-139
Residual	140	0.0917411	0.000655294		
Total	143	8.983988041			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.305413562	0.008602806	35.50162345	6.96151E-72	0.288405354	0.32242177	0.288405354	0.32242177
β1	0.019922983	0.000379655	52.47659224	5.82045E-94	0.019172385	0.020673581	0.019172385	0.020673581
β2	-0.000143398	4.56168E-06	-31.43544891	2.62249E-65	-0.000152417	-0.00013438	-0.000152417	-0.00013438
β3	3.48664E-07	1.48621E-08	23.45993713	2.3433E-50	3.1928E-07	3.78047E-07	3.1928E-07	3.78047E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994218671
R Square	0.988470767
Adjusted R Square	0.988223712
Standard Error	0.026793398
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.616820316	2.872273439	4001.015021	1.9993E-135
Residual	140	0.100504067	0.000717886		
Total	143	8.717324383			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.32105584	0.0090043	35.65583598	4.02926E-72	0.303253856	0.338857825	0.303253856	0.338857825
β1	0.019516684	0.000397373	49.11424236	3.84594E-90	0.018731056	0.020302312	0.018731056	0.020302312
β2	-0.00014024	4.77457E-06	-29.37236101	1.01431E-61	-0.00014968	-0.000130801	-0.00014968	-0.000130801
β3	3.4108E-07	1.55557E-08	21.92639924	4.0427E-47	3.10326E-07	3.71835E-07	3.10326E-07	3.71835E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.994682968
R Square	0.989394207
Adjusted R Square	0.98916694
Standard Error	0.025883453
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.749810675	2.916603558	4353.444193	5.7951E-138
Residual	140	0.093793438	0.000669953		
Total	143	8.843604113			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.320979436	0.0086985	36.90055074	5.22609E-74	0.303782034	0.338176837	0.303782034	0.338176837
β1	0.019117244	0.000383878	49.80033838	6.12166E-91	0.018358297	0.019876191	0.018358297	0.019876191
β2	-0.000134273	4.61242E-06	-29.11109331	2.97526E-61	-0.000143392	-0.000125154	-0.000143392	-0.000125154
β3	3.21003E-07	1.50274E-08	21.36117616	6.78747E-46	2.91293E-07	3.50713E-07	2.91293E-07	3.50713E-07

Natural Gas Well Facilities Costs

Natural gas well facilities costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Well facilities costs consist of flowlines and connections, production package costs, and storage tank costs. The data was analyzed on a regional level. The independent variables are depth and Q, which is the flow rate of natural gas in million cubic feet. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Q + \beta3 * Depth * Q \qquad (2.B\text{-}10)$$

where
Cost = FWC_W
β0 = FACGK
β1 = FACGA
β2 = FACGB
β3 = FACGC
Q = PEAKDAILY_RATE
from equation 2-28 in Chapter 2.

Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9834
R Square	0.9672
Adjusted R Square	0.9562
Standard Error	5,820.26
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8,982,542,532.41	2,994,180,844.14	88.39	0.00
Residual	9	304,879,039.45	33,875,448.83		
Total	12	9,287,421,571.86			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,477.41	4,694.03	0.74	0.48	-7,141.24	14,096.05	-7,141.24	14,096.05
β1	5.04	0.40	12.51	0.00	4.13	5.95	4.13	5.95
β2	63.87	19.07	3.35	0.01	20.72	107.02	20.72	107.02
β3	0.00	0.00	-3.18	0.01	-0.01	0.00	-0.01	0.00

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.9621
R Square	0.9256
Adjusted R Square	0.9139
Standard Error	8,279.60
Observations	23

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	16,213,052,116.02	5,404,350,705.34	78.84	0.00
Residual	19	1,302,484,315.70	68,551,806.09		
Total	22	17,515,536,431.72			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	14,960.60	4,066.98	3.68	0.00	6,448.31	23,472.90	6,448.31	23,472.90
β1	4.87	0.47	10.34	0.00	3.88	5.85	3.88	5.85
β2	28.49	6.42	4.43	0.00	15.04	41.93	15.04	41.93
β3	0.00	0.00	-3.62	0.00	0.00	0.00	0.00	0.00

Mid-Continent, applied to OLOGSS regions 3 and 6:

Regression Statistics	
Multiple R	0.9917
R Square	0.9835
Adjusted R Square	0.9765
Standard Error	4,030.43
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6,796,663,629.62	2,265,554,543.21	139.47	0.00
Residual	7	113,710,456.60	16,244,350.94		
Total	10	6,910,374,086.22			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	10,185.92	3,441.41	2.96	0.02	2,048.29	18,323.54	2,048.29	18,323.54
β1	4.51	0.29	15.71	0.00	3.83	5.18	3.83	5.18
β2	55.38	14.05	3.94	0.01	22.16	88.60	22.16	88.60
β3	0.00	0.00	-3.78	0.01	-0.01	0.00	-0.01	0.00

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9594
R Square	0.9204
Adjusted R Square	0.8806
Standard Error	7,894.95
Observations	10

ANOVA

	df	SS	MS	F	Significance F
Regression	3	4,322,988,996.06	1,440,996,332.02	23.12	0.00
Residual	6	373,981,660.54	62,330,276.76		
Total	9	4,696,970,656.60			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	7,922.48	8,200.06	0.97	0.37	-12,142.36	27,987.31	-12,142.36	27,987.31
β1	6.51	1.14	5.71	0.00	3.72	9.30	3.72	9.30
β2	89.26	28.88	3.09	0.02	18.59	159.94	18.59	159.94
β3	-0.01	0.00	-2.77	0.03	-0.01	0.00	-0.01	0.00

Gas Well Facilities Costs - Cost Adjustment Factor

The cost adjustment factor for gas well facilities cost was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $1 to $20 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $5 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Gas Price} + \beta2 * \text{Gas Price}^2 + \beta3 * \text{Gas Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.995733794
R Square	0.991485789
Adjusted R Square	0.991303341
Standard Error	0.025214281
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.3648558	3.454951933	5434.365566	1.2179E-144
Residual	140	0.089006392	0.00063576		
Total	143	10.45386219			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.276309237	0.008473615	32.60818851	2.86747E-67	0.259556445	0.293062029	0.259556445	0.293062029
β1	0.20599743	0.003739533	55.08640551	8.89871E-97	0.198604173	0.213390688	0.198604173	0.213390688
β2	-0.014457925	0.000449317	-32.17753015	1.48375E-66	-0.015346249	-0.0135696	-0.015346249	-0.0135696
β3	0.000347281	1.46389E-05	23.72318475	6.71084E-51	0.000318339	0.000376223	0.000318339	0.000376223

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.99551629
R Square	0.991052684
Adjusted R Square	0.990860956
Standard Error	0.025683748
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.22936837	3.409789455	5169.05027	3.9254E-143
Residual	140	0.092351689	0.000659655		
Total	143	10.32172006			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.280854163	0.008631386	32.5387085	3.73403E-67	0.263789449	0.297918878	0.263789449	0.297918878
β1	0.204879431	0.00380916	53.78599024	2.17161E-95	0.197348518	0.212410345	0.197348518	0.212410345
β2	-0.014391989	0.000457683	-31.44530093	2.52353E-65	-0.015296854	-0.013487125	-0.015296854	-0.013487125
β3	0.000345909	1.49115E-05	23.19753012	8.21832E-50	0.000316428	0.00037539	0.000316428	0.00037539

Mid-Continent, Applied to OLOGSS Regions 3 and 6:

Regression Statistics	
Multiple R	0.995511275
R Square	0.991042698
Adjusted R Square	0.990850756
Standard Error	0.025690919
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.22356717	3.407855722	5163.235345	4.2442E-143
Residual	140	0.092403264	0.000660023		
Total	143	10.31597043			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.280965064	0.008633796	32.5424714	3.68097E-67	0.263895586	0.298034543	0.263895586	0.298034543
β1	0.204856879	0.003810223	53.7650588	2.28751E-95	0.197323863	0.212389895	0.197323863	0.212389895
β2	-0.014391983	0.000457811	-31.43650889	2.61165E-65	-0.0152971	-0.013486865	-0.0152971	-0.013486865
β3	0.000345929	1.49156E-05	23.19242282	8.42221E-50	0.00031644	0.000375418	0.00031644	0.000375418

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.995452965
R Square	0.990926606
Adjusted R Square	0.990732176
Standard Error	0.025768075
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.15228252	3.384094173	5096.576002	1.0453E-142
Residual	140	0.092959113	0.000663994		
Total	143	10.24524163			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.282511839	0.008659725	32.62364879	2.704E-67	0.265391097	0.299632581	0.265391097	0.299632581
β1	0.204502598	0.003821666	53.51137044	4.3021E-95	0.196946958	0.212058237	0.196946958	0.212058237
β2	-0.014382652	0.000459186	-31.32206064	4.08566E-65	-0.015290487	-0.013474816	-0.015290487	-0.013474816
β3	0.000345898	1.49604E-05	23.12086258	1.18766E-49	0.00031632	0.000375475	0.00031632	0.000375475

Fixed Annual Costs for Crude Oil Wells

The fixed annual cost for crude oil wells was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Fixed annual costs consist of supervision and overhead costs, auto usage costs, operative supplies, labor costs, supplies and services costs, equipment usage and other costs.

The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \qquad (2.B\text{-}11)$$

where Cost = OMO_W
$\beta0$ = OMOK
$\beta1$ = OMOA
$\beta2$ = OMOB
$\beta3$ = OMOC
from equation 2-30 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. $\beta2$ and $\beta3$ are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9895
R Square	0.9792
Adjusted R Square	0.9584
Standard Error	165.6
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,290,021.8	1,290,021.8	47.0	0.1
Residual	1	27,419.5	27,419.5		
Total	2	1,317,441.3			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	6,026.949	202.804	29.718	0.021	3,450.097	8,603.802	3,450.097	8,603.802
β1	0.263	0.038	6.859	0.092	-0.224	0.750	-0.224	0.750

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.8631
R Square	0.7449
Adjusted R Square	0.6811
Standard Error	2,759.2
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	88,902,026.9	88,902,026.9	11.7	0.0
Residual	4	30,452,068.1	7,613,017.0		
Total	5	119,354,095.0			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	7,171.358	2,389.511	3.001	0.040	536.998	13,805.718	536.998	13,805.718
β1	1.543	0.452	3.417	0.027	0.289	2.797	0.289	2.797

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9888
R Square	0.9777
Adjusted R Square	0.9554
Standard Error	325.8
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4,654,650.4	4,654,650.4	43.9	0.1
Residual	1	106,147.3	106,147.3		
Total	2	4,760,797.7			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	5,572.283	399.025	13.965	0.046	502.211	10,642.355	502.211	10,642.355
β1	0.499	0.075	6.622	0.095	-0.459	1.458	-0.459	1.458

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9634
R Square	0.9282
Adjusted R Square	0.8923
Standard Error	455.6
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5,368,949.5	5,368,949.5	25.9	0.0
Residual	2	415,138.5	207,569.2		
Total	3	5,784,088.0			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	6,327.733	447.809	14.130	0.005	4,400.964	8,254.501	4,400.964	8,254.501
β1	0.302	0.059	5.086	0.037	0.046	0.557	0.046	0.557

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9908
R Square	0.9817
Adjusted R Square	0.9725
Standard Error	313.1
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	10,498,366.6	10,498,366.6	107.1	0.0
Residual	2	196,056.3	98,028.2		
Total	3	10,694,422.9			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	5,193.399	307.742	16.876	0.003	3,869.291	6,517.508	3,869.291	6,517.508
β1	0.422	0.041	10.349	0.009	0.246	0.597	0.246	0.597

Fixed Annual Costs for Oil Wells - Cost Adjustment Factor

The cost adjustment factor of the fixed annual cost for oil wells was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994014283
R Square	0.988064394
Adjusted R Square	0.987808631
Standard Error	0.026960479
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.424110153	2.808036718	3863.203308	2.2587E-134
Residual	140	0.101761442	0.000726867		
Total	143	8.525871595			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325522735	0.00906045	35.9278779	1.54278E-72	0.30760974	0.343435731	0.30760974	0.343435731
β1	0.019415379	0.000399851	48.55651174	1.74247E-89	0.018624852	0.020205906	0.018624852	0.020205906
β2	-0.000139999	4.80435E-06	-29.14014276	2.63883E-61	-0.000149498	-0.000130501	-0.000149498	-0.000130501
β3	3.41059E-07	1.56527E-08	21.78917295	7.98896E-47	3.10113E-07	3.72006E-07	3.10113E-07	3.72006E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.972995979
R Square	0.946721175
Adjusted R Square	0.945579485
Standard Error	0.052710031
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6.91165462	2.303884873	829.2285185	6.67464E-89
Residual	140	0.388968632	0.002778347		
Total	143	7.300623252			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.305890757	0.01771395	17.26835352	1.6689E-36	0.270869326	0.340912188	0.270869326	0.340912188
β1	0.019637228	0.000781743	25.11979642	1.01374E-53	0.01809168	0.021182776	0.01809168	0.021182776
β2	-0.000147609	9.39291E-06	-15.71490525	1.03843E-32	-0.000166179	-0.000129038	-0.000166179	-0.000129038
β3	3.60127E-07	3.06024E-08	11.76795581	1.17387E-22	2.99625E-07	4.2063E-07	2.99625E-07	4.2063E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.993998856
R Square	0.988033725
Adjusted R Square	0.987777305
Standard Error	0.02698784
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.419321124	2.806440375	3853.182417	2.7032E-134
Residual	140	0.10196809	0.000728344		
Total	143	8.521289214			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.32545185	0.009069645	35.88363815	1.80273E-72	0.307520675	0.343383025	0.307520675	0.343383025
β1	0.019419103	0.000400257	48.51658921	1.94263E-89	0.018627774	0.020210433	0.018627774	0.020210433
β2	-0.000140059	4.80922E-06	-29.12303298	2.83205E-61	-0.000149567	-0.000130551	-0.000149567	-0.000130551
β3	3.41232E-07	1.56686E-08	21.77807458	8.44228E-47	3.10254E-07	3.72209E-07	3.10254E-07	3.72209E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.977862049
R Square	0.956214186
Adjusted R Square	0.955275919
Standard Error	0.050111949
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	7.677722068	2.559240689	1019.127536	7.26235E-95
Residual	140	0.351569047	0.002511207		
Total	143	8.029291115			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.343679311	0.016840828	20.40750634	8.67459E-44	0.310384089	0.376974533	0.310384089	0.376974533
β1	0.020087054	0.000743211	27.02739293	2.04852E-57	0.018617686	0.021556422	0.018617686	0.021556422
β2	-0.000153877	8.92993E-06	-17.23164844	2.04504E-36	-0.000171532	-0.000136222	-0.000171532	-0.000136222
β3	3.91397E-07	2.9094E-08	13.45286338	5.31787E-27	3.33877E-07	4.48918E-07	3.33877E-07	4.48918E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.993729589
R Square	0.987498496
Adjusted R Square	0.987230606
Standard Error	0.027203598
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.183798235	2.727932745	3686.217436	5.7808E-133
Residual	140	0.103605007	0.000740036		
Total	143	8.287403242			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.330961672	0.009142153	36.20171926	5.90451E-73	0.312887144	0.3490362	0.312887144	0.3490362
β1	0.019295414	0.000403457	47.82521879	1.29343E-88	0.018497758	0.02009307	0.018497758	0.02009307
β2	-0.000139784	4.84767E-06	-28.83529781	9.33567E-61	-0.000149368	-0.0001302	-0.000149368	-0.0001302
β3	3.4128E-07	1.57939E-08	21.60840729	1.96666E-46	3.10055E-07	3.72505E-07	3.10055E-07	3.72505E-07

Fixed Annual Costs for Natural Gas Wells

Fixed annual costs for natural gas wells were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Fixed annual costs consist of the lease equipment costs for natural gas production for a given year. The data was analyzed on a regional level. The independent variables are depth and Q which is the flow rate of natural gas in million cubic feet. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Q + \beta3 * Depth * Q \quad (2.B\text{-}12)$$

where
Cost = FOAMG_W
$\beta0$ = OMGK
$\beta1$ = OMGA
$\beta2$ = OMGB
$\beta3$ = OMGC
Q = PEAKDAILY_RATE
from equation 2-29 in Chapter 2.

Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.928
R Square	0.861
Adjusted R Square	0.815
Standard Error	6,471.68
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	2,344,632,468.49	781,544,156.16	18.66	0.00
Residual	9	376,944,241.62	41,882,693.51		
Total	12	2,721,576,710.11			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,450.28	5,219.40	0.85	0.42	-7,356.84	16,257.40	-7,356.84	16,257.40
β1	2.50	0.45	5.58	0.00	1.49	3.51	1.49	3.51
β2	27.65	21.21	1.30	0.22	-20.33	75.63	-20.33	75.63
β3	0.00	0.00	-1.21	0.26	0.00	0.00	0.00	0.00

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.913
R Square	0.834
Adjusted R Square	0.807
Standard Error	6,564.36
Observations	23

ANOVA

	df	SS	MS	F	Significance F
Regression	3	4,100,685,576.61	1,366,895,192.20	31.72	0.00
Residual	19	818,725,806.73	43,090,831.93		
Total	22	4,919,411,383.34			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	11,145.70	3,224.45	3.46	0.00	4,396.85	17,894.55	4,396.85	17,894.55
β1	2.68	0.37	7.17	0.00	1.90	3.46	1.90	3.46
β2	7.67	5.09	1.51	0.15	-2.99	18.33	-2.99	18.33
β3	0.00	0.00	-1.21	0.24	0.00	0.00	0.00	0.00

Mid-Continent, applied to OLOGSS region 3 and 6:

Regression Statistics	
Multiple R	0.934
R Square	0.873
Adjusted R Square	0.830
Standard Error	6,466.88
Observations	13

ANOVA

	df	SS	MS	F	Significance F
Regression	3	2,578,736,610.45	859,578,870.15	20.55	0.00
Residual	9	376,384,484.71	41,820,498.30		
Total	12	2,955,121,095.16			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	8,193.82	5,410.04	1.51	0.16	-4,044.54	20,432.18	-4,044.54	20,432.18
β1	2.75	0.45	6.14	0.00	1.74	3.77	1.74	3.77
β2	21.21	18.04	1.18	0.27	-19.59	62.01	-19.59	62.01
β3	0.00	0.00	-1.12	0.29	0.00	0.00	0.00	0.00

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	0.945
R Square	0.893
Adjusted R Square	0.840
Standard Error	6,104.84
Observations	10

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1,874,387,985.75	624,795,995.25	16.76	0.00
Residual	6	223,614,591.98	37,269,098.66		
Total	9	2,098,002,577.72			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	7,534.86	6,340.77	1.19	0.28	-7,980.45	23,050.17	-7,980.45	23,050.17
β1	3.81	0.88	4.33	0.00	1.66	5.97	1.66	5.97
β2	32.27	22.33	1.44	0.20	-22.38	86.92	-22.38	86.92
β3	0.00	0.00	-1.18	0.28	-0.01	0.00	-0.01	0.00

Fixed Annual Costs for Gas Wells - Cost Adjustment Factor

The cost adjustment factor of the fixed annual cost for gas wells was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $1 to $20 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $5 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Gas\ Price + \beta2 * Gas\ Price^2 + \beta3 * Gas\ Price^3$$

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.994836789
R Square	0.989700237
Adjusted R Square	0.989479527
Standard Error	0.029019958
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	11.32916798	3.776389326	4484.181718	7.4647E-139
Residual	140	0.117902114	0.000842158		
Total	143	11.44707009			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.234219858	0.009752567	24.01622716	1.68475E-51	0.21493851	0.253501206	0.21493851	0.253501206
β1	0.216761767	0.004303953	50.36340872	1.37772E-91	0.20825262	0.225270914	0.20825262	0.225270914
β2	-0.015234638	0.000517134	-29.45972427	7.08872E-62	-0.01625704	-0.014212235	-0.01625704	-0.014212235
β3	0.000365319	1.68484E-05	21.68270506	1.3574E-46	0.000332009	0.000398629	0.000332009	0.000398629

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.995657421
R Square	0.991333701
Adjusted R Square	0.991147994
Standard Error	0.02551118
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.42258156	3.474193854	5338.176859	4.2055E-144
Residual	140	0.091114842	0.00065082		
Total	143	10.5136964			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.276966489	0.008573392	32.30535588	9.09319E-67	0.260016432	0.293916546	0.260016432	0.293916546
β1	0.205740933	0.003783566	54.37751691	5.03408E-96	0.198260619	0.213221246	0.198260619	0.213221246
β2	-0.014407802	0.000454608	-31.6927929	9.63037E-66	-0.015306587	-0.013509017	-0.015306587	-0.013509017
β3	0.00034576	1.48113E-05	23.34441529	4.06714E-50	0.000316478	0.000375043	0.000316478	0.000375043

Mid-Continent, Applied to OLOGSS Region 3 and 6:

Regression Statistics	
Multiple R	0.995590124
R Square	0.991199695
Adjusted R Square	0.991011117
Standard Error	0.025596313
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.33109303	3.443697678	5256.179662	1.231E-143
Residual	140	0.091723972	0.000655171		
Total	143	10.42281701			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.278704883	0.008602002	32.40000063	6.33409E-67	0.261698262	0.295711504	0.261698262	0.295711504
β1	0.205373482	0.003796192	54.09986358	9.97995E-96	0.197868206	0.212878758	0.197868206	0.212878758
β2	-0.014404563	0.000456125	-31.58028284	1.49116E-65	-0.015306347	-0.013502779	-0.015306347	-0.013502779
β3	0.000345945	1.48607E-05	23.27919988	5.55628E-50	0.000316565	0.000375325	0.000316565	0.000375325

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.995548929
R Square	0.99111767
Adjusted R Square	0.990927334
Standard Error	0.02564864
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.27673171	3.425577238	5207.209824	2.3566E-143
Residual	140	0.092099383	0.000657853		
Total	143	10.3688311			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.279731342	0.008619588	32.45298388	5.17523E-67	0.262689954	0.296772729	0.262689954	0.296772729
β1	0.205151971	0.003803953	53.93125949	1.51455E-95	0.197631352	0.21267259	0.197631352	0.21267259
β2	-0.014402579	0.000457058	-31.51151347	1.94912E-65	-0.015306207	-0.013498952	-0.015306207	-0.013498952
β3	0.00034606	1.48911E-05	23.23943141	6.72233E-50	0.00031662	0.000375501	0.00031662	0.000375501

Fixed Annual Costs for Secondary Production

The fixed annual cost for secondary oil production was calculated an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). The data was analyzed on a regional level. The secondary operations costs for each region were determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \qquad (2.B\text{-}13)$$

where Cost = OPSEC_W

β0 = OPSECK

β1 = OPSECA

β2 = OPSECB

β3 = OPSECC

from equation 2-31 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9972
R Square	0.9945
Adjusted R Square	0.9890
Standard Error	1,969.67
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	698,746,493.71	698,746,493.71	180.11	0.05
Residual	1	3,879,582.16	3,879,582.16		
Total	2	702,626,075.87			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	30,509.3	2,412.338	12.647	0.050	-142.224	61,160.827	-142.224	61,160.827
β1	6.118	0.456	13.420	0.047	0.326	11.911	0.326	11.911

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.935260
R Square	0.874710
Adjusted R Square	0.843388
Standard Error	8414.07
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,977,068,663.41	1,977,068,663.41	27.93	0.01
Residual	4	283,186,316.21	70,796,579.05		
Total	5	2,260,254,979.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	55,732.7	7,286.799	7.648	0.002	35,501.310	75,964.186	35,501.310	75,964.186
β1	7.277	1.377	5.285	0.006	3.454	11.101	3.454	11.101

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.998942
R Square	0.997884
Adjusted R Square	0.995768
Standard Error	1329.04
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	833,049,989.02	833,049,989.02	471.62	0.03
Residual	1	1,766,354.45	1,766,354.45		
Total	2	834,816,343.47			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	28,208.7	1,627.738	17.330	0.037	7,526.417	48,890.989	7,526.417	48,890.989
β1	6.680	0.308	21.717	0.029	2.772	10.589	2.772	10.589

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.989924
R Square	0.979949
Adjusted R Square	0.959899
Standard Error	3639.10
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	647,242,187.96	647,242,187.96	48.87	0.09
Residual	1	13,243,073.43	13,243,073.43		
Total	2	660,485,261.39			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	53,857.06	4,456.973	12.084	0.053	-2,773.909	110,488.034	-2,773.909	110,488.034
β1	5.888	0.842	6.991	0.090	-4.814	16.591	-4.814	16.591

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.992089
R Square	0.984240
Adjusted R Square	0.968480
Standard Error	5193.40
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,684,438,248.88	1,684,438,248.88	62.45	0.08
Residual	1	26,971,430.96	26,971,430.96		
Total	2	1,711,409,679.84			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	35,893.465	6,360.593	5.643	0.112	-44,925.189	116,712.119	-44,925.189	116,712.119
β1	9.499	1.202	7.903	0.080	-5.774	24.773	-5.774	24.773

Fixed Annual Costs for Secondary Production - Cost Adjustment Factor

The cost adjustment factor of the fixed annual costs for secondary production was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994022382
R Square	0.988080495
Adjusted R Square	0.987825078
Standard Error	0.026956819
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.433336986	2.811112329	3868.484883	2.0551E-134
Residual	140	0.101733815	0.00072667		
Total	143	8.535070802			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.325311813	0.00905922	35.90947329	1.646E-72	0.307401249	0.343222377	0.307401249	0.343222377
β1	0.019419982	0.000399797	48.57461816	1.65866E-89	0.018629562	0.020210402	0.018629562	0.020210402
β2	-0.000140009	4.80369E-06	-29.14604996	2.57525E-61	-0.000149506	-0.000130512	-0.000149506	-0.000130512
β3	3.41057E-07	1.56506E-08	21.79195958	7.87903E-47	3.10115E-07	3.71999E-07	3.10115E-07	3.71999E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.993830992
R Square	0.987700041
Adjusted R Square	0.987436471
Standard Error	0.027165964
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.296590955	2.765530318	3747.383987	1.8532E-133
Residual	140	0.103318541	0.00073799		
Total	143	8.399909496			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.321750317	0.009129506	35.24290662	1.74974E-71	0.303700794	0.33979984	0.303700794	0.33979984
β1	0.019369439	0.000402899	48.0752057	6.49862E-89	0.018572887	0.020165992	0.018572887	0.020165992
β2	-0.000140208	4.84096E-06	-28.96291516	5.49447E-61	-0.000149779	-0.000130638	-0.000149779	-0.000130638
β3	3.42483E-07	1.5772E-08	21.71459435	1.15795E-46	3.11301E-07	3.73665E-07	3.11301E-07	3.73665E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994021683
R Square	0.988079106
Adjusted R Square	0.987823658
Standard Error	0.026959706
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.43414809	2.811382697	3868.028528	2.0719E-134
Residual	140	0.101755604	0.000726826		
Total	143	8.535903693			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.325281756	0.00906019	35.90231108	1.68802E-72	0.307369274	0.343194238	0.307369274	0.343194238
β1	0.019420568	0.00039984	48.57088177	1.67561E-89	0.018630063	0.020211072	0.018630063	0.020211072
β2	-0.000140009	4.80421E-06	-29.14305099	2.60734E-61	-0.000149507	-0.000130511	-0.000149507	-0.000130511
β3	3.41049E-07	1.56523E-08	21.7891193	7.99109E-47	3.10103E-07	3.71994E-07	3.10103E-07	3.71994E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994023418
R Square	0.988082555
Adjusted R Square	0.987827181
Standard Error	0.026956158
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.434398087	2.811466029	3869.161392	2.0304E-134
Residual	140	0.101728825	0.000726634		
Total	143	8.536126912			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.325293493	0.009058998	35.90833165	1.65262E-72	0.307383368	0.343203618	0.307383368	0.343203618
β1	0.019420405	0.000399787	48.57686713	1.64854E-89	0.018630005	0.020210806	0.018630005	0.020210806
β2	-0.000140009	4.80358E-06	-29.14672886	2.56804E-61	-0.000149505	-0.000130512	-0.000149505	-0.000130512
β3	3.41053E-07	1.56502E-08	21.792237	7.86817E-47	3.10111E-07	3.71994E-07	3.10111E-07	3.71994E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.993899019
R Square	0.98783526
Adjusted R Square	0.987574587
Standard Error	0.027222624
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.42499532	2.808331773	3789.557133	8.5487E-134
Residual	140	0.103749972	0.000741071		
Total	143	8.528745292			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.327122709	0.009148547	35.75679345	2.81971E-72	0.30903554	0.345209878	0.30903554	0.345209878
β1	0.019283711	0.000403739	47.76280844	1.53668E-88	0.018485497	0.020081925	0.018485497	0.020081925
β2	-0.000138419	4.85106E-06	-28.53379985	3.28809E-60	-0.00014801	-0.000128828	-0.00014801	-0.000128828
β3	3.36276E-07	1.58049E-08	21.27670912	1.03818E-45	3.05029E-07	3.67523E-07	3.05029E-07	3.67523E-07

Lifting Costs

Lifting costs for crude oil wells were calculated using average an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Lifting costs consist of labor costs for the pumper, chemicals, fuel, power and water costs. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta 0 + \beta 1 * Depth + \beta 2 * Depth^2 + \beta 3 * Depth^3 \qquad (2.B-14)$$

where Cost = OML_W
β0 = OMLK
β1 = OMLA
β2 = OMLB
β3 = OMLC
from equation 2-32 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9994
R Square	0.9988
Adjusted R Square	0.9976
Standard Error	136.7
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	15,852,301	15,852,301	849	0
Residual	1	18,681	18,681		
Total	2	15,870,982			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	7,534.515	167.395	45.010	0.014	5,407.565	9,661.465	5,407.565	9,661.465
β1	0.922	0.032	29.131	0.022	0.520	1.323	0.520	1.323

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.8546
R Square	0.7304
Adjusted R Square	0.6764
Standard Error	2263.5
Observations	7

ANOVA

	df	SS	MS	F	Significance F
Regression	1	69,387,339	69,387,339	14	0
Residual	5	25,617,128	5,123,426		
Total	6	95,004,467			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	11,585.191	1,654.440	7.002	0.001	7,332.324	15,838.058	7,332.324	15,838.058
β1	0.912	0.248	3.680	0.014	0.275	1.549	0.275	1.549

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9997
R Square	0.9995
Adjusted R Square	0.9990
Standard Error	82.0
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	13,261,874	13,261,874	1,972	0
Residual	1	6,726	6,726		
Total	2	13,268,601			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	8,298.339	100.447	82.614	0.008	7,022.045	9,574.634	7,022.045	9,574.634
β1	0.843	0.019	44.403	0.014	0.602	1.084	0.602	1.084

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	1.0000
R Square	1.0000
Adjusted R Square	0.9999
Standard Error	11.5
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	3,979,238	3,979,238	30,138	0
Residual	1	132	132		
Total	2	3,979,370			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	10,137.398	14.073	720.342	0.001	9,958.584	10,316.212	9,958.584	10,316.212
β1	0.462	0.003	173.603	0.004	0.428	0.495	0.428	0.495

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9969
R Square	0.9937
Adjusted R Square	0.9874
Standard Error	1134.3
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	203,349,853	203,349,853	158	0
Residual	1	1,286,583	1,286,583		
Total	2	204,636,436			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	5,147.313	1,389.199	3.705	0.168	-12,504.063	22,798.689	-12,504.063	22,798.689
β1	3.301	0.263	12.572	0.051	-0.035	6.636	-0.035	6.636

Lifting Costs - Cost Adjustment Factor

The cost adjustment factor for lifting costs for was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.994419415
R Square	0.988869972
Adjusted R Square	0.988631472
Standard Error	0.026749137
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.900010642	2.966670214	4146.195026	1.6969E-136
Residual	140	0.100172285	0.000715516		
Total	143	9.000182927			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.314447949	0.008989425	34.97976138	4.49274E-71	0.296675373	0.332220525	0.296675373	0.332220525
β1	0.019667961	0.000396717	49.57683267	1.11119E-90	0.018883631	0.020452291	0.018883631	0.020452291
β2	-0.000140635	4.76668E-06	-29.50377541	5.91881E-62	-0.000150059	-0.000131211	-0.000150059	-0.000131211
β3	3.41221E-07	1.553E-08	21.97170644	3.23018E-47	3.10517E-07	3.71924E-07	3.10517E-07	3.71924E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994725637
R Square	0.989479094
Adjusted R Square	0.989253646
Standard Error	0.026400955
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.177423888	3.059141296	4388.946164	3.302E-138
Residual	140	0.097581462	0.00069701		
Total	143	9.275005349			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.307250046	0.008872414	34.62981435	1.58839E-70	0.289708807	0.324791284	0.289708807	0.324791284
β1	0.019843369	0.000391553	50.6786443	6.01683E-92	0.019069248	0.020617491	0.019069248	0.020617491
β2	-0.000141338	4.70464E-06	-30.04217841	6.6318E-63	-0.000150639	-0.000132036	-0.000150639	-0.000132036
β3	3.42235E-07	1.53279E-08	22.32765206	5.59173E-48	3.11931E-07	3.72539E-07	3.11931E-07	3.72539E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994625665
R Square	0.989280214
Adjusted R Square	0.989050504
Standard Error	0.026521235
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.087590035	3.029196678	4306.653909	1.2247E-137
Residual	140	0.09847263	0.000703376		
Total	143	9.186062664			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309274775	0.008912836	34.69993005	1.23231E-70	0.291653621	0.32689593	0.291653621	0.32689593
β1	0.019797213	0.000393337	50.33145871	1.49879E-91	0.019019565	0.020574861	0.019019565	0.020574861
β2	-0.000141221	4.72607E-06	-29.88132995	1.27149E-62	-0.000150565	-0.000131878	-0.000150565	-0.000131878
β3	3.42202E-07	1.53977E-08	22.22423366	9.29272E-48	3.1176E-07	3.72644E-07	3.1176E-07	3.72644E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994686146
R Square	0.98940053
Adjusted R Square	0.989173398
Standard Error	0.026467032
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.154328871	3.051442957	4356.069182	5.5581E-138
Residual	140	0.09807053	0.000700504		
Total	143	9.252399401			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.307664081	0.00889462	34.58990756	1.8356E-70	0.29007894	0.325249222	0.29007894	0.325249222
β1	0.019836272	0.000392533	50.53404116	8.79346E-92	0.019060214	0.020612331	0.019060214	0.020612331
β2	-0.000141357	4.71641E-06	-29.97123684	8.83426E-63	-0.000150681	-0.000132032	-0.000150681	-0.000132032
β3	3.42352E-07	1.53662E-08	22.27954719	7.08083E-48	3.11973E-07	3.72732E-07	3.11973E-07	3.72732E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.993880162
R Square	0.987797777
Adjusted R Square	0.987536301
Standard Error	0.027114753
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.332367897	2.777455966	3777.77319	1.0603E-133
Residual	140	0.102929375	0.00073521		
Total	143	8.435297272			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.326854136	0.009112296	35.86957101	1.8943E-72	0.308838638	0.344869634	0.308838638	0.344869634
β1	0.019394839	0.000402139	48.22916512	4.26E-89	0.018599788	0.02018989	0.018599788	0.02018989
β2	-0.000140183	4.83184E-06	-29.01231258	4.47722E-61	-0.000149736	-0.00013063	-0.000149736	-0.00013063
β3	3.41846E-07	1.57423E-08	21.71513554	1.15483E-46	3.10722E-07	3.72969E-07	3.10722E-07	3.72969E-07

Secondary Workover Costs

Secondary workover costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Secondary workover costs consist of workover rig services, remedial services and equipment repair. The data was analyzed on a regional level. The secondary operations costs for each region were determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \quad (2.B\text{-}15)$$

where Cost = SWK_W

β0 = OMSWRK

β1 = OMSWRA

β2 = OMSWRB

β3 = OMSWRC

from equation 2-33 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9993
R Square	0.9986
Adjusted R Square	0.9972
Standard Error	439.4
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	136,348,936	136,348,936	706	0
Residual	1	193,106	193,106		
Total	2	136,542,042			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,951.059	538.200	9.199	0.069	-1,887.392	11,789.510	-1,887.392	11,789.510
β1	2.703	0.102	26.572	0.024	1.410	3.995	1.410	3.995

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.9924
R Square	0.9849
Adjusted R Square	0.9811
Standard Error	1356.3
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	480,269,759	480,269,759	261	0
Residual	4	7,358,144	1,839,536		
Total	5	487,627,903			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	10,560.069	1,174.586	8.990	0.001	7,298.889	13,821.249	7,298.889	13,821.249
β1	3.587	0.222	16.158	0.000	2.970	4.203	2.970	4.203

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9989
R Square	0.9979
Adjusted R Square	0.9958
Standard Error	544.6
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	140,143,261	140,143,261	473	0
Residual	1	296,583	296,583		
Total	2	140,439,844			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,732.510	666.989	5.596	0.113	-4,742.355	12,207.375	-4,742.355	12,207.375
β1	2.740	0.126	21.738	0.029	1.138	4.342	1.138	4.342

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	0.9996
R Square	0.9991
Adjusted R Square	0.9983
Standard Error	290.9
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	98,740,186	98,740,186	1,167	0
Residual	1	84,627	84,627		
Total	2	98,824,812			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	5,291.954	356.287	14.853	0.043	764.922	9,818.987	764.922	9,818.987
β1	2.300	0.067	34.158	0.019	1.444	3.155	1.444	3.155

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9991
R Square	0.9983
Adjusted R Square	0.9966
Standard Error	454.7
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	120,919,119	120,919,119	585	0
Residual	1	206,762	206,762		
Total	2	121,125,881			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	4,131.486	556.905	7.419	0.085	-2,944.638	11,207.610	-2,944.638	11,207.610
β1	2.545	0.105	24.183	0.026	1.208	3.882	1.208	3.882

Secondary Workover Costs - Cost Adjustment Factor

The cost adjustment factor for secondary workover costs was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.994646805
R Square	0.989322267
Adjusted R Square	0.989093459
Standard Error	0.026416612
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.051925882	3.017308627	4323.799147	9.3015E-138
Residual	140	0.097697232	0.000697837		
Total	143	9.149623114			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.312179978	0.008877675	35.1646082	2.31513E-71	0.294628337	0.329731619	0.294628337	0.329731619
β1	0.019705242	0.000391785	50.29605017	1.64552E-91	0.018930662	0.020479822	0.018930662	0.020479822
β2	-0.000140397	4.70743E-06	-29.82464336	1.6003E-62	-0.000149704	-0.000131091	-0.000149704	-0.000131091
β3	3.4013E-07	1.53369E-08	22.17714344	1.1716E-47	3.09808E-07	3.70452E-07	3.09808E-07	3.70452E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994648271
R Square	0.989325182
Adjusted R Square	0.989096436
Standard Error	0.026409288
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.049404415	3.016468138	4324.992582	9.1255E-138
Residual	140	0.097643067	0.00069745		
Total	143	9.147047482			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.31224985	0.008875214	35.18223288	2.17363E-71	0.294703075	0.329796624	0.294703075	0.329796624
β1	0.019703773	0.000391676	50.30624812	1.60183E-91	0.018929408	0.020478139	0.018929408	0.020478139
β2	-0.000140393	4.70612E-06	-29.83187838	1.55398E-62	-0.000149697	-0.000131088	-0.000149697	-0.000131088
β3	3.40125E-07	1.53327E-08	22.18299399	1.13834E-47	3.09811E-07	3.70439E-07	3.09811E-07	3.70439E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994391906
R Square	0.988815263
Adjusted R Square	0.98857559
Standard Error	0.027366799
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.269694355	3.089898118	4125.685804	2.3918E-136
Residual	140	0.104851837	0.000748942		
Total	143	9.374546192			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.301399555	0.009196999	32.7715099	1.54408E-67	0.283216594	0.319582517	0.283216594	0.319582517
β1	0.020285999	0.000405877	49.980617	3.79125E-91	0.019483558	0.021088441	0.019483558	0.021088441
β2	-0.000145269	4.87675E-06	-29.78803686	1.85687E-62	-0.00015491	-0.000135627	-0.00015491	-0.000135627
β3	3.51144E-07	1.58886E-08	22.10035946	1.71054E-47	3.19731E-07	3.82556E-07	3.19731E-07	3.82556E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994645783
R Square	0.989320233
Adjusted R Square	0.989091381
Standard Error	0.026422924
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.054508298	3.018169433	4322.966602	9.4264E-138
Residual	140	0.097743924	0.000698171		
Total	143	9.152252223			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.312146343	0.008879797	35.15242029	2.41837E-71	0.294590508	0.329702178	0.294590508	0.329702178
β1	0.019706241	0.000391879	50.28658391	1.68714E-91	0.018931476	0.020481006	0.018931476	0.020481006
β2	-0.000140397	4.70855E-06	-29.81743751	1.64782E-62	-0.000149706	-0.000131088	-0.000149706	-0.000131088
β3	3.4012E-07	1.53406E-08	22.17121727	1.20629E-47	3.09791E-07	3.70449E-07	3.09791E-07	3.70449E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.994644139
R Square	0.989316964
Adjusted R Square	0.989088042
Standard Error	0.026428705
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.05566979	3.018556597	4321.629647	9.6305E-138
Residual	140	0.097786705	0.000698476		
Total	143	9.153456495			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.312123671	0.00888174	35.14217734	2.50872E-71	0.294563994	0.329683347	0.294563994	0.329683347
β1	0.019707015	0.000391964	50.27755672	1.72782E-91	0.01893208	0.020481949	0.01893208	0.020481949
β2	-0.0001404	4.70958E-06	-29.81159891	1.68736E-62	-0.000149711	-0.000131089	-0.000149711	-0.000131089
β3	3.40124E-07	1.5344E-08	22.16666321	1.23366E-47	3.09789E-07	3.7046E-07	3.09789E-07	3.7046E-07

Additional Cost Equations and Factors

The model uses several updated cost equations and factors originally developed for DOE/NETL's Comprehensive Oil and Gas Analysis Model (COGAM). These are:

- The crude oil and natural gas investment factors for tangible and intangible investments as well as the operating costs. These factors were originally developed based upon the 1984 Enhanced Oil Recovery Study completed by the National Petroleum Council.
- The G&A factors for capitalized and expensed costs.
- The limits on impurities, such as N2, CO2, and H2S used to calculate natural gas processing costs.
- Cost equations for stimulation, the produced water handling plant, the chemical handling plant, the polymer handling plant, CO_2 recycling plant, and the steam manifolds and pipelines.

Natural and Industrial CO2 Prices

The model uses regional CO_2 prices for both natural and industrial sources of CO_2. The cost equation for natural CO_2 is derived from the equation used in COGAM and updated to reflect current dollar values. According to University of Wyoming, this equation is applicable to the natural CO_2 in the Permian basin (Southwest). The cost of CO_2 in other regions and states is calculated using state calibration factors which represent the additional cost of transportation.

The industrial CO_2 costs contain two components: cost of capture and cost of transportation. The capture costs are derived using data obtained from Denbury Resources, Inc. and other sources. CO_2 capture costs range between \$20 and \$63/ton. The transportation costs were derived using an external economic model which calculates pipeline tariff based upon average distance, compression rate, and volume of CO_2 transported.

National Crude Oil Drilling Footage Equation

The equation for crude oil drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Oil Footage} = \beta 0 + \beta 1 * \text{Oil Price} \qquad (2.B\text{-}16)$$

where $\beta 0$ = OILA0

$\beta 1$ = OILA1

from equation 2-99 in Chapter 2.

Oil footage is the footage of total developmental crude oil wells drilled in the United States in thousands of feet. The crude oil price is a rolling five year average of crude oil prices from 1995 – 2008. The parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Oil Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9623
R Square	0.9259
Adjusted R Square	0.9167
Standard Error	5,108.20
Observations	10

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2,609,812,096.02	2,609,812,096.02	100.02	0.00
Residual	8	208,749,712.88	26,093,714.11		
Total	9	2,818,561,808.90			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,984.11	4,377.97	0.91	0.39	-6,111.51	14,079.72	-6,111.51	14,079.72
β1	1,282.45	128.23	10.00	0.00	986.74	1,578.16	986.74	1,578.16

Regional Crude Oil Footage Distribution

The regional drilling distributions for crude oil were estimated using an updated EIA well count file. The percent allocations for each region are calculated using the average footage drilled from 2004 – 2008 for developed crude oil or natural gas fields.

Region Name	States Included	Oil
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	7.6%
Gulf Coast	AL,FL,LA,MS,TX	29.3%
Midcontinent	AR,KS,MO,NE,OK,TX	16.8%
Southwest	TX,NM	18.3%
Rocky Mountains	CO,NV,UT,WY,NM	10.7%
West Coast	CA,WA	9.6%
Northern Great Plains	MT,ND,SD	7.6%

National Natural Gas Drilling Footage Equation

The equation for natural gas drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Gas Footage} = \beta 0 + \beta 1 * \text{Gas Price} \qquad (2.B\text{-}17)$$

where $\beta 0 = GASA0$
$\beta 1 = GASA1$
from equation 2-100 in Chapter 2.

Gas footage is footage of total developmental natural gas wells drilled in the United States in thousands of feet. The gas price is a rolling five year average of natural gas prices from 1995 – 2008. The parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Gas Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9189
R Square	0.8444
Adjusted R Square	0.7666
Standard Error	9,554.63
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	990,785,019.79	990,785,019.79	10.85	0.08
Residual	2	182,581,726.21	91,290,863.10		
Total	3	1,173,366,746.00			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	2,793.29	53,884.13	0.05	0.96	-229,051.57	234,638.14	-229,051.57	234,638.14
β1	30,429.72	9,236.81	3.29	0.08	-9,313.08	70,172.52	-9,313.08	70,172.52

Regional Natural Gas Footage Distribution

The regional drilling distributions for natural gas were estimated using an updated EIA well count file. The percent allocations for each region are calculated using the average footage drilled from 2004 – 2008 for developed crude oil or natural gas fields.

Region Name	States Included	Gas
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	13.2%
Gulf Coast	AL,FL,LA,MS,TX	18.7%
Midcontinent	AR,KS,MO,NE,OK,TX	13.4%
Southwest	TX,NM	34.5%
Rocky Mountains	CO,NV,UT,WY,NM	19.5%
West Coast	CA,WA	0.4%
Northern Great Plains	MT,ND,SD	0.4%

National Exploration Drilling Footage Equation

The equation for exploration well drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Exploration Footage} = \beta 0 + \beta 1 * \text{Oil Price} \qquad (2.B\text{-}18)$$

where $\beta 0 = \text{EXPA0}$
$\beta 1 = \text{EXPA1}$

Exploration footage is footage of total exploratory crude oil, natural gas and dry wells drilled in the United States in thousands of feet. The crude oil price is a rolling five year average of oil prices from 1995 – 2008. The parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Exploration Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9467
R Square	0.8963
Adjusted R Square	0.8834
Standard Error	2,825.10
Observations	10

ANOVA

	df	SS	MS	F	Significance F
Regression	1	552,044,623.08	552,044,623.08	69.17	0.00
Residual	8	63,849,573.82	7,981,196.73		
Total	9	615,894,196.90			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	4,733.91	2,421.24	1.96	0.09	-849.49	10,317.31	-849.49	10,317.31
β1	589.83	70.92	8.32	0.00	426.28	753.37	426.28	753.37

Regional Exploration Footage Distribution

The regional distribution for drilled exploration projects is also estimated using the updated EIA well count file. The percent allocations for each corresponding region are calculated using a 2004 – 2008 average of footage drilled for exploratory fields for both crude oil and natural gas.

Region Name	States Included	Exploration
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	22.3%
Gulf Coast	AL,FL,LA,MS,TX	9.0%
Midcontinent	AR,KS,MO,NE,OK,TX	28.8%
Southwest	TX,NM	14.3%
Rocky Mountains	CO,NV,UT,WY,NM	11.5%
West Coast	CA,WA	0.3%
Northern Great Plains	MT,ND,SD	13.8%

Regional Dryhole Rate for Discovered Projects

The percent allocation for existing regional dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each corresponding region. Existing dryhole rates calculate the projects which have already been discovered. The formula for the percentage is given below:

Existing Dryhole Rate = Developed Dryhole / Total Drilling (2.B-19)

Region Name	States Included	Existing
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	5.8%
Gulf Coast	AL,FL,LA,MS,TX	9.4%
Midcontinent	AR,KS,MO,NE,OK,TX	13.2%
Southwest	TX,NM	9.7%
Rocky Mountains	CO,NV,UT,WY,NM	4.3%
West Coast	CA,WA	1.5%
Northern Great Plains	MT,ND,SD	5.2%

Regional Dryhole Rate for First Exploration Well Drilled

The percent allocation for undiscovered regional exploration dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each region. Undiscovered regional exploration dryhole rates calculate the rate for the first well drilled in an exploration project. The formula for the percentage is given below:

Undiscovered Exploration = Exploration Dryhole / (Exploration Gas + Exploration Oil)

Region Name	States Included	Undisc. Exp
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	30.8%
Gulf Coast	AL,FL,LA,MS,TX	167.8%
Midcontinent	AR,KS,MO,NE,OK,TX	76.4%
Southwest	TX,NM	86.2%
Rocky Mountains	CO,NV,UT,WY,NM	74.0%
West Coast	CA,WA	466.0%
Northern Great Plains	MT,ND,SD	46.9%

Regional Dryhole Rate for Subsequent Exploration Wells Drilled

The percent allocation for undiscovered regional developed dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each corresponding region. Undiscovered regional developed dryhole rates calculate the rate for subsequent wells drilled in an exploration project. The formula for the percentage is given below:

Undiscovered Developed = (Developed Dryhole + Explored Dryhole) / Total Drilling (2.B-20)

Region Name	States Included	Undisc. Dev
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	7.3%
Gulf Coast	AL,FL,LA,MS,TX	11.6%
Midcontinent	AR,KS,MO,NE,OK,TX	16.8%
Southwest	TX,NM	10.8%
Rocky Mountains	CO,NV,UT,WY,NM	6.5%
West Coast	CA,WA	1.8%
Northern Great Plains	MT,ND,SD	10.5%

National Rig Depth Rating

The national rig depth rating schedule was calculated using a three year average based on the Smith Rig Count as reported by *Oil and Gas Journal*. Percentages are applied to determine the cumulative available rigs for drilling.

Appendix 2.C: Play-level Resource Assumptions for Tight Gas, Shale Gas, and Coalbed Methane

The detailed resource assumptions underlying the estimates of remaining unproved technically recoverable resources for tight gas, shale gas, and coalbed methane are presented in the following tables.

Table 2.C-1. Remaining Technically Recoverable Resources (TRR) – Tight Gas

REGION	BASIN	PLAY	AREA (mi^2)	WELL SPACING	DEPTH (ft)	EUR (bcf/well)	OFFICIAL NO ACCESS	TRR (bcf)
1	Appalachian	Berea Sandstone	51863	8	4000	0.18	0%	11401
1	Appalachian	Clinton/Medina High	14773	8	5900	0.25	0%	6786
1	Appalachian	Clinton/Medina Moderate/Low	27281	15	5200	0.08	0%	16136
1	Appalachian	Tuscarora Sandstone	42495	8	8000	0.69	0%	1485
1	Appalachian	Upper Devonian High	12775	10	4600	0.21	0%	10493
1	Appalachian	Upper Devonian Moderate/Low	29808	10	5400	0.06	0%	5492
2	East Texas	Cotton Valley/Bossier	2730	12	12500	1.39	0%	36447
2	Texas-Gulf	Olmos	2500	4	5000	0.44	0%	3624
2	Texas-Gulf	Vicksburg	600	8	11000	2.36	0%	4875
2	Texas-Gulf	Wilcox/Lobo	1500	8	9500	1.60	0%	8532
3	Anadarko	Cherokee/Redfork	1500	4	8500	0.90	0%	1168
3	Anadarko	Cleveland	1500	4	6500	0.91	0%	3690
3	Anadarko	Granite Wash/Atoka	1500	4	13000	1.72	0%	6871
3	Arkoma	Arkoma Basin	1000	8	8000	1.30	0%	2281
4	Permian	Abo	1500	8	3800	1.00	0%	9158
4	Permian	Canyon	6000	8	4500	0.22	0%	11535
5	Denver	Denver/Jules	3500	16	4999	0.24	1%	12953
5	Greater Green River	Deep Mesaverde	16416	4	15100	0.41	8%	2939
5	Greater Green River	Fort Union/Fox Hills	3858	8	5000	0.70	12%	1062
5	Greater Green River	Frontier (Deep)	15619	4	17000	2.58	9%	11303
5	Greater Green River	Frontier (Moxa Arch)	2334	8	9500	1.20	15%	3414
5	Greater Green River	Lance	5500	8	10000	6.60	11%	31541
5	Greater Green River	Lewis	5172	8	9500	1.32	6%	18893
5	Greater Green River	Shallow Mesaverde (1)	5239	4	9750	1.25	8%	12606
5	Greater Green River	Shallow Mesaverde (2)	6814	8	10500	0.67	8%	17874
5	Piceance	Iles/Mesaverde	972	8	8000	0.73	5%	1858
5	Piceance	North Williams Fork/Mesaverde	1008	8	8000	0.65	2%	4278
5	Piceance	South Williams Fork/Mesaverde	1008	32	7000	0.65	9%	22402
5	San Juan	Central Basin/Dakota	3918	6	6500	0.49	7%	15007
5	San Juan	Central Basin/Mesaverde	3689	8	4500	0.72	2%	8737
5	San Juan	Picture Cliffs	6558	4	3500	0.48	2%	4899
5	Uinta	Basin Flank Mesaverde	1708	8	8000	0.99	33%	5767
5	Uinta	Deep Synclinal Mesaverde	2893	8	18000	0.99	2%	3292
5	Uinta	Tertiary East	1600	16	6000	0.58	16%	5910
5	Uinta	Tertiary West	1603	8	6500	4.06	57%	10630
5	Williston	High Potential	2000	4	2300	0.61	4%	2960
5	Williston	Low Potential	3000	4	2500	0.21	1%	1886
5	Williston	Moderate Potential	2000	4	2300	0.33	4%	2071
5	Wind River	Fort Union/Lance Deep	2500	4	14500	0.54	9%	4261
5	Wind River	Fort Union/Lance Shallow	1500	8	11000	1.17	0%	13197
5	Wind River	Mesaverde/Frontier Deep	250	4	17000	1.99	9%	1221
5	Wind River	Mesaverde/Frontier Shallow	250	4	13500	1.25	0%	1037
6	Columbia	Basin Centered	1500	8	13100	1.26	0%	7508

Table 2.C-2. Remaining Technically Recoverable Resources (TRR) – Shale Gas

REGION	BASIN	PLAY	AREA (mi^2)	WELL SPACING	DEPTH (ft)	EUR (bcf/well)	OFFICIAL NO ACCESS	TRR (bcf)
1	Appalachian	Cincinatti Arch	6000	4	1800	0.12	0%	1435
1	Appalachian	Devonian Big Sandy - Active	8675	8	3800	0.32	0%	6490
1	Appalachian	Devonian Big Sandy - Undeveloped	1994	8	3800	0.32	0%	940
1	Appalachian	Devonian Greater Siltstone Area	22914	11	2911	0.20	0%	8463
1	Appalachian	Devonian Low Thermal Maturity	45844	7	3000	0.30	0%	13534
1	Appalachian	Marcellus - Active	10622	8	6750	3.49	0%	177931
1	Appalachian	Marcellus - Undeveloped	84271	8	6750	1.15	0%	232443
1	Illinois	New Albany	1600	8	2750	1.09	0%	10947
1	Michigan	Antrim	12000	7	1400	0.28	0%	20512
2	Black Warrior	Floyd-Neal/Conasauga	2429	2	8000	0.92	0%	4465
2	TX-LA-MS Salt	Haynesville - Active	3574	8	12000	6.48	0%	60615
2	TX-LA-MS Salt	Haynesville - Undeveloped	5426	8	12000	1.50	0%	19408
2	West Gulf Coast	Eagle Ford - Dry	200	4	7000	5.50	0%	4378
2	West Gulf Coast	Eagle Ford - Wet	890	8	7000	2.31	0%	16429
3	Anadarko	Cana Woodford	688	4	13500	3.42	0%	5718
3	Anadarko	Woodford - Central Oklahoma	1800	4	5000	1.01	0%	2946
3	Arkoma	Fayetteville - Central	4000	8	4000	2.29	0%	29505
3	Arkoma	Fayetteville - West	5000	8	4000	1.17	0%	4639
3	Arkoma	Woodford - Western Arkoma	2900	4	9500	4.06	0%	19771
4	Fort Worth	Barnett - Fort Worth Active	2649	5	7500	1.60	0%	15834
4	Fort Worth	Barnett - Fort Worth Undeveloped	477	8	7500	1.20	0%	4094
4	Permian	Barnett - Permian Active	1426	5	7500	1.60	0%	19871
4	Permian	Barnett - Permian Undeveloped	1906	8	7500	1.20	0%	15823
4	Permian	Barnett-Woodford	2691	4	10200	2.99	0%	32152
5	Greater Green River	Hilliard-Baxter-Mancos	16416	8	14750	0.18	0%	3770
5	San Juan	Lewis	7506	3	4500	1.53	0%	11638
5	Uinta	Mancos	6589	8	15250	1.00	0%	21021
5	Williston	Shallow Niobrara	10000	2	1000	0.46	4%	6757

Table 2.C-3. Remaining Technically Recoverable Resources (TRR) – Coalbed Methane

REGION	BASIN	PLAY	AREA (mi^2)	WELL SPACING	DEPTH (ft)	EUR (bcf/well)	OFFICIAL NO ACCESS	TRR (bcf)
1	Appalachian	Central Basin	3870	8	1900	0.18	0%	1709
1	Appalachian	North Appalachia - High	3817	12	1400	0.12	0%	532
1	Appalachian	North Appalachia - Mod/Low	8906	12	1800	0.08	0%	469
1	Illinois	Central Basin	1214	8	1000	0.12	0%	1161
2	Black Warrior	Extention Area	700	8	1900	0.08	0%	931
2	Black Warrior	Main Area	1000	12	1950	0.21	0%	2190
2	Cahaba	Cahaba Coal Field	387	8	3000	0.18	0%	379
3	Midcontinent	Arkoma	2998	8	1500	0.22	0%	3032
3	Midcontinent	Cherokee & Forest City	2750	8	1000	0.06	0%	1308
4	Raton	Southern	386	8	2000	0.37	2%	962
5	Greater Green River	Deep	3600	4	7000	0.60	15%	3879
5	Greater Green River	Shallow	720	8	1500	0.20	20%	1053
5	Piceance	Deep	2000	4	7000	0.60	3%	3677
5	Piceance	Divide Creek	144	8	3800	0.18	13%	194
5	Piceance	Shallow	2000	4	3500	0.30	9%	2230
5	Piceance	White River Dome	216	8	7500	0.41	8%	657
5	Powder River	Big George/Lower Fort Union	2880	16	1100	0.26	1%	5943
5	Powder River	Wasatch	216	8	1100	0.06	1%	92
5	Powder River	Wyodak/Upper Fort Union	3600	20	600	0.14	1%	18859
5	Raton	Northern	470	8	2500	0.35	0%	957
5	Raton	Purgatoire River	360	8	2000	0.31	0%	430
5	San Juan	Fairway NM	670	4	3250	1.14	7%	774
5	San Juan	North Basin	2060	4	3000	0.28	7%	1511
5	San Juan	North Basin CO	780	4	2800	1.51	7%	10474
5	San Juan	South Basin	1190	4	2000	0.20	7%	820
5	San Juan	South Menefee NM	7454	5	2500	0.10	7%	177
5	Uinta	Blackhawk	586	8	3250	0.16	5%	1864
5	Uinta	Ferron	400	8	3000	0.78	11%	1409
5	Uinta	Sego	534	4	3250	0.31	10%	417

3. Offshore Oil and Gas Supply Submodule

Introduction

The Offshore Oil and Gas Supply Submodule (OOGSS) uses a field-based engineering approach to represent the exploration and development of U.S. offshore oil and natural gas resources. The OOGSS simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore petroleum resources are divided into 3 categories:

- **Undiscovered Fields.** The number, location, and size of the undiscovered fields is based on the Minerals Management Service's (MMS) 2006 hydrocarbon resource assessment.[1] MMS was renamed Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) in 2010.

- **Discovered, Undeveloped Fields.** Any discovery that has been announced but is not currently producing is evaluated in this component of the model. The first production year is an input and is based on announced plans and expectations.

- **Producing Fields.** The fields in this category have wells that have produced oil and/or gas by 2009. The production volumes are from the BOEMRE production database.

Resource and economic calculations are performed at an evaluation unit basis. An evaluation unit is defined as the area within a planning area that falls into a specific water depth category. Planning areas are the Western Gulf of Mexico (GOM), Central GOM, Eastern GOM, Pacific, and Atlantic. There are six water depth categories: 0-200 meters, 200-400 meters, 400-800 meters, 800-1600 meters, 1600-2400 meters, and greater than 2400 meters. The crosswalk between region and evaluation unit is shown in Table 3-1.

Supply curves for crude oil and natural gas are generated for three offshore regions: Pacific, Atlantic, and Gulf of Mexico. Crude oil production includes lease condensate. Natural gas production accounts for both nonassociated gas and associated-dissolved gas. The model is responsive to changes in oil and natural gas prices, royalty relief assumptions, oil and natural gas resource base, and technological improvements affecting exploration and development.

Undiscovered Fields Component

Significant undiscovered oil and gas resources are estimated to exist in the Outer Continental Shelf, particularly in the Gulf of Mexico. Exploration and development of these resources is projected in this component of the OOGSS.

Within each evaluation unit, a field size distribution is assumed based on BOEMRE's latest[1] resource assessment (Table 3-2). The volume of resource in barrels of oil equivalence by field size class as defined by the BOEMRE is shown in Table 3-3. In the OOGSS, the mean estimate represents the size of each field in the field size class. Water depth and field size class are used for specifying many of the technology assumptions in the OOGSS. Fields smaller than field size class 2 are assumed to be uneconomic to develop.

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[1]U.S. Department of Interior, Minerals Management Service, *Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources*, February 2006.

Table 3-1. Offshore Region and Evaluation Unit Crosswalk

No.	Region Name	Planning Area	Water Depth (meters)	Drilling Depth (feet)	Evaluation Unit Name	Region ID
1	Shallow GOM	Western GOM	0 - 200	< 15,000	WGOM0002	3
2	Shallow GOM	Western GOM	0 - 200	> 15,000	WGOMDG02	3
3	Deep GOM	Western GOM	201 - 400	All	WGOM0204	4
4	Deep GOM	Western GOM	401 - 800	All	WGOM0408	4
5	Deep GOM	Western GOM	801 - 1,600	All	WGOM0816	4
6	Deep GOM	Western GOM	1,601 - 2,400	All	WGOM1624	4
7	Deep GOM	Western GOM	> 2,400	All	WGOM2400	4
8	Shallow GOM	Central GOM	0 - 200	< 15,000	CGOM0002	3
9	Shallow GOM	Central GOM	0 - 200	> 15,000	CGOMDG02	3
10	Deep GOM	Central GOM	201 - 400	All	CGOM0204	4
11	Deep GOM	Central GOM	401 - 800	All	CGOM0408	4
12	Deep GOM	Central GOM	801 - 1,600	All	CGOM0816	4
13	Deep GOM	Central GOM	1,601 – 2,400	All	CGOM1624	4
14	Deep GOM	Central GOM	> 2,400	All	CGOM2400	4
15	Shallow GOM	Eastern GOM	0 - 200	All	EGOM0002	3
16	Deep GOM	Eastern GOM	201 - 400	All	EGOM0204	4
17	Deep GOM	Central GOM	401 - 800	All	EGOM0408	4
18	Deep GOM	Eastern GOM	801 - 1600	All	EGOM0816	4
19	Deep GOM	Eastern GOM	1601 - 2400	All	EGOM1624	4
20	Deep GOM	Eastern GOM	> 2400	All	EGOM2400	4
21	Deep GOM	Eastern GOM	> 200	All	EGOML181	4
22	Atlantic	North Atlantic	0 - 200	All	NATL0002	1
23	Atlantic	North Atlantic	201 - 800	All	NATL0208	1
24	Atlantic	North Atlantic	> 800	All	NATL0800	1
25	Atlantic	Mid Atlantic	0 - 200	All	MATL0002	1
26	Atlantic	Mid Atlantic	201 - 800	All	MATL0208	1
27	Atlantic	Mid Atlantic	> 800	All	MATL0800	1
28	Atlantic	South Atlantic	0 - 200	All	SATL0002	1
29	Atlantic	South Atlantic	201 - 800	All	SATL0208	1
30	Atlantic	South Atlantic	> 800	All	SATL0800	1
31	Atlantic	Florida Straits	0 – 200	All	FLST0002	1
32	Atlantic	Florida Straits	201 - 800	All	FLST0208	1
33	Atlantic	Florida Straits	> 800	All	FLST0800	1
34	Pacific	Pacific Northwest	0-200	All	PNW0002	2
35	Pacific	Pacific Northwest	201-800	All	PNW0208	2
36	Pacific	North California	0-200	All	NCA0002	2
37	Pacific	North California	201-800	All	NCA0208	2
38	Pacific	North California	801-1600	All	NCA0816	2
39	Pacific	North California	1600-2400	All	NCA1624	2
40	Pacific	Central California	0-200	All	CCA0002	2
41	Pacific	Central California	201-800	All	CCA0208	2
42	Pacific	Central California	801-1600	All	CCA0816	2
43	Pacific	South California	0-200	All	SCA0002	2
44	Pacific	South California	201-800	All	SCA0208	2
45	Pacific	South California	801-1600	All	SCA0816	2
46	Pacific	South California	1601-2400	All	SCA1624	2

Source: U.S. Energy Information Administration, Energy Analysis, Office of Petroleum, Gas, and Biofuels Analysis

Table 3-2. Number of Undiscovered Fields by Evaluation Unit and Field Size Class, as of January 1, 2003

Evaluation Unit	Field Size Class (FSC)																Number of Fields	Total Resource (BBOE)
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17		
WGOM0002	1	5	11	14	20	23	24	27	30	8	6	8	2	0	0	0	179	4.348
WGOMDG02	0	0	2	4	5	6	8	9	9	3	2	2	1	0	0	0	51	1.435
WGOM0204	0	0	0	0	0	0	2	3	3	4	2	1	1	0	0	0	16	1.027
WGOM0408	0	0	0	0	0	1	3	3	7	7	3	2	1	0	0	0	27	1.533
WGOM0816	0	0	0	0	0	0	4	7	16	16	15	9	3	2	1	0	73	8.082
WGOM1624	0	0	0	1	2	6	10	14	18	18	14	10	6	4	1	0	104	10.945
WGOM2400	0	0	0	0	2	3	3	6	7	6	5	3	3	2	0	0	40	4.017
CGOM0002	1	1	6	11	28	52	79	103	81	53	20	1	0	0	0	0	436	8.063
CGOMDG02	0	0	1	1	4	4	4	6	7	6	5	3	1	0	0	0	42	3.406
CGOM0204	0	0	0	0	0	0	1	2	3	2	2	2	1	0	0	0	13	1.102
CGOM0408	0	0	0	0	0	1	1	4	4	4	1	1	1	1	0	0	18	1.660
CGOM0816	0	0	0	0	2	4	8	11	20	22	19	14	7	3	1	0	111	11.973
CGOM1624	0	0	0	1	2	5	9	15	18	19	15	13	8	4	1	0	110	12.371
CGOM2400	0	0	0	0	2	2	3	5	5	5	5	4	3	2	0	0	36	4.094
EGOM0002	4	6	7	11	16	18	18	16	13	10	6	1	0	0	0	0	126	1.843
EGOM0204	0	1	1	2	3	4	4	3	1	1	1	0	0	0	0	0	21	0.233
EGOM0408	0	1	2	3	5	5	5	4	3	2	1	0	0	0	0	0	31	0.348
EGOM0816	0	1	1	3	4	4	4	3	3	2	1	0	0	0	0	0	26	0.326
EGOM1624	0	0	0	0	2	1	1	1	0	1	0	1	0	0	0	0	7	0.250
EGOM2400	0	0	0	1	1	3	5	7	8	9	7	6	3	2	0	0	52	4.922
EGOML181	0	0	0	0	1	3	3	5	8	5	4	2	2	1	1	0	35	1.836
NATL0002	5	7	10	14	16	17	15	11	10	8	3	2	1	0	0	0	119	1.896
NATL0208	1	1	1	2	2	3	3	3	2	1	1	0	0	0	0	0	20	0.246
NATL0800	1	2	3	5	7	10	13	12	7	6	4	1	0	0	0	0	71	1.229
MATL0002	4	6	8	12	13	14	13	11	8	7	5	2	0	0	0	0	103	1.585
MATL0208	1	1	2	3	3	3	3	4	2	2	2	2	0	0	0	0	28	0.377
MATL0800	2	4	5	8	9	10	10	8	5	5	3	2	0	0	0	0	71	1.173
SATL0002	1	2	2	3	5	6	5	5	4	4	1	1	0	0	0	0	39	0.658
SATL0208	4	5	7	10	12	13	12	10	8	7	3	2	0	0	0	0	93	1.382
SATL0800	2	2	4	5	9	15	20	17	11	7	2	1	1	0	0	0	96	1.854
FLST0002	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	0.012
FLST0208	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	2	0.009
FLST0800	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000
PNW0002	10	17	24	29	27	21	13	8	5	2	1	0	0	0	0	0	157	0.597
PNW0208	4	6	9	10	11	7	6	3	2	1	0	0	0	0	0	0	59	0.209
NCA0002	1	2	3	5	5	5	5	4	3	3	2	0	0	0	0	0	38	0.485
NCA0208	9	17	24	28	26	22	15	10	5	3	1	1	0	0	0	0	161	0.859
NCA0816	3	6	9	12	12	11	9	7	4	3	2	1	0	0	0	0	79	0.784
NCA1624	1	2	3	5	6	6	7	6	4	2	1	1	0	0	0	0	44	0.595
CCA0002	1	4	6	11	15	19	20	17	12	8	4	2	0	0	0	0	119	1.758
CCA0208	1	2	3	5	8	10	10	8	7	5	2	0	0	0	0	0	61	0.761
CCA0816	0	1	1	2	3	4	5	3	2	2	0	0	0	0	0	0	23	0.218
SCA0002	1	2	4	10	16	21	22	19	12	6	2	1	0	0	0	0	116	1.348
SCA0208	3	6	12	25	38	49	51	43	28	14	5	3	1	0	0	0	278	3.655
SCA0816	1	3	6	9	13	17	18	15	12	8	2	2	1	0	0	0	107	1.906
SCA1624	0	1	2	3	4	5	5	5	4	3	1	1	0	0	0	0	34	0.608

Source: U.S. Energy Information Administration, Energy Analysis, Office of Petroleum, Gas, and Biofuels Analysis

Table 3-3. BOEMRE Field Size Definition (MMBOE)

Field Size Class	Mean
2	0.083
3	0.188
4	0.356
5	0.743
6	1.412
7	2.892
8	5.919
9	11.624
10	22.922
11	44.768
12	89.314
13	182.144
14	371.727
15	690.571
16	1418.883
17	2954.129

Source: Bureau of Ocean Energy Management, Regulation, and Enforcement

Projection of Discoveries

The number and size of discoveries is projected based on a simple model developed by J. J. Arps and T. G. Roberts in 1958[2]. For a given evaluation unit in the OOGSS, the number of cumulative discoveries for each field size class is determined by

$$\text{DiscoveredFields}_{\text{EU,iFSC}} = \text{TotalFields}_{\text{EU,iFSC}} * (1 - e^{\gamma_{\text{EU,iFSC}} * \text{CumNFW}_{\text{EU}}}) \qquad (3\text{-}1)$$

where,

TotalFields	=	Total number of fields by evaluation unit and field size class
CumNFW	=	Cumulative new field wildcats drilled in an evaluation unit
γ	=	search coefficient
EU	=	evaluation unit
iFSC	=	field size class.

The search coefficient (γ) was chosen to make the Equation 3-1 fit the data. In many cases, however, the sparse exploratory activity in an evaluation unit made fitting the discovery model problematic. To provide reasonable estimates of the search coefficient in every evaluation unit, the data in various field size classes within a region were grouped as needed to obtain enough data points to provide a reasonable fit to the discovery model. A polynomial was fit to all of the relative search coefficients in the region. The polynomial was fit to the resulting search coefficients as follows:

[2]Arps, J. J. and T. G. Roberts, *Economics of Drilling for Cretaceous Oil on the East Flank of the Denver-Julesburg Basin*, Bulletin of the American Association of Petroleum Geologists, November 1958.

$$\gamma_{\mathrm{EU,iFSC}} = \beta 1 * \mathrm{iFSC}^2 + \beta 2 * \mathrm{iFSC} + \beta 3 * \gamma_{\mathrm{EU,10}} \qquad (3\text{-}2)$$

where

β1	=	0.0243 for Western GOM and 0.0399 for Central and Eastern GOM
β2	=	-0.3525 for Western GOM and -0.6222 for Central and Eastern GOM
β3	=	1.5326 for Western GOM and 2.2477 for Central and 3.0477 for Eastern GOM
iFSC	=	field size class
γ	=	search coefficient for field size class 10.

Cumulative new field wildcat drilling is determined by

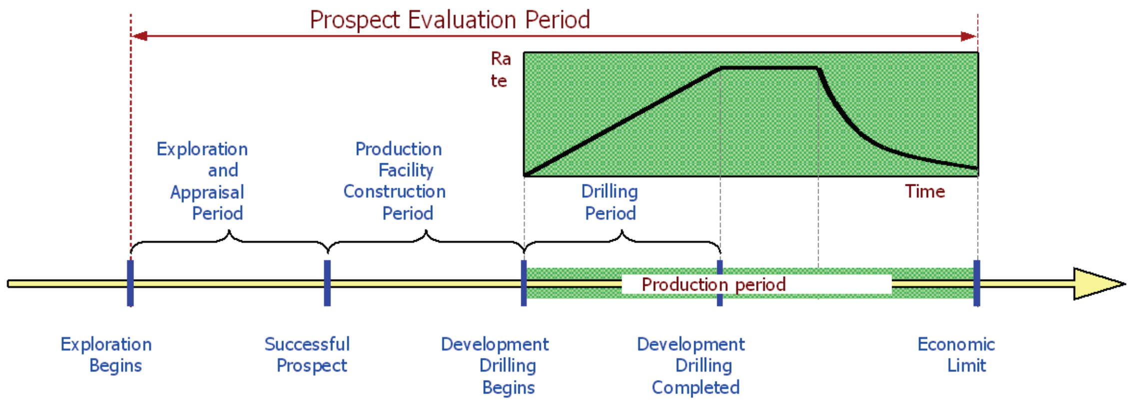
$$\mathrm{CumNFW}_{\mathrm{EU,t}} = \mathrm{CumNFW}_{\mathrm{EU,t-1}} + \alpha 1_{\mathrm{EU}} + \beta_{\mathrm{EU}} * (\mathrm{OILPRICE}_{\mathrm{t-nlag1}} * \mathrm{GASPRICE}_{\mathrm{t-nlag2}}) \qquad (3\text{-}3)$$

where

OILPRICE	=	oil wellhead price
GASPRICE	=	natural gas wellhead price
α1, β	=	estimated parameter
nlag1	=	number of years lagged for oil price
nlag2	=	number of years lagged for gas price
EU	=	evaluation unit

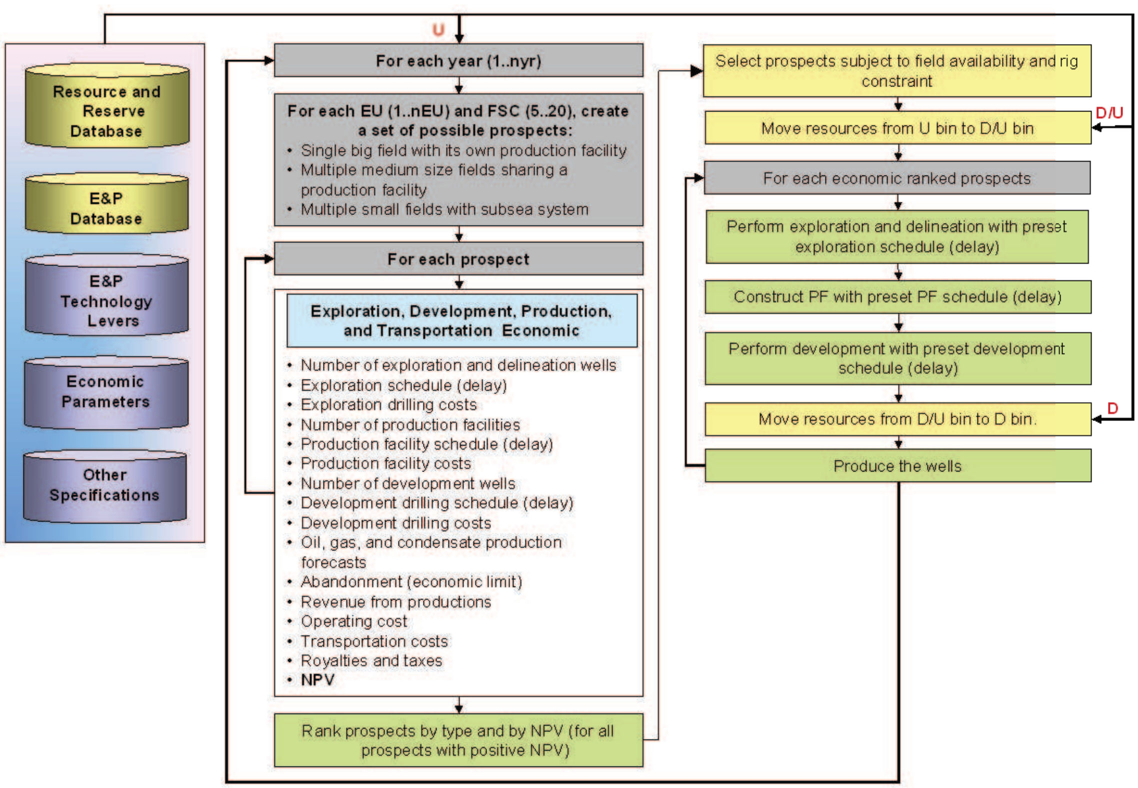
The decision for exploration and development of the discoveries determine from Equation 3-1 is performed at a prospect level that could involve more than one field. A prospect is defined as a potential project that covers exploration, appraisal, production facility construction, development, production, and transportation (Figure 3-1). There are three types of prospects: (1) a single field with its own production facility, (2) multiple medium size fields sharing a production facility, and (3) multiple small fields utilizing nearby production facility. The net present value (NPV) of each possible prospect is generated using the calculated exploration costs, production facility costs, development costs, completion costs, operating costs, flowline costs, transportation costs, royalties, taxes, and production revenues. Delays for exploration, production facility construction, and development are incorporated in this NPV calculation. The possible prospects are then ranked from best (highest NPV) to worst (lowest NPV). The best prospects are selected subject to field availability and rig constraint. The basic flowchart is presented in Figure 3-2.

Figure 3-1. Prospect Exploration, Development, and Production Schedule



Source: ICF Consulting

Figure 3-2. Flowchart for the Undiscovered Field Component of the OOGSS



Note: U = Undiscovered, D/U = Discovered/Undeveloped, D=Developed
Source: ICF Consulting

Calculation of Costs

The technology employed in the deepwater offshore areas to find and develop hydrocarbons can be significantly different than that used in shallower waters, and represents significant challenges for the companies and individuals involved in the deepwater development projects. In many situations in the deepwater OCS, the choice of technology used in a particular situation depends on the size of the prospect being developed. The following base costs are adjusted with the oil price to capture the variation in costs over time as activity level and demand for equipment and other supplies change. The adjustment factor is [1 + (oilprice/baseprice – 1)*0.4], where baseprice = $30/barrel.

Exploration Drilling

During the exploration phase of an offshore project, the type of drilling rig used depends on both economic and technical criteria. Offshore exploratory drilling usually is done using self-contained rigs that can be moved easily. Three types of drilling rigs are incorporated into the OOGSS. The exploration drilling costs per well for each rig type are a function of water depth (WD) and well drilling depth (DD), both in feet.

Jack-up rigs are limited to a water depth of about 600 feet or less. Jack-ups are towed to their location where heavy machinery is used to jack the legs down into the water until they rest on the ocean floor. When this is completed, the platform containing the work area rises above the water. After the platform has risen about 50 feet out of the water, the rig is ready to begin drilling.

$$\text{ExplorationDrillingCosts(\$/well)} = 2{,}000{,}000 + (5.0\text{E-}09)*WD*DD^3 \quad (3\text{-}4)$$

Semi-submersible rigs are floating structures that employ large engines to position the rig over the hole dynamically. This extends the maximum operating depth greatly, and some of these rigs can be used in water depths up to and beyond 3,000 feet. The shape of a semisubmersible rig tends to dampen wave motion greatly regardless of wave direction. This allows its use in areas where wave action is severe.

$$\text{ExplorationDrillingCosts(\$/well)} = 2{,}500{,}000 + 200*(WD+DD) + WD*(400+(2.0\text{E-}05)*DD^2) \quad (3\text{-}5)$$

Dynamically positioned drill ships are a second type of floating vessel used in offshore drilling. They are usually used in water depths exceeding 3,000 feet where the semi-submersible type of drilling rigs can not be deployed. Some of the drillships are designed with the rig equipment and anchoring system mounted on a central turret. The ship is rotated about the central turret using thrusters so that the ship always faces incoming waves. This helps to dampen wave motion.

$$\text{ExplorationDrillingCosts(\$/well)} = 7{,}000{,}000 + (1.0\text{E-}05)*WD*DD^2 \quad (3\text{-}6)$$

Water depth is the primary criterion for selecting a drilling rig. Drilling in shallow waters (up to 1,500 feet) can be done with jack-up rigs. Drilling in deeper water (greater than 1,500 feet) can be done with semi-submersible drilling rigs or drill ships. The number of rigs available for exploration is limited and varies by water depth levels. Drilling rigs are allowed to move one water depth level lower if needed.

Production and Development Structure

Six different options for development/production of offshore prospects are currently assumed in OOGSS, based on those currently considered and/or employed by operators in Gulf of Mexico OCS. These are the conventional fixed platforms, the compliant towers, tension leg platforms, Spar platforms, floating production systems and subsea satellite well systems. Choice of platform tends to be a function of the size of field and water depth, though in reality other operational, environmental, and/or economic decisions influence the choice. Production facility costs are a function of water depth (WD) and number of slots per structure (SLT).

Conventional Fixed Platform (FP). A fixed platform consists of a jacket with a deck placed on top, providing space for crew quarters, drilling rigs, and production facilities. The jacket is a tall vertical section made of tubular steel members supported by piles driven into the seabed. The fixed platform is economical for installation in water depths up to 1,200 feet. Although advances in engineering design and materials have been made, these structures are not economically feasible in deeper waters.

$$\mathrm{StructureCost}(\$) = 2{,}000{,}000 + 9{,}000 * \mathrm{SLT} + 1{,}500 * \mathrm{WD} * \mathrm{SLT} + 40 * \mathrm{WD}^2 \qquad (3\text{-}7)$$

Compliant Towers (CT). The compliant tower is a narrow, flexible tower type of platform that is supported by a piled foundation. Its stability is maintained by a series of guy wires radiating from the ower and terminating on pile or gravity anchors on the sea floor. The compliant tower can withstand significant forces while sustaining lateral deflections, and is suitable for use in water depths of 1,200 to 3,000 feet. A single tower can accommodate up to 60 wells; however, the compliant tower is constrained by limited deck loading capacity and no oil storage capacity.

$$\mathrm{StructureCost}(\$) = (\mathrm{SLT} + 30) * (1{,}500{,}000 + 2{,}000 * (\mathrm{WD} - 1{,}000)) \qquad (3\text{-}8)$$

Tension Leg Platform (TLP). The tension leg platform is a type of semi-submersible structure which is attached to the sea bed by tubular steel mooring lines. The natural buoyancy of the platform creates an upward force which keeps the mooring lines under tension and helps maintain vertical stability. This type of platform becomes a viable alternative at water depths of 1,500 feet and is considered to be the dominant system at water depths greater than 2,000 feet. Further, the costs of the TLP are relatively insensitive to water depth. The primary advantages of the TLP are its applicability in ultra-deepwaters, an adequate deck loading capacity, and some oil storage capacity. In addition, the field production time lag for this system is only about 3 years.

$$\mathrm{StructureCost}(\$) = (\mathrm{SLT} + 30) * (3{,}000{,}000 + 750 * (\mathrm{WD} - 1{,}000)) \qquad (3\text{-}9)$$

Floating Production System (FPS). The floating production system, a buoyant structure, consists of a semi-submersible or converted tanker with drilling and production equipment anchored in place with wire rope and chain to allow for vertical motion. Because of the movement of this structure in severe environments, the weather-related production downtime is estimated to be about 10 percent. These structures can only accommodate a maximum of approximately 25 wells. The wells are completed subsea on the ocean floor and are connected to the production deck through a riser system designed to accommodate platform motion. This system is suitable for marginally economic fields in water depths up to 4,000 feet.

$$\text{StructureCost}(\$) = (\text{SLT} + 20) * (7{,}500{,}000 + 250 * (\text{WD} - 1{,}000)) \tag{3-10}$$

Spar Platform (SPAR). A Spar Platform consists of a large diameter single vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (production, drilling, and export), and a hull which is moored using a taut caternary system of 6 to 20 lines anchored into the seafloor. Spar platforms are presently used in water depths up to 3,000 feet, although existing technology is believed to be able to extend this to about 10,000 feet.

$$\text{StructureCost}(\$) = (\text{SLT} + 20) * (3{,}000{,}000 + 500 * (\text{WD} - 1{,}000)) \tag{3-11}$$

Subsea Wells System (SS). Subsea systems range from a single subsea well tied back to a nearby production platform (such as FPS or TLP) to a set of multiple wells producing through a common subsea manifold and pipeline system to a distant production facility. These systems can be used in water depths up to at least 7,000 feet. Since the cost to complete a well is included in the development well drilling and completion costs, no cost is assumed for the subsea well system. However, a subsea template is required for all development wells producing to any structure other than a fixed platform.

$$\text{SubseaTemplateCost}(\$ / \text{well}) = 2{,}500{,}000 \tag{3-12}$$

The type of production facility for development and production depends on water depth level as shown in Table 3-4.

Table 3-4. Production Facility by Water Depth Level

Water Depth Range (feet)		Production Facility Type					
Minimum	Maximum	FP	CT	TLP	FPS	SPAR	SS
0	656	X					X
656	2625		X				X
2625	5249			X			X
5249	7874				X	X	X
7874	10000				X	X	X

Source: ICF Consulting

Development Drilling

Pre-drilling of development wells during the platform construction phase is done using the drilling rig employed for exploration drilling. Development wells drilled after installation of the platform which also serves as the development structure is done using the platform itself. Hence, the choice of drilling rig for development drilling is tied to the choice of the production platform.

For water depths less than or equal to 900 meters,

$$\begin{aligned}\text{DevelopmentDrillingCost}(\$ / \text{well}) = 1{,}500{,}000 + (1{,}500 + 0.04 * \text{DD}) * \text{WD} \\ +(0.035 * \text{DD} - 300) * \text{DD}\end{aligned} \tag{3-13}$$

For water depths greater tan 900 meters,

$$\begin{aligned}\text{DevelopmentDrillingCost}(\$ / \text{well}) = 4{,}500{,}000 + (150 + 0.004 * \text{DD}) * \text{WD} \\ +(0.035 * \text{DD} - 250) * \text{DD}\end{aligned} \tag{3-14}$$

where

WD = water depth in feet
DD = drilling depth in feet.

Completion and Operating

Completion costs per well are a function of water depth range and drilling depth as shown in Table 3-5.

Table 3-5. Well Completion and Equipment Costs per Well

Water Depth (feet)	**Development Drilling Depth (feet)**		
	< 10,000	**10,001 - 20,000**	**> 20,000**
0 - 3,000	800,000	2,100,000	3,300,000
> 3,000	1,900,000	2,700,000	3,300,000

Platform operating costs for all types of structures are assumed to be a function of water depth (WD) and the number of slots (SLT). These costs include the following items:

- primary oil and gas production costs,
- labor,
- communications and safety equipment,
- supplies and catering services,
- routine process and structural maintenance,
- well service and workovers,
- insurance on facilities, and
- transportation of personnel and supplies.

Annual operating costs are estimated by

$$\text{OperatingCost}(\$ / \text{structure} / \text{year}) = 1{,}265{,}000 + 135{,}000 * \text{SLT} + 0.0588 * \text{SLT} * \text{WD}^2 \qquad (3\text{-}15)$$

Transportation

It is assumed in the model that existing trunk pipelines will be used and that the prospect economics must support only the gathering system design and installation. However, in case of small fields tied back to some existing neighboring production platform, a pipeline is assumed to be required to transport the crude oil and natural gas to the neighboring platform.

Structure and Facility Abandonment

The costs to abandon the development structure and production facilities depend on the type of production technology used. The model projects abandonment costs for fixed platforms and compliant towers assuming that the structure is abandoned. It projects costs for tension leg platforms, converted semi-submersibles, and converted tankers assuming that the structures are removed for transport to another location for reinstallation. These costs are treated as intangible capital investments and are expensed in the year following cessation of production. Based on historical data, these costs are estimated as a fraction of the initial structure costs, as follows:

	Fraction of Initial Platform Cost
Fixed Platform	0.45
Compliant Tower	0.45
Tension Leg Platform	0.45
Floating Production Systems	0.15
Spar Platform	0.15

Exploration, Development, and Production Scheduling

The typical offshore project development consists of the following phases:[3]

- Exploration phase,
    - Exploration drilling program
    - Delineation drilling program
- Development phase,
- Fabrication and installation of the development/production platform,
    - Development drilling program
    - Pre-drilling during construction of platform
    - Drilling from platform
    - Construction of gathering system
- Production operations, and
- Field abandonment.

[3]The pre-development activities, including early field evaluation using conventional geological and geophysical methods and the acquisition of the right to explore the field, are assumed to be completed before initiation of the development of the prospect.

The timing of each activity, relative to the overall project life and to other activities, affects the potential economic viability of the undiscovered prospect. The modeling objective is to develop an exploration, development, and production plan which both realistically portrays existing and/or anticipated offshore practices and also allows for the most economical development of the field. A description of each of the phases is provided below.

Exploration Phase

An undiscovered field is assumed to be discovered by a successful exploration well (i.e., a new field wildcat). Delineation wells are then drilled to define the vertical and areal extent of the reservoir.

Exploration drilling. The exploration success rate (ratio of the number of field discovery wells to total wildcat wells) is used to establish the number of exploration wells required to discover a field as follows:

number of exploratory wells = 1/ [exploration success rate]

For example, a 25 percent exploration success rate will require four exploratory wells: one of the four wildcat wells drilled finds the field and the other three are dry holes.

Delineation drilling. Exploratory drilling is followed by delineation drilling for field appraisal (1 to 4 wells depending on the size of the field). The delineation wells define the field location vertically and horizontally so that the development structures and wells may be set in optimal positions. All delineation wells are converted to production wells at the end of the production facility construction.

Development Phase

During this phase of an offshore project, the development structures are designed, fabricated, and installed; the development wells (successful and dry) are drilled and completed; and the product transportation/gathering system is installed.

Development structures. The model assumes that the design and construction of any development structure begins in the year following completion of the exploration and delineation drilling program. However, the length of time required to complete the construction and installation of these structures depends on the type of system used. The required time for construction and installation of the various development structures used in the model is shown in Table 3-6. This time lag is important in all offshore developments, but it is especially critical for fields in deepwater and for marginally economic fields.

Development drilling schedule. The number of development wells varies by water depth and field size class as follows.

$$\text{DevelopmentWells} = \frac{5}{\text{FSC}} * \text{FSIZE}^{\beta_{\text{DepthClass}}} \tag{3-16}$$

where

FSC = field size class
FSIZE = resource volume (MMBOE)

β = 0.8 for water depths < 200 meters; 0.7 for water depths 200-800 meters; 0.65 for water depths > 800 meters.

Table 3-6. Production Facility Design, Fabrication, and Installation Period (Years)

PLATFORMS	Water Depth (Feet)														
Number of Slots	**0**	**100**	**400**	**800**	**1000**	**1500**	**2000**	**3000**	**4000**	**5000**	**6000**	**7000**	**8000**	**9000**	**10000**
2	1	1	1	1	1	1	1	1	2	2	3	3	4	4	4
8	2	2	2	2	2	2	2	2	2	2	3	3	4	4	4
12	2	2	2	2	2	2	2	2	2	2	3	3	4	4	4
18	2	2	2	2	2	2	2	2	2	3	3	3	4	4	4
24	2	2	2	2	2	2	2	2	2	3	3	4	4	4	5
36	2	2	2	2	2	2	2	2	2	3	3	4	4	4	5
48	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
60	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
OTHERS															
SS	1	1	1	1	1	1	2	2	2	3	3	3	4	4	4
FPS								3	3	3	4	4	4	4	5

Source: ICF Consulting

The development drilling schedule is determined based on the assumed drilling capacity (maximum number of wells that could be drilled in a year). This drilling capacity varies by type of production facility and water depth. For a platform type production facility (FP, CT, or TLP), the development drilling capacity is also a function of the number of slots. The assumed drilling capacity by production facility type is shown in Table 3-7.

Production transportation/gathering system. It is assumed in the model that the installation of the gathering systems occurs during the first year of construction of the development structure and is completed within 1 year.

Production Operations

Production operations begin in the year after the construction of the structure is complete. The life of the production depends on the field size, water depth, and development strategy. First production is from delineation wells that were converted to production wells. Development drilling starts at the end of the production facility construction period.

Table 3-7. Development Drilling Capacity by Production Facility Type

Maximum Number of Wells Drilled (wells/platform/year, 1 rig)	
Drilling Depth (feet)	**Drilling Capacity (24 slots)**
0	24
6000	24
7000	24
8000	20
9000	20
10000	20
11000	20
12000	16
13000	16
14000	12
15000	8
16000	4
17000	2
18000	2
19000	2
20000	2
30000	2

Maximum Number of Wells Drilled (wells/field/year)			
Water Depth (feet)	**SS**	**FPS**	**FPSO**
0	4		4
1000	4		4
2000	4		4
3000	4	4	4
4000	4	4	4
5000	3	3	3
6000	2	2	2
7000	2	2	2
8000	1	1	1
9000	1	1	1
10000	1	1	1

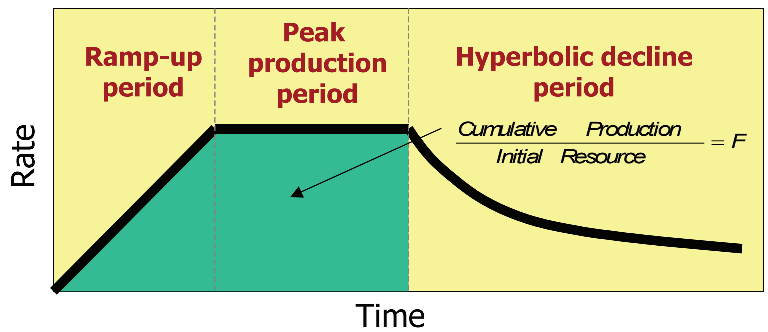
Source: ICF Consulting

Production profiles

The original hydrocarbon resource (in BOE) is divided between oil and natural gas using a user specified proportion. Due to the development drilling schedule, not all wells in the same field will produce at the same time. This yields a ramp-up profile in the early production period (Figure 3-3). The initial production rate is the same for all wells in the field and is constant for a period of time. Field production reaches its peak when all the wells have been drilled and start producing. The production will start to decline (at a user specified rate) when the ratio of cumulative production to initial resource equals a user specified fraction.

Gas (plus lease condensate) production is calculated based on gas resource, and oil (plus associated gas) production is calculated based on the oil resource. Lease condensate production is separated from the gas production using the user specified condensate yield. Likewise, associated-dissolved gas production is separated from the oil production using the user specified associated gas-to-oil ratio. Associated-dissolved gas production is then tracked separately from the nonassociated gas production throughout the projection. Lease condensate production is added to crude oil production and is not tracked separately.

Figure 3-3. Undiscovered Field Production Profile



Source: ICF Consulting

Field Abandonment

All wells in a field are assumed to be shut-in when the net revenue from the field is less than total State and Federal taxes. Net revenue is total revenue from production less royalties, operating costs, transportation costs, and severance taxes.

Discovered Undeveloped Fields Component

Announced discoveries that have not been brought into production by 2002 are included in this component of the OOGSS. The data required for these fields include location, field size class, gas percentage of BOE resource, condensate yield, gas to oil ratio, start year of production, initial production rate, fraction produced before decline, and hyperbolic decline parameters. The BOE resource for each field corresponds to the field size class as specified in Table 3-3.

The number of development wells is the same as that of an undiscovered field in the same water depth and of the same field size class (Equation 3-13). The production profile is also the same as that of an undiscovered field (Figure 3-3).

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2009 are shown in Table 3-8. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent is assumed to be gas.

Producing Fields Component

A separate database is used to track currently producing fields. The data required for each producing field include location, field size class, field type (oil or gas), total recoverable resources, historical production (1990-2002), and hyperbolic decline parameters.

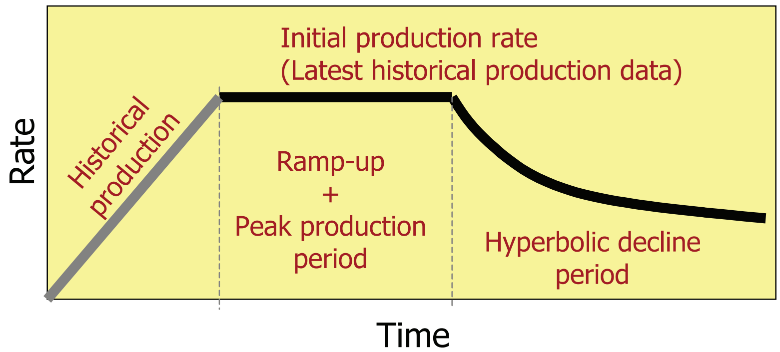
Projected production from the currently producing fields will continue to decline if, historically, production from the field is declining (Figure 3-4). Otherwise, production is held constant for a period of time equal to the sum of the specified number ramp-up years and number of years at peak production after which it will decline (Figure 3-5). The model assumes that production will decline according to a hyperbolic decline curve until the economic limit is achieved and the field is abandoned. Typical production profile data are shown in Table 3-9. Associated-dissolved gas and lease condensate production are determined the same way as in the undiscovered field component.

Table 3-8. Assumed Size and Initial Production Year of Major Announced Deepwater Discoveries

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBoe)	Start Year of Production
Great White	AC857	8717	2002	14	372	2010
Telemark	AT063	4457	2000	12	89	2010
Ozona	GB515	3000	2008	12	89	2011
West Tonga	GC726	4674	2007	12	89	2011
Gladden	MC800	3116	2008	12	89	2011
Pony	GC468	3497	2006	13	182	2013
Knotty Head	GC512	3557	2005	15	691	2013
Puma	GC823	4129	2003	14	372	2013
Big Foot	WR029	5235	2005	12	89	2013
Cascade	WR206	8143	2002	14	372	2013
Chinook	WR469	8831	2003	14	372	2013
Pyrenees	GB293	2100	2009	12	89	2014
Kaskida	KC292	5860	2006	15	691	2014
Appaloosa	MC503	2805	2008	14	372	2014
Jack	WR759	6963	2004	14	372	2014
Samurai	GC432	3400	2009	12	89	2015
Wide Berth	GC490	3700	2009	12	89	2015
Manny	MC199	2478	2010	13	182	2015
Kodiak	MC771	4986	2008	15	691	2015
St. Malo	WR678	7036	2003	14	372	2015
Mission Deep	GC955	7300	2006	13	182	2016
Tiber	KC102	4132	2009	16	1419	2016
Vito	MC984	4038	2009	13	182	2016
Stones	WR508	9556	2005	12	89	2016
Heidelberg	GB859	5000	2009	13	182	2017
Freedom	MC948	6095	2008	15	691	2017
Shenandoah	WR052	5750	2009	13	182	2017
Buckskin	KC872	6920	2009	13	182	2018
Julia	WR627	7087	2007	12	89	2018
Vicksburg	DC353	7457	2009	14	372	2019
Lucius	KC875	7168	2009	13	182	2019

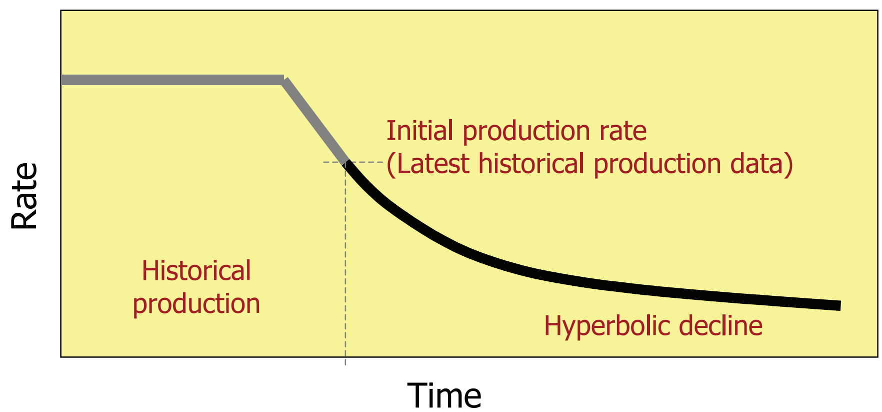
Source: U.S. Energy Information Administration, Energy Analysis, Office of Petroleum, Gas, and Biofuels Analysis

Figure 3-4. Production Profile for Producing Fields - Constant Production Case



Source: ICF Consulting

Figure 3-5. Production Profile for Producing Fields - Declining Production Case



Source: ICF Consulting

Table 3-9. Production Profile Data for Oil & Gas Producing Fields

Region	Crude Oil						Natural Gas					
	FSC 2 - 10			FSC 11 – 17			FSC 2 - 10			FSC 11 - 17		
	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate
Shallow GOM	2	2	0.15	3	3	0.10	2	1	0.20	3	2	0.10
Deep GOM	2	2	0.20	2	3	0.15	2	2	0.25	3	2	0.20
Atlantic	2	2	0.20	3	3	0.20	2	1	0.25	3	2	0.20
Pacific	2	2	0.10	3	2	0.10	2	1	0.20	3	2	0.20

FSC = Field Size Class
Source: ICF Consulting

Generation of Supply Curves

As mentioned earlier, the OOGSS does not determine the actual volume of crude oil and nonassociated natural gas produced in a given projection year but rather provides the parameters for the short-term supply functions used to determine regional supply and demand market equilibration. For each year, t, and offshore region, r, the OGSM calculates the stock of proved reserves at the beginning of year t+1 and the expected production-to-reserves (PR) ratio for year t+1 as follows.

The volume of proved reserves in any year is calculated as

$$RESOFF_{r,k,t+1} = RESOFF_{r,k,t} - PRDOFF_{r,k,t} + NRDOFF_{r,k,t} + REVOFF_{r,k,t} \tag{3-17}$$

where

RESOFF	=	beginning- of-year reserves
PRDOFF	=	production
NRDOFF	=	new reserve discoveries
REVOFF	=	reserve extensions, revisions, and adjustments
r	=	region (1=Atlantic, 2=Pacific, 3=GOM)
k	=	fuel type (1=oil; 2=nonassociated gas)
t	=	year.

Expected production, EXPRDOFF, is the sum of the field level production determined in the undiscovered fields component, the discovered, undeveloped fields component, and the producing field component. The volume of crude oil production (including lease condensate), PRDOFF, passed to the PMM is equal to EXPRDOFF. Nonassociated natural gas production in year t is the market equilibrated volume passed to the OGSM from the NGTDM.

Reserves are added through new field discoveries as well as delineation and developmental drilling. Each newly discovered field not only adds proved reserves but also a much larger amount of inferred reserves. The allocation between proved and inferred reserves is based on historical reserves growth statistics provided by the Minerals Management Service. Specifically,

$$NRDOFF_{r,k,t} = NFDISC_{r,k,t-1} * \left(\frac{1}{RSVGRO_k} \right) \tag{3-18}$$

$$NIRDOFF_{r,k,t} = NFDISC_{r,k,t-1} * \left(1 - \frac{1}{RSVGRO_k} \right) \tag{3-19}$$

where

NRDOFF	=	new reserve discovery
NIRDOFF	=	new inferred reserve additions
NFDISC	=	new field discoveries
RSVGRO	=	reserves growth factor (8.2738 for oil and 5.9612 for gas)
r	=	region (1=Atlantic, 2=Pacific, 3=GOM)
k	=	fuel type (1=oil; 2=gas)

t = year.

Reserves are converted from inferred to proved with the drilling of other exploratory (or delineation) wells and developmental wells. Since the expected offshore PR ratio is assumed to remain constant at the last historical value, the reserves needed to support the total expected production, EXPRDOFF, can be calculated by dividing EXPRDOFF by the PR ratio. Solving Equation 3-1 for $REVOFF_{r,k,t}$ and writing

gives

$$REVOFF_{r,k,t} = \frac{EXPRDOFF_{r,k,t+1}}{PR_{r,k}} + PRDOFF_{r,k,t} - RESOFF_{r,k,t} - NRDOFF_{r,k,t} \tag{3-20}$$

The remaining proved reserves, inferred reserves, and undiscovered resources are tracked throughout the projection period to ensure that production from offshore sources does not exceed the assumed resource base. Field level associated-dissolved gas is summed to the regional level and passed to the NGTDM.

Advanced Technology Impacts

Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a profound impact on the costs associated with these activities. The OOGSS has been designed to give due consideration to the effect of advances in technology that may occur in the future. The specific technology levers and values are presented in Table 3-10.

Table 3-10. Offshore Exploration and Production Technology Levers

Technology Lever	Total Improvement (percent)	Number of Years
Exploration success rates	30	30
Delay to commence first exploration and between exploration	15	30
Exploration & development drilling costs	30	30
Operating cost	30	30
Time to construct production facility	15	30
Production facility construction costs	30	30
Initial constant production rate	15	30
Decline rate	0	30

Source: ICF Consulting

Appendix 3.A. Offshore Data Inventory

VARIABLES				
Variable Name				
Code	Text	Description	Unit	Classification
ADVLTXOFF	PRODTAX	Offshore ad valorem tax rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CPRDOFF	COPRD	Offshore coproduct rate	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CUMDISC	DiscoveredFields	Cumulative number of dicovered offshore fields	NA	Offshore evaluation unit: Field size class
CUMNFW	CumNFW	Cumulative number of new fields wildcats drilled	NA	Offshore evaluation unit: Field size class
CURPRROFF	omega	Offshore initial P/R ratios	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CURRESOFF	R	Offshore initial reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
DECLOFF	--	Offshore decline rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
DEVLCOST	DevelopmentDrilling Cost	Development drilling cost	$ per well	Offshore evaluation unit
DRILLOFF	DRILL	Offshore drilling cost	1987$	4 Lower 48 offshore subregions
DRYOFF	DRY	Offshore dry hole cost	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions
DVWELLOFF	--	Offshore development project drilling schedules	wells per year	4 Lower 48 offshore subregions; Fuel (oil, gas)
ELASTOFF	--	Offshore production elasticity values	Fraction	4 Lower 48 offshore subregions
EXPLCOST	ExplorationDrillingC osts	Exploration well drilling cost	$ per wells	Offshore evaluation unit
EXWELLOFF	--	Offshore exploratory project drilling schedules	wells per year	4 Lower 48 offshore subregions
FLOWOFF	--	Offshore flow rates	bls, MCF per year	4 Lower 48 offshore subregions; Fuel (oil, gas)
FRMINOFF	FRMIN	Offshore minimum exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR1OFF	FR1	Offshore new field wildcat well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR2OFF	FR3	Offshore developmental well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR3OFF	FR2	Offshore other exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
HISTPRROFF	--	Offshore historical P/R ratios	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
HISTRESOFF	--	Offshore historical beginning-of-year reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
INFRSVOFF	I	Offshore inferred reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
KAPFRCOFF	EXKAP	Offshore drill costs that are tangible & must be depreciated	fraction	Class (exploratory, developmental)
KAPSPNDOFF	KAP	Offshore other capital expenditures	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions
LEASOFF	EQUIP	Offshore lease equipment cost	1987$ per project	Class (exploratory, developmental); 4 Lower 48 offshore subregions
NDEVWLS	DevelopmentWells	Number of development wells drilled	NA	Offshore evaluation unit
NFWCOSTOFF	COSTEXP	Offshore new field wildcat cost	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions

VARIABLES				
Variable Name				
Code	Text	Description	Unit	Classification
NFWELLOFF	--	Offshore exploratory and developmental project drilling schedules	wells per project per year	Class (exploratory, developmental); r=1
NIRDOFF	NIRDOFF	Offshore new inferred reserves	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
NRDOFF	NRDOFF	Offshore new reserve discoveries	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
OPEROFF	OPCOST	Offshore operating cost	1987$ per well per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions
OPRCOST	OperatingCost	Operating cost	$ per well	Offshore evaluation unit
PFCOST	StructureCost	Offshore production facility cost	$ per structure	Offshore evaluation unit
PRJOFF	N	Offshore project life	Years	Fuel (oil, gas)
RCPRDOFF	M	Offshore recovery period intangible & tangible drill cost	Years	Lower 48 Offshore
RESOFF	RESOFF	Offshore reserves	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
REVOFF	REVOFF	Offshore reserve revisions	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
SC	Γ	Search coefficient for discovery model	Fraction	Offshore evaluation unit: Field size class
SEVTXOFF	PRODTAX	Offshore severance tax rates	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
SROFF	SR	Offshore drilling success rates	fraction	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
STTXOFF	STRT	State tax rates	fraction	4 Lower 48 offshore subregions
TECHOFF	TECH	Offshore technology factors applied to costs	fraction	Lower 48 Offshore
TRANSOFF	TRANS	Offshore expected transportation costs	NA	4 Lower 48 offshore subregions; Fuel (oil, gas)
UNRESOFF	Q	Offshore undiscovered resources	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
WDCFOFFIRKLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
WDCFOFFIRLAG	--	1989 offshore regional exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions;
WDCFOFFLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental)
WELLAGOFF	WELLSOFF	1989 offshore wells drilled	Wells per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
XDCKAPOFF	XDCKAP	Offshore intangible drill costs that must be depreciated	fraction	NA

PARAMETERS		
Parameter	Description	Value
nREG	Region ID (1: CENTRAL & WESTERN GOM; 2: EASTERN GOM; 3: ATLANTIC; 4: PACIFIC)	4
nPA	Planning Area ID (1: WESTERN GOM; 2: CENTRAL GOM; 3: EASTERN GOM; 4: NORTH ATLANTIC; 5: MID ATLANTIC; 6: SOUTH ATLANTIC; 7: FLORIDA STRAITS; 8: PACIFIC; NORTHWEST; 9: CENTRAL CALIFORNIA; 10: SANTA BARBARA - VENTURA BASIN; 11: LOS ANGELES BASIN; 12: INNER BORDERLAND; 13: OUTER BORDERLAND)	13
ntEU	Total number of evaluation units (43)	43
nMaxEU	Maximum number of EU in a PA (6)	6
TOTFLD	Total number of evaluation units	3600
nANN	Total number of announce discoveries	127

PARAMETERS		
Parameter	**Description**	**Value**
nPRD	Total number of producing fields	1132
nRIGTYP	Rig Type (1: JACK-UP 0-1500; 2: JACK-UP 0-1500 (Deep Drilling); 3: SUBMERSIBLE 0-1500; 4: SEMI-SUBMERSIBLE 1500-5000; 5: SEMI-SUBMERSIBLE 5000-7500; 6: SEMI-SUBMERSIBLE 7500-10000; 7: DRILL SHIP 5000-7500; 8: DRILL SHIP 7500-10000)	8
nPFTYP	Production facility type (1: FIXED PLATFORM (FP); 2: COMPLIANT TOWER (CT); 3: TENSION LEG PLATFORM (TLP); 4: FLOATING PRODUCTION SYSTEM (FPS); 5: SPAR; 6: FLOATING PRODUCTION STORAGE & OFFLOADING (FPSO); 7: SUBSEA SYSTEM (SS))	7
nPFWDR	Production facility water depth range (1: 0 - 656 FEET; 2: 656 - 2625 FEET; 3: 2625 - 5249 FEET; 4: 5249 - 7874 FEET; 5: 7874 - 9000 FEET)	5
NSLTIdx	Number of platform slot data points	8
NPFWD	Number of production facility water depth data points	15
NPLTDD	Number of platform water depth data points	17
NOPFWD	Number of other production facitlity water depth data points	11
NCSTWD	Number of water depth data points for production facility costs	39
NDRLWD	Number of water depth data points for well costs	15
NWLDEP	Number of well depth data points	30
TRNPPLNCSTNDIAM	Number of pipeline diameter data points	19
MAXNFIELDS	Maximum number of fields for a project/prospect	10
nMAXPRJ	Maximum number of projects to evaluate per year	500
PRJLIFE	Maximum project life in years	10

INPUT DATA			
Variable	**Description**	**Unit**	**Source**
ann_EU	Announced discoveries - Evaluation unit name	-	PGBA
ann_FAC	Announced discoveries - Type of production facility	-	BOEMRE
ann_FN	Announced discoveries - Field name	-	PGBA
ann_FSC	Announced discoveries - Field size class	integer	BOEMRE
ann_OG	Announced discoveries - fuel type	-	BOEMRE
ann_PRDSTYR	Announced discoveries - Start year of production	integer	BOEMRE
ann_WD	Announced discoveries - Water depth	feet	BOEMRE
ann_WL	Announced discoveries - Number of wells	integer	BOEMRE
ann_YRDISC	Announced discoveries - Year of discovery	integer	BOEMRE
beg_rsva	AD gas reserves	bcf	calculated in model
BOEtoMcf	BOE to Mcf conversion	Mcf/BOE	ICF
chgDrlCstOil	Change of Drilling Costs as a Function of Oil Prices	fraction	ICF
chgOpCstOil	Change of Operating Costs as a Function of Oil Prices	fraction	ICF
chgPFCstOil	Change of Production facility Costs as a Function of Oil Prices	fraction	ICF
cndYld	Condensate yield by PA, EU	Bbl/mmcf	BOEMRE
cstCap	Cost of capital	percent	BOEMRE
dDpth	Drilling depth by PA, EU, FSC	feet	BOEMRE
deprSch	Depreciation schedule (8 year schedule)	fraction	BOEMRE
devCmplCst	Completion costs by region, completion type (1=Single, 2=Dual), water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index	million 2003 dollars	BOEMRE
devDrlCst	Mean development well drilling costs by region, water depth index, drilling depth index	million 2003 dollars	BOEMRE
devDrlDly24	Maximum number of development wells drilled from a 24-slot PF by drilling depth index	Wells/PF/year	ICF
devDrlDlyOth	Maximum number of development wells drilled for other PF by PF type, water depth index	Wells/field/year	ICF

INPUT DATA			
Variable	Description	Unit	Source
devOprCst	Operating costs by region, water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index	2003 $/well/year	BOEMRE
devTangFrc	Development Wells Tangible Fraction	fraction	ICF
dNRR	Number of discovered producing fields by PA, EU, FSC	integer	BOEMRE
Drillcap	Drilling Capacity	wells/year/rig	ICF
duNRR	Number of discovered/undeveloped fields by PA, EU, FSC	integer	ICF
EUID	Evaluation unit ID	integer	ICF
EUname	Names of evaluation units by PA	integer	ICF
EUPA	Evaluation unit to planning area x-walk by EU_Total	integer	ICF
exp1stDly	Delay before commencing first exploration by PA, EU	number of years	ICF
exp2ndDly	Total time (Years) to explore and appraise a field by PA, EU	number of years	ICF
expDrlCst	Mean Exploratory Well Costs by region, water depth index, drilling depth index	million 2003 dollars	BOEMRE
expDrlDays	Drilling days/well by rig type	number of days/well	ICF
expSucRate	Exploration success rate by PA, EU, FSC	fraction	ICF
ExpTangFrc	Exploration and Delineation Wells Tangible Fraction	fraction	ICF
fedTaxRate	Federal Tax Rate	percent	ICF
fldExpRate	Maximum Field Exploration Rate	percent	ICF
gasprice	Gas wellhead price by region	2003$/mcf	NGTDM
gasSevTaxPrd	Gas production severance tax	2003$/mcf	ICF
gasSevTaxRate	Gas severance tax rate	percent	ICF
GOprop	Gas proportion of hydrocarbon resource by PA, EU	fraction	ICF
GOR	Gas-to-Oil ratio (Scf/Bbl) by PA, EU	Scf/Bbl	ICF
GORCutOff	GOR cutoff for oil/gas field determination	-	ICF
gRGCGF	Gas Cumulative Growth Factor (CGF) for gas reserve growth calculation by year index	-	BOEMRE
levDelWls	Exploration drilling technology (reduces number of delineation wells to justify development	percent	PGBA
levDrlCst	Drilling costs R&D impact (reduces exploration and development drilling costs)	percent	PGBA
levExpDly	Pricing impact on drilling delays (reduces delays to commence first exploration and between exploration	percent	PGBA
levExpSucRate	Seismic technology (increase exploration success rate)	percent	PGBA
levOprCst	Operating costs R&D impact (reduces operating costs)	percent	PGBA
levPfCst	Production facility cost R&D impact (reduces production facility construction costs	percent	PGBA
levPfDly	Production facility design, fabrication and installation technology (reduces time to construct production facility)	percent	PGBA
levPrdPerf1	Completion technology 1 (increases initial constant production facility)	percent	PGBA
levPrdPerf2	Completion technology 2 (reduces decile rates)	percent	PGBA
nDelWls	Number of delineation wells to justify a production facility by PA, EU, FSC	integer	ICF
nDevWls	Maximum number of development wells by PA, EU, FSC	integer	ICF
nEU	Number of evaluation units in each PA	integer	ICF
nmEU	Names of evaluation units by PA	-	ICF
nmPA	Names of planning areas by PA	-	ICF
nmPF	Name of production facility and subsea-system by PF type index	-	ICF
nmReg	Names of regions by region	-	ICF
ndiroff	Additions to inferred reserves by region and fuel type	oil: MBbls; gas: Bcf	calculated in model
nrdoff	New reserve discoveries by region and fuel type	oil: Mbbls; gas: Bcf	calculated in model
nRigs	Number of rigs by rig type	integer	ICF

INPUT DATA			
Variable	Description	Unit	Source
nRigWlsCap	Number of well drilling capacity (Wells/Rig)	wells/rig	ICF
nRigWlsUtl	Number of wells drilled (Wells/Rig)	wells/rig	ICF
nSlt	Number of slots by # of slots index	integer	ICF
oilPrcCstTbl	Oil price for cost tables	2003$/Bbl	ICF
oilprice	Oil wellhead price by region	2003$/Bbl	PMM
oilSevTaxPrd	Oil production severance tax	2003$/Bbl	ICF
oilSevTaxRate	Oil severance tax rate	percent	ICF
oRGCGF	Oil Cumulative Growth Factor (CGF) for oil reserve growth calculation by year index	fraction	BOEMRE
paid	Planning area ID	integer	ICF
PAname	Names of planning areas by PA	-	ICF
pfBldDly1	Delay for production facility design, fabrication, and installation (by water depth index, PF type index, # of slots index (0 for non platform)	number of years	ICF
pfBldDly2	Delay between production facility construction by water depth index	number of years	ICF
pfCst	Mean Production Facility Costs in by region, PF type, water depth index, # of slots index (0 for non-platform)	million 2003 $	BOEMRE
pfCstFrc	Production facility cost fraction matrix by year index, year index	fraction	ICF
pfMaxNFld	Maximum number of fields in a project by project option	integer	ICF
pfMaxNWls	Maximum number of wells sharing a flowline by project option	integer	ICF
pfMinNFld	Minimum number of fields in a project by project option	integer	ICF
pfOptFlg	Production facility option flag by water depth range index, FSC	-	ICF
pfTangFrc	Production Facility Tangible Fraction	fraction	ICF
pfTypFlg	Production facility type flag by water depth range index, PF type index	-	ICF
platform	Flag for platform production facility	-	ICF
prd_DEPTH	Producing fields - Total drilling depth	feet	BOEMRE
prd_EU	Producing fields - Evaluation unit name	-	ICF
prd_FLAG	Producing fields - Production decline flag	-	ICF
prd_FN	Producing fields - Field name	-	BOEMRE
prd_ID	Producing fields - BOEMRE field ID	-	BOEMRE
prd_OG	Producing fields - Fuel type	-	BOEMRE
prd_YRDISC	Producing fields - Year of discovery	year	BOEMRE
prdDGasDecRatei	Initial gas decline rate by PA, EU, FSC range index	fraction/year	ICF
prdDGasHyp	Gas hyperbolic decline coefficient by PA, EU, FSC range index	fraction	ICF
prdDOilDecRatei	Initial oil decline rate by PA, EU,	fraction/year	ICF
prdDOilHyp	Oil hyperbolic decline coefficient by PA, EU, FSC range index	fraction	ICF
prdDYrPeakGas	Years at peak production for gas by PA, EU, FSC, range index	number of years	ICF
prdDYrPeakOil	Years at peak production for oil by PA, EU, FSC, range index	number of years	ICF
prdDYrRampUpGas	Years to ramp up for gas production by PA, EU, FSC range index	number of years	ICF
prdDYrRampUpOil	Years to ramp up for oil production by PA, EU, FSC range index	number of years	ICF
prdGasDecRatei	Initial gas decline rate by PA, EU	fraction/year	ICF
prdGasFrc	Fraction of gas produced before decline by PA, EU	fraction	ICF
prdGasHyp	Gas hyperbolic decline coefficient by PA, EU	fraction	ICF
prdGasRatei	Initial gas production (Mcf/Day/Well) by PA, EU	Mcf/day/well	ICF
PR	Expected production to reserves ratio by fuel typ	fraction	PGBA
prdoff	Expected production by fuel type	oil:MBbls; gas: Bcf	calculated in model
prdOilDecRatei	Initial oil decline rate by PA, EU	fraction/year	ICF
prdOilFrc	Fraction of oil produced before decline by PA, EU	fraction	ICF

INPUT DATA			
Variable	**Description**	**Unit**	**Source**
prdOilHyp	Oil hyperbolic decline coefficient by PA, EU	fraction	ICF
prdOilRatei	Initial oil production (Bbl/Day/Well) by PA, EU	Bbl/day/well	ICF
prod	Producing fields - annual production by fuel type	oil:MBbls; gas:Mmcf	BOEMRE
prod_asg	AD gas production	bcf	calculated in model
revoff	Extensions, revisions, and adjustments by fuel type	oil:MBbls; gas:Bcf	
rigBldRatMax	Maximum Rig Build Rate by rig type	percent	ICF
rigIncrMin	Minimum Rig Increment by rig type	integer	ICF
RigUtil	Number of wells drilled	wells/rig	ICF
rigUtilTarget	Target Rig Utilization by rig type	percent	ICF
royRateD	Royalty rate for discovered fields by PA, EU, FSC	fraction	BOEMRE
royRateU	Royalty rate for undiscovered fields by PA, EU, FSC	fraction	BOEMRE
stTaxRate	Federal Tax Rate by PA, EU	percent	ICF
trnFlowLineLen	Flowline length by PA, EU	Miles/prospect	ICF
trnPpDiam	Oil pipeline diameter by PA, EU	inches	ICF
trnPplnCst	Pipeline cost by region, pipe diameter index, water depth index	million 2003 $/mile	BOEMRE
trnTrfGas	Gas pipeline tariff ($/Mcf) by PA, EU	2003 $/Bbl	ICF
trnTrfOil	Oil pipeline tariff ($/Bbl) by PA, EU	2003 $/Bbl	ICF
uNRR	Number of undiscovered fields by PA, EU, FSC	integer	calculated in model
vMax	Maximum MMBOE of FSC	MMBOE	BOEMRE
vMean	Geometric mean MMBOE of FSC	MMBOE	BOEMRE
vMin	Minimum MMBOE of FSC	MMBOE	BOEMRE
wDpth	Water depth by PA, EU, FSC	feet	BOEMRE
yrAvl	Year lease available by PA, EU	year	ICF
yrCstTbl	Year of cost tables	year	ICF
Sources: BOEMRE = Bureau of Ocean Energy Management, Regulation, and Enforcement (formerly the Minerals Management Service); ICF = ICF Consulting; PGBA = EIA, Office of Petroleum, Gas, and Biofuels Analysis			

4. Alaska Oil and Gas Supply Submodule

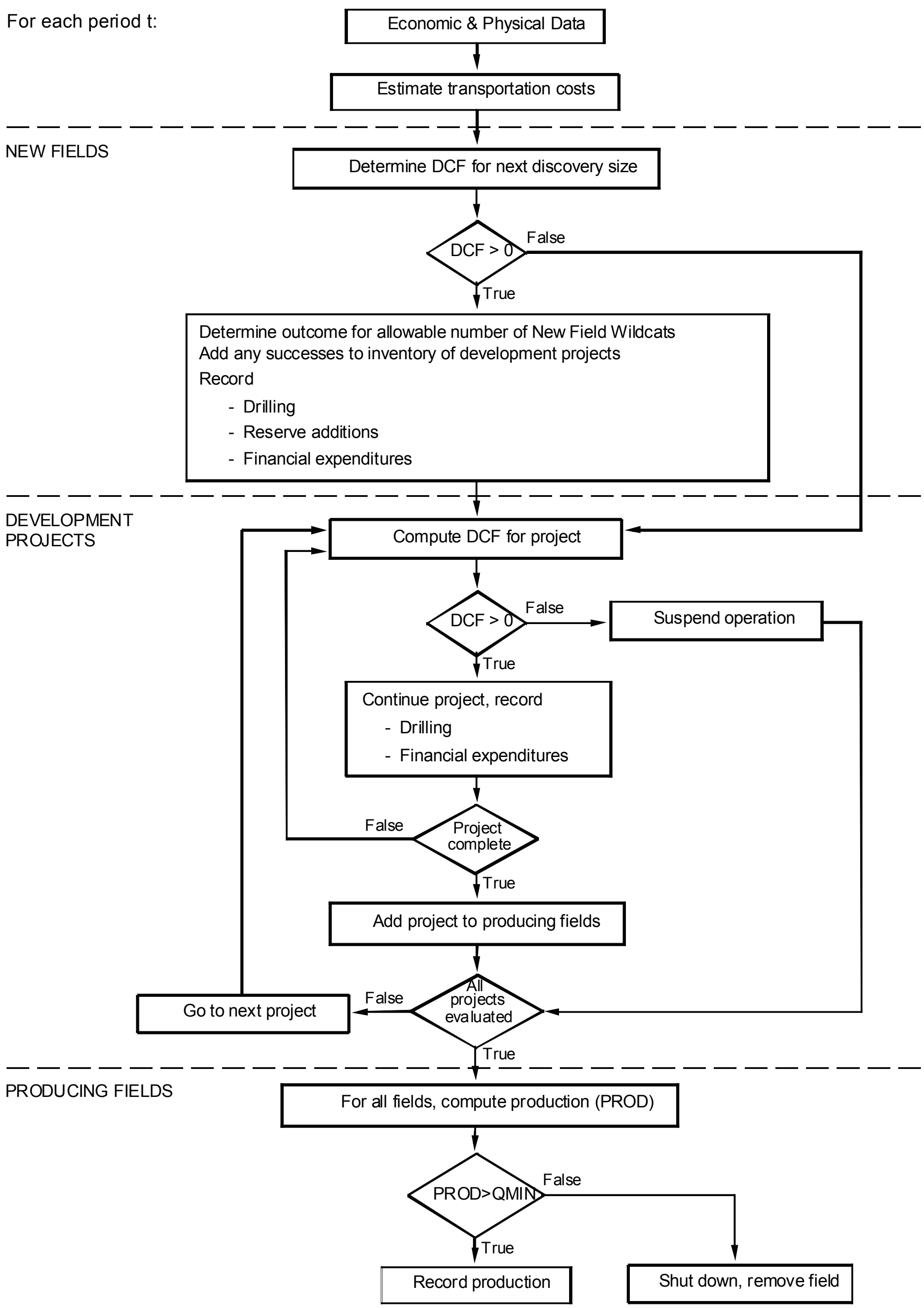
This section describes the structure for the Alaska Oil and Gas Supply Submodule (AOGSS). The AOGSS is designed to project field-specific oil production from the Onshore North Slope, Offshore North Slope, and Other Alaska areas (primarily the Cook Inlet area). The North Slope region encompasses the National Petroleum Reserve Alaska in the west, the State Lands in the middle, and the Arctic National Wildlife Refuge area in the east. This section provides an overview of the basic modeling approach, including a discussion of the discounted cash flow (DCF) method.

Alaska natural gas production is not projected by the AOGSS, but by Natural Gas Transmission and Distribution Module (NGTDM). The NGTDM projects Alaska gas consumption and whether an Alaska gas pipeline is projected to be built to carry Alaska North Slope gas into Canada and U.S. gas markets. As of January 1, 2009, Alaska was estimated to have 7.7 trillion cubic feet of proved reserves, 24.8 trillion cubic feet of inferred resources at existing fields (also known as field appreciation), and 257.5 trillion cubic feet of undiscovered resources, excluding the Arctic National Wildlife Refuge undiscovered gas resources. Over the long term, Alaska natural gas production is determined by and constrained by local consumption and by the capacity of a gas pipeline that might be built to serve Canada and U.S. lower-48 markets. The proven and inferred gas resources alone (i.e. 32.5 trillion cubic feet), plus known but undeveloped resources, are sufficient to satisfy at least 20 years of Alaska gas consumption and gas pipeline throughput. Moreover, large deposits of natural gas have been discovered (e.g., Point Thomson) but remain undeveloped due to a lack of access to gas consumption markets. Because Alaska natural gas production is best determined by projecting Alaska gas consumption and whether a gas pipeline is put into operation, the AOGSS does not attempt to project new gas field discoveries and their development or the declining production from existing fields.

AOGSS Overview

The AOGSS solely focuses on projecting the exploration and development of undiscovered oil resources, primarily with respect to the oil resources expected to be found onshore and offshore in North Alaska. The AOGSS is divided into three components: new field discoveries, development projects, and producing fields (Figure 4-1). Transportation costs are used in conjunction with the crude oil price to Southern California refineries to calculate an estimated wellhead (netback) oil price. A discounted cash flow (DCF) calculation is used to determine the economic viability of Alaskan drilling and production activities. Oil field investment decisions are modeled on the basis of discrete projects. The exploration, discovery, and development of new oil fields depend on the expected exploration success rate and new field profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, along with historical production patterns and announced plans for currently producing fields.

Figure 4-1. Flowchart of the Alaska Oil and Gas Supply Submodule



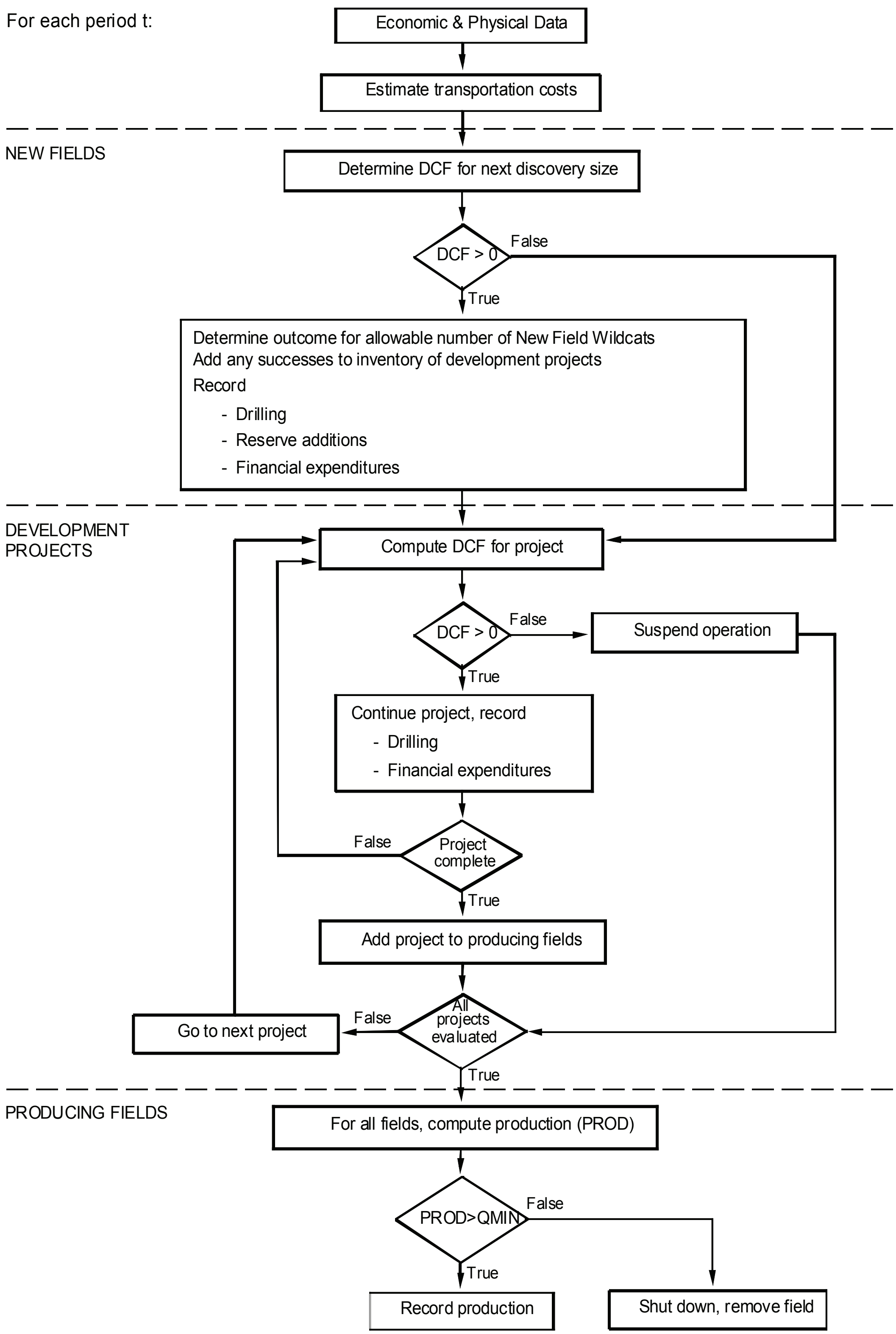
Calculation of Costs

Costs differ within the model for successful wells and dry holes. Costs are categorized functionally within the model as

- Drilling costs,
- Lease equipment costs, and
- Operating costs (including production facilities and general and administrative costs).

All costs in the model incorporate the estimated impact of environmental compliance. Environmental regulations that preclude a supply activity outright are reflected in other adjustments to the model. For example, environmental regulations that preclude drilling in certain locations within a region are modeled by reducing the recoverable resource estimates for that region.

Each cost function includes a variable that reflects the cost savings associated with technological improvements. As a result of technological improvements, average costs decline in real terms



relative to what they would otherwise be. The degree of technological improvement is a user specified option in the model. The equations used to estimate costs are similar to those used for the lower 48 but include cost elements that are specific to Alaska. For example, lease equipment includes gravel pads and ice roads.

Drilling Costs

Drilling costs are the expenditures incurred for drilling both successful wells and dry holes, and for equipping successful wells through the "Christmas tree," the valves and fittings assembled at the top of a well to control the fluid flow. Elements included in drilling costs are labor, material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. Drilling costs for exploratory wells include costs of support equipment such as ice pads. Lease equipment required for production is included as a separate cost calculation and covers equipment installed on the lease downstream from the Christmas tree.

The average cost of drilling a well in any field located within region r in year t is given by:

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1) ** (t - T_b) \tag{4-1}$$

where

i	=	well class (exploratory=1, developmental=2)
r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k	=	fuel type (oil=1, gas=2 - but not used)
t	=	forecast year
DRILLCOST	=	drilling costs
T_b	=	base year of the forecast
TECH1	=	annual decline in drilling costs due to improved technology.

The above function specifies that drilling costs decline at the annual rate specified by TECH1. Drilling costs are not modeled as a function of the drilling rig activity level as they are in the Onshore Lower 48 methodology. Drilling rigs and equipment are designed specifically for the harsh Arctic weather conditions. Once drilling rigs are moved up to Alaska and reconfigured for Arctic conditions, they typically remain in Alaska. Company drilling programs in Alaska are planned to operate at a relatively constant level of activity because of the limited number of drilling rigs and equipment available for use. Most Alaska oil rig activity pertains to drilling in-fill wells intended to slow the rate of production decline in the largest Alaska oil fields.

For the *Annual Energy Outlook 2011*, Alaska onshore and offshore drilling and completion costs were updated based on the American Petroleum Institute’s (API), *2007 Joint Association Survey on Drilling Costs*, dated December 2008. Based on these API drilling and completion costs and earlier work performed by Advanced Resources International, Inc. in 2002, the following oil well drilling and completion costs were incorporated into the AOGSS database (Table 4.1).

Table 4.1
AOGSS Oil Well Drilling and Completion Costs
By Location and Category
In millions of 2007 dollars

	New Field Wildcat Wells	New Exploration Wells	Developmental Wells
	In millions of 2007 dollars		
Offshore North Slope	206	103	98
Onshore North Slope	150	75	57
South Alaska	73	59	37
	In millions of 1990 dollars		
Offshore North Slope	140	70	67
Onshore North Slope	102	51	39
South Alaska	50	40	25

Table 1 provides both 1990 and 2007 well drilling and completion cost data because the former are used within the context of calculating AOGSS discounted cash flows, while the latter are comparable to the current price environment.

Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a developed lease. Costs include: producing equipment, the gathering system, processing equipment (e.g., oil/gas/water separation), and production related infrastructure such as gravel pads. Producing equipment costs include tubing, pumping equipment. Gathering system costs consist of flowlines and manifolds. The lease equipment cost estimate for a new oil well is given by:

$$EQUIP_{r,k,t} = EQUIP_{r,k,t} * (1 - TECH2)^{r - T_b} \tag{4-2}$$

where

r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k	=	fuel type (oil=1, gas=2 – not used)
t	=	forecast year
EQUIP	=	lease equipment costs
T_b	=	base year of the forecast
TECH2	=	annual decline in lease equipment costs due to improved technology.

Operating Costs

EIA operating cost data, which are reported on a per well basis for each region, include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

The estimated operating cost curve is:

$$OPCOST_{r,k,t} = OPCOST_{r,k,t} * (1 - TECH2)^{r - T_b} \tag{4-3}$$

where

r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k	=	fuel type (oil=1, gas=2 – not used)
t	=	forecast year
OPCOST	=	operating cost
T_b	=	base year of the forecast
TECH3	=	annual decline in operating costs due to improved technology.

Drilling costs, lease equipment costs, and operating costs are integral components of the following discounted cash flow analysis. These costs are assumed to be uniform across all fields within each of the three Alaskan regions.

Treatment of Costs in the Model for Income Tax Purposes

All costs are treated for income tax purposes as either expensed or capitalized. The tax treatment in the DCF reflects the applicable provisions for oil producers. The DCF assumptions are consistent with standard accounting methods and with assumptions used in similar modeling efforts. The following assumptions, reflecting current tax law, are used in the calculation of costs.

- All dry-hole costs are expensed.
- A portion of drilling costs for successful wells is expensed. The specific split between expensing and amortization is based on the tax code.
- Operating costs are expensed.
- All remaining successful field development costs are capitalized.
- The depletion allowance for tax purposes is not included in the model, because the current regulatory limitations for invoking this tax advantage are so restrictive as to be insignificant in the aggregate for future drilling decisions.

- Successful versus dry-hole cost estimates are based on historical success rates of successful versus dry-hole footage.

- Lease equipment for existing wells is in place before the first forecast year of the model.

Discounted Cash Flow Analysis

A discounted cash flow (DCF) calculation is used to determine the profitability of oil projects.[1] A positive DCF is necessary to initiate the development of a discovered oil field. With all else being equal, large oil fields are more profitable to develop than small and mid-size fields. In Alaska, where developing new oil fields is quite expensive, particularly in the Arctic, the profitable development of small and mid-size oil fields is generally contingent on the pre-existence of infrastructure that was paid for by the development of a nearby large field. Consequently, AOGSS assumes that the largest oil fields will be developed first, followed by the development of ever smaller oil fields. Whether these oil fields are developed, regardless of their size, is projected on the basis of the profitability index, which is measured as the ratio of the expected discounted cash flow to expected capital costs for a potential project.

A key variable in the DCF calculation is the oil transportation cost to southern California refineries. Transportation costs for Alaskan oil include both pipeline and tanker shipment costs. The oil transportation cost directly affects the expected revenues from the production of a field as follows:[2]

$$REV_{f,t} = Q_{f,t} * (MP_t - TRANS_t) \qquad (4\text{-}4)$$

where

f	=	field
t	=	year
REV	=	expected revenues
Q	=	expected production volumes
MP	=	market price in the lower 48 states
TRANS	=	transportation cost.

The expected discounted cash flow associated with a potential oil project in field f at time t is given by

$$\begin{aligned} DCF_{f,t} = (&PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP \\ &- PVOPCOST - PVPRODTAX - PVSIT - PVFIT)_{f,t} \end{aligned} \qquad (4\text{-}5)$$

where,

PVREV	=	present value of expected revenues

[1]See Appendix 3.A at the end of this chapter for a detailed discussion of the DCF methodology.

[2]This formulation assumes oil production only. It can be easily expanded to incorporate the sale of natural gas.

PVROY	=	present value of expected royalty payments
PVDRILLCOST	=	present value of all exploratory and developmental drilling expenditures
PVEQUIP	=	present value of expected lease equipment costs
TRANSCAP	=	cost of incremental transportation capacity
PVOPCOST	=	present value of operating costs
PVPRODTAX	=	present value of expected production taxes (ad valorem and severance taxes)
PVSIT	=	present value of expected state corporate income taxes
PVFIT	=	present value of expected federal corporate income taxes

The expected capital costs for the proposed field f located in region r are:

$$COST_{f,t} = (PVEXPCOST + PVDEVCOST + PVEQUIP + TRANSCAP)_{f,t} \tag{4-6}$$

where

PVEXPCOST	=	present value exploratory drilling costs
PVDEVCOST	=	present value developmental drilling costs
PVEQUIP	=	present value lease equipment costs
TRANSCAP	=	cost of incremental transportation capacity

The profitability indicator from developing the proposed field is therefore

$$PROF_{f,t} = \frac{DCF_{f,t}}{COST_{f,t}} \tag{4-7}$$

The model assumes that field with the highest positive PROF in time t is eligible for exploratory drilling in the same year. The profitability indices for Alaska also are passed to the basic framework module of the OGSM.

New Field Discovery

Development of estimated recoverable resources, which are expected to be in currently undiscovered fields, depends on the schedule for the conversion of resources from unproved to reserve status. The conversion of resources into field reserves requires both a successful new field wildcat well and a positive discounted cash flow of the costs relative to the revenues. The discovery procedure can be determined endogenously, based on exogenously determined data. The procedure requires the following exogenously determined data:

- new field wildcat success rate,
- any restrictions on the timing of drilling,
- the distribution of technically recoverable field sizes within each region.

The endogenous procedure generates:

- the new field wildcat wells drilled in any year,
- the set of individual fields to be discovered, specified with respect to size and location (relative to the 3 Alaska regions, i.e., offshore North Slope, onshore North Slope, and South-Central Alaska),
- an order for the discovery sequence, and
- a schedule for the discovery sequence.

The new field discovery procedure relies on the U.S. Geological Survey (USGS) and Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) respective estimates of onshore and offshore technically recoverable oil resources as translated into the expected field size distribution of undiscovered fields. These onshore and offshore field size distributions are used to determine the field size and order of discovery in the AOGSS exploration and discovery process. Thus, the AOGSS oil field discovery process is consistent with the expected geology with respect to expected aggregate resource base and the relative frequency of field sizes.

AOGSS assumes that the largest fields in a region are found first, followed by successively smaller fields. This assumption is based on the following observations: 1) the largest volume fields typically encompass the greatest areal extent, thereby raising the probability of finding a large field relative to finding a smaller field, 2) seismic technology is sophisticated enough to be able to determine the location of the largest geologic structures that might possibly hold oil, 3) producers have a financial incentive to develop the largest fields first both because of their higher inherent rate of return and because the largest fields can pay for the development of expensive infrastructure that affords the opportunity to develop the smaller fields using that same infrastructure, and 4) historically, North Slope and Cook Inlet field development has generally progressed from largest field to smallest field.

Starting with the AEO2011, onshore and offshore North Slope new field wildcat drilling activity is a function of West Texas Intermediate crude oil prices from 1977 through 2008, expressed in 2008 dollars. The new field wildcat exploration function was statistically estimated based on West Texas Intermdiate crude oil prices from 1977 through 2008 and on exploration well drilling data obtained from the Alaska Oil and Gas Conservation Commission (AOGCC) data files for the same period.[3] The North Slope wildcat exploration drilling parameters were estimated using ordinary least squares methodology.

$$NAK\_NFW_t = (0.13856 * IT\_WOP_t) + 3.77 \tag{4-8}$$

where

t	=	year
NAK_NFW_t	=	North Slope Alaska field wildcat exploration wells
IT_WOP_t	=	World oil price in 2008 dollars

[3] A number of alternative functional formulations were tested (e.g., using Alaska crude oil prices, lagged oil prices, etc.), yet none of the alternative formations resulted in statistically more significant relationships.

The summary statistics for the statistical estimation are as follows:

```
Dependent variable: NSEXPLORE
Current sample:  1 to 32
Number of observations:  32

       Mean of dep. var. = 9.81250      LM het. test = .064580 [.799]
  Std. dev. of dep. var. = 4.41725     Durbin-Watson = 2.04186 [<.594]
Sum of squared residuals = 347.747  Jarque-Bera test = .319848 [.852]
   Variance of residuals = 11.5916   Ramsey's RESET2 = .637229E-04 [.994]
Std. error of regression = 3.40464   F (zero slopes) = 22.1824 [.000]
               R-squared = .425094    Schwarz B.I.C. = 87.0436
      Adjusted R-squared = .405930    Log likelihood = -83.5778

           Estimated    Standard
Variable  Coefficient     Error       t-statistic   P-value
C         3.77029       1.41706       2.66065       [.012]
WTIPRICE  .138559       .029419       4.70982       [.000]
```

Because very few offshore North Slope wells have been drilled since 1977, within AOGSS, the total number of exploration wells drilled on the North Slope are shared between the onshore and offshore regions, with the wells being predominantly drilled onshore in the early years of the projections with progressively more wells drilled offshore, such that after 20 years 50 percent of the exploration wells are drilled onshore and 50 percent are drilled offshore.

Based on the AOGCC data for 1977 through 2008, the drilling of South-Central Alaska new field wildcat exploration wells was statistically unrelated to oil prices. On average, 3 exploration wells per year were drilled in South-Central Alaska over the 1977 through 2008 timeframe, regardless of prevailing oil prices. This result probably stems from the fact that most of the South-Central Alaska drilling activity is focused on natural gas rather than oil, and that natural gas prices are determined by the Regulatory Commission of Alaska rather than being "market driven." Consequently, AOGSS specifies that 3 exploration wells are drilled each year.

The execution of the above procedure can be modified to reflect restrictions on the timing of discovery for particular fields. Restrictions may be warranted for enhancements such as delays necessary for technological development needed prior to the recovery of relatively small accumulations or heavy oil deposits. State and Federal lease sale schedules could also restrict the earliest possible date for beginning the development of certain fields. This refinement is implemented by declaring a start date for possible exploration. For example, AOGSS specifies that if Federal leasing in the Arctic National Wildlife Refuge were permitted in 2011, then the earliest possible date at which an ANWR field could begin oil production would be in 2021.[4] Another example is the wide-scale development of the West Sak field that is being delayed until a technology can be developed that will enable the heavy, viscous crude oil of that field to be economically extracted.

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[4]The earliest ANWR field is assumed to go into production 10 years after the first projection year; so the first field comes on line in 2020 for the *Annual Energy Outlook 2010* projections. See also *Analysis of Crude Oil Production in the Arctic National Wildlife Refugee*, EIA, SR/OIAF/2008-03, (May 2008).

Development Projects

Development projects are those projects in which a successful new field wildcat has been drilled. As with the new field discovery process, the DCF calculation plays an important role in the timing of development and exploration of these multi-year projects.

Each model year, the DCF is calculated for each potential development project. Initially, the model assumes a drilling schedule determined by the user or by some set of specified rules. However, if the DCF for a given project is negative, then development of this project is suspended in the year in which the negative DCF occurs. The DCF for each project is evaluated in subsequent years for a positive value. The model assumes that development would resume when a positive DCF value is calculated.

Production from developing projects follows the generalized production profile developed for and described in previous work conducted by DOE staff.[5] The specific assumptions used in this work are as follows:

- a 2- to 4-year build-up period from initial production to the peak production rate,
- the peak production rate is sustained for 3 to 8 years, and
- after peak production, the production rate declines by 12 to 15 percent per year.

The production algorithm build-up and peak-rate period are based on the expected size of the undiscovered field, with larger fields having longer build-up and peak-rate periods than the smaller fields. The field production decline rates are also determined by the field size.

The pace of development and the ultimate number of wells drilled for a particular field is based on the historical field-level profile adjusted for field size and other characteristics of the field (e.g. API gravity.)

After all exploratory and developmental wells have been drilled for a given project, development of the project is complete. For this version of the AOGSS, no constraint is placed on the number of exploratory or developmental wells that can be drilled for any project. All completed projects are added to the inventory of producing fields.

Development fields include fields that have already been discovered but have not begun production. These fields include, for example, a series of expansion fields in both the Prudhoe Bay area, the National Petroleum Reserve - Alaska (NPRA), and for various offshore fields. For these fields, the starting date of production and their production rates were not determined by the discovery process outlined above, but are based on public announcements by the company(s) developing those fields.

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[5] *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment*, EIA (May 2000) and *Alaska Oil and Gas - Energy Wealth of Vanishing Opportunity?*, DOE/ID/0570-H1 (January 1991).

Producing Fields

Oil production from fields producing as of the initial projection year (e.g., Prudhoe Bay, Kuparuk, Lisburne, Endicott, and Milne Point) are based on historical production patterns, remaining estimated recovery, and announced development plans. The production decline rates of these fields are periodically recalibrated based on recent field-specific production rates.

Natural gas production from the North Slope for sale to end-use markets depends on the construction of a pipeline to transport natural gas to lower 48 markets.[6] North Slope natural gas production is determined by the carrying capacity of a natural gas pipeline to the lower 48.[7] The Prudhoe Bay Field is the largest known deposit of North Slope gas (24.5 Tcf)[8] and currently all of the gas produced from this field is re-injected to maximize oil production. Total known North Slope gas resources equal 35.4 Tcf.[9] Furthermore, the undiscovered onshore central North Slope and NPRA technically recoverable natural gas resource base are respectively estimated to be 33.3 Tcf[10] and 52.8 Tcf.[11] Collectively, these North Slope natural gas reserves and resources equal 121.5 Tcf, which would satisfy the 1.64 Tcf per year gas requirements of an Alaska gas pipeline for almost 75 years, well after the end of the *Annual Energy Outlook* projections. Consequently, North Slope natural gas resources, both discovered and undiscovered, are more than ample to supply natural gas to an Alaska gas pipeline during the *Annual Energy Outlook* projection period.

[6]Initial natural gas production from the North Slope for Lower 48 markets is affected by a delay reflecting a reasonable period for construction. Details of how this decision is made in NEMS are included in the Natural Gas Transmission and Distribution Module documentation.

[7] The determination of whether an Alaska gas pipeline is economically feasible is calculated within the Natural Gas Transmission and Distribution Model.

[8] *Alaska Oil and Gas Report 2009*, Alaska Department of Natural Resources, Division of Oil and Gas, Table I.I, page 8.

[9] Ibid.

[10] U.S. Geological Survey, *Oil and Gas Assessment of Central North Slope, Alaska, 2005*, Fact Sheet 2005-3043, April 2005, page 2 table – mean estimate total.

[11] U.S. Geological Survey, *2010 Updated Assessment of Undiscovered Oil and Gas Resources of the National Petroleum Reserve in Alaska (NPRA)*, Fact Sheet 2010-3102, October 2010, Table 1 – mean estimate total, page 4.

Appendix 4.A. Alaskan Data Inventory

Variable Name		Description	Unit	Classification	Source
Code	Text				
ANGTSMAX	--	ANGTS maximum flow	BCF/D	Alaska	NPC
ANGTSPRC	--	Minimum economic price for ANGTS start up	1987$/MCF	Alaska	NPC
ANGTSRES	--	ANGTS reserves	BCF	Alaska	NPC
ANGTSYR	--	Earliest start year for ANGTS flow	Year	NA	NPC
DECLPRO	--	Alaska decline rates for currently producing fields	Fraction	Field	OPNGBA
DEV_AK	--	Alaska drilling schedule for developmental wells	Wells per year	3 Alaska regions; Fuel (oil, gas)	OPNGBA
DRILLAK	DRILL	Alaska drilling cost (not including new field wildcats)	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	OPNGBA
DRLNFWAK	--	Alaska drilling cost of a new field wildcat	1990$/well	3 Alaska regions; Fuel (oil, gas)	OPNGBA
DRYAK	DRY	Alaska dry hole cost	1990$/hole	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	OPNGBA
EQUIPAK	EQUIP	Alaska lease equipment cost	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	USGS
EXP_AK	--	Alaska drilling schedule for other exploratory wells	wells per year	3 Alaska regions	OPNGBA
FACILAK	--	Alaska facility cost (oil field)	1990$/bls	Field size class	USGS
FSZCOAK	--	Alaska oil field size distributions	MMB	3 Alaska regions	USGS
FSZNGAK	--	Alaska gas field size distributions	BCF	3 Alaska regions	USGS
HISTPRDCO	--	Alaska historical crude oil production	MB/D	Field	AOGCC
KAPFRCAK	EXKAP	Alaska drill costs that are tangible & must be depreciated	fraction	Alaska	U.S. Tax Code
MAXPRO	--	Alaska maximum crude oil production	MB/D	Field	Announced Plans
NAK_NFW	--	Number of new field wildcat wells drilling in Northern AK	wells per year	NA	OPNGBA
NFW_AK	--	Alaska drilling schedule for new field wildcats	wells	NA	OPNGBA
PRJAK	n	Alaska oil project life	Years	Fuel (oil, gas)	OPNGBA
PROYR	--	Start year for known fields in Alaska	Year	Field	Announced Plans

Variable Name					
Code	Text	Description	Unit	Classification	Source
RCPRDAK	m	Alaska recovery period of intangible & tangible drill cost	Years	Alaska	U.S. Tax Code
RECRES	--	Alaska crude oil resources for known fields	MMB	Field	OFE, *Alaska Oil and Gas - Energy Wealth or Vanishing Opportunity*
ROYRT	ROYRT	Alaska royalty rate	fraction	Alaska	USGS
SEVTXAK	PRODTAX	Alaska severance tax rates	fraction	Alaska	USGS
SRAK	SR	Alaska drilling success rates	fraction	Alaska	OPNGBA
STTXAK	STRT	Alaska state tax rate	fraction	Alaska	USGS
TECHAK	TECH	Alaska technology factors	fraction	Alaska	OPNGBA
TRANSAK	TRANS	Alaska transportation cost	1990$	3 Alaska regions; Fuel (oil, gas)	OPNGBA
XDCKAPAK	XDCKAP	Alaska intangible drill costs that must be depreciated	fraction	Alaska	U.S. Tax Code

Source: National Petroleum Council (NPC), EIA Office of Petroleum, Natural Gas, & Biofuels Analysis (OPNGBA), United States Geologic Survey (USGS), Alaska Oil and Gas Conservation Commission (AOGCC)

5. Oil Shale Supply Submodule

Oil shale rock contains a hydrocarbon known as kerogen,[12] which can be processed into a synthetic crude oil (syncrude) by heating the rock. During the 1970s and early 1980s, petroleum companies conducted extensive research, often with the assistance of public funding, into the mining of oil shale rock and the chemical conversion of the kerogen into syncrude. The technologies and processes developed during that period are well understood and well documented with extensive technical data on demonstration plant costs and operational parameters, which were published in the professional literature. The oil shale supply submodule in OGSM relies extensively on this published technical data for providing the cost and operating parameters employed to model the "typical" oil shale syncrude production facility.

In the 1970s and 1980s, two engineering approaches to creating the oil shale syncrude were envisioned. In one approach, which the majority of the oil companies pursued, the producer mines the oil shale rock in underground mines. A surface facility the retorts the rock to create bitumen, which is then further processed into syncrude. Occidental Petroleum Corp. pursued the other approach known as "modified in-situ," in which some of the oil shale rock is mined in underground mines, while the remaining underground rock is "rubblized" using explosives to create large caverns filled with oil shale rock. The rubblized oil shale rock is then set on fire to heat the kerogen and convert it into bitumen, with the bitumen being pumped to the surface for further processing into syncrude. The modified in-situ approach was not widely pursued because the conversion of kerogen into bitumen could not be controlled with any precision and because the leaching of underground bitumen and other petroleum compounds might contaminate underground aquifers.

When oil prices dropped below $15 per barrel in the mid-1990s, demonstrating an abundance of conventional oil supply, oil shale petroleum production became untenable and project sponsors canceled their oil shale research and commercialization programs. Consequently, no commercial-scale oil shale production facilities were ever built or operated. Thus, the technical and economic feasibility of oil shale petroleum production remains untested and unproven.

In 1997, Shell Oil Company started testing a completely in-situ oil shale process, in which the oil shale rock is directly heated underground using electrical resistance heater wells, while petroleum products[13] are produced from separate production wells. The fully in-situ process has significant environmental and cost benefits relative to the other two approaches. The environmental benefits are lower water usage, no waste rock disposal, and the absence of hydrocarbon leaching from surface waste piles. As an example of the potential environmental impact on surface retorting, an industry using 25 gallon per ton oil shale rock to produce 2 million barrels per day would generate about 1.2 billion tons of waste rock per year, which is about 11 percent more than the weight of all the coal mined in the United States in 2010. Other advantages of the in-situ process include: 1) access to deeper oil shale resources, 2) greater oil and gas generated per acre because the process uses multiple oil shale seams within the resource column rather than just a single seam, and 3) direct production of petroleum products rather than

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[12] Kerogen is a solid organic compound, which is also found in coal.

[13] Approximately, 30 percent naphtha, 30 percent jet fuel, 30 percent diesel, and 10 percent residual fuel oil.

a synthetic crude oil that requires more refinery processing. Lower production costs are expected for the in-situ approach because massive volumes of rock would not be moved, and because the drilling of heater wells, production wells, and freeze-wall wells can be done in a modular fashion, which allows for a streamlined manufacturing-like process. Personnel safety would be greater and accident liability lower. Moreover, the in-situ process reduces the capital risk, because it involves building self-contained modular production units that can be multiplied to reach a desired total production level. Although the technical and economic feasibility of the in-situ approach has not been commercially demonstrated, there is already a substantial body of evidence from field tests conducted by Shell Oil Co. that the in-situ process is technologically feasible.[14] The current Shell field research program is expected to conclude around the 2014 through 2017 timeframe with the construction of a small scale demonstration plant expected to begin shortly thereafter. The Oil Shale Supply Submodule (OSSS) assumes that the first commercial size oil shale plant cannot be built prior to 2017.

Given the inherent cost and environmental benefits of the in-situ approach, a number of other companies, such as Chevron and ExxonMobil are testing alternative in-situ oil shale techniques. Although small-scale mining and surface retorting of oil shale is currently being developed, by companies such as Red Leaf Resources, the large scale production of oil shale will most likely use the in-situ process. However, because in-situ oil shale projects have never been built, and because companies developing the in-situ process have not publicly released detailed technical parameters and cost estimates, the cost and operational parameters of such in-situ facilities is unknown. Consequently, the Oil Shale Supply Submodule (OSSS) relies on the project parameters and costs associated with the underground mining and surface retorting approach that were designed during the 1970s and 1980s. In this context, the underground mining and surface retorting facility parameters and costs are meant to be a surrogate for the in-situ oil shale facility that is more likely to be built. Although the in-situ process is expected to result in a lower cost oil shale product, this lower cost is somewhat mitigated by the fact that the underground mining and surface retorting processes developed in the 1970s and 1980s did not envision the strict environmental regulations that prevail today, and therefore embody an environmental compliance cost structure that is lower than what would be incurred today by a large-scale underground mining and surface retorting facility. Also, the high expected cost structure of the underground mining/surface retorting facility constrains the initiation of oil shale project production, which should be viewed as a more conservative approach to simulating the market penetration of in-situ oil projects. On the other hand, OSSS oil shale facility costs are reduced by 1 percent per year to reflect technological progress, especially with respect to the improvement of an in-situ oil shale process. Finally, public opposition to building any type of oil shale facility is likely to be great, regardless of the fact that the in-situ process is expected to be more environmentally benign than the predecessor technologies; the cost of building an in-situ oil shale facility is therefore likely to be considerably greater than would be determined strictly by the engineering parameters of such a facility.[15]

The Oil Shale Supply Submodule (OSSS) only represents economic decision making. In the absence of any existing commercial oil shale projects, it was impossible to determine the

[14] *See* "Shell's In-situ Conversion Process," a presentation by Harold Vinegar at the Colorado Energy Research Institute's 26th Oil Shale Symposium held on October 16 – 18, 2006 in Boulder, Colorado.

[15] Project delays due to public opposition can significantly increase project costs and reduce project rates of return.

potential environmental constraints and costs of producing oil on a large scale. Given the considerable technical and economic uncertainty of an oil shale industry based on an in-situ technology, and the infeasibility of the large-scale implementation of an underground mining/surface retorting technology, the oil shale syncrude production projected by the OSSS should be considered highly uncertain.

Given this uncertainty, the construction of commercial oil shale projects is constrained by a linear market penetration algorithm that restricts the oil production rate, which, at best, can reach a maximum of 2 million barrels per day by the end of a 40-year period after commercial oil shale facilities are deemed to be technologically feasible (starting in 2017). Whether domestic oil shale production actually reaches 2 million barrels per day at the end of the 40-year period depends on the relative profitability of oil shale facilities. If oil prices are too low to recover the weighted average cost of capital, no new facilities are built. However, if oil prices are sufficiently high to recover the cost of capital, then the rate of market penetration rises in direct proportion to facility profitability. So as oil prices rise and oil shale facility profitability increases, the model assumes that oil shale facilities are built in greater numbers, as dictated by the market penetration algorithm.

The 2 million barrel per day production limit is based on an assessment of what is feasible given both the oil shale resource base and potential environmental constraints.[16] The 40-year minimum market penetration timeframe is based on the observation that "…an oil shale production level of 1 million barrels per day is probably more than 20 years in the future…"[17] with a linear ramp-up to 2 million barrels per day equating to a 40-year minimum.

The actual rate of market penetration in the OSSS largely depends on projected oil prices, with low prices resulting in low rates of market penetration, and with the maximum penetration rate only occurring under high oil prices that result in high facility profitability. The development history of the Canadian oil sands industry is an analogous situation. The first commercial Canadian oil sands facility began operations in 1967; the second project started operation in 1978; and the third project initiated production in 2003.[18] So even though the Canadian oil sands resource base is vast, it took over 30 years before a significant number of new projects were announced. This slow penetration rate, however, was largely caused by both the low world oil prices that persisted from the mid-1980s through the 1990s and the lower cost of developing conventional crude oil supply.[19] The rise in oil prices that began in 2003 caused 17 new oil sands projects to be announced by year-end 2007.[20] Oil prices subsequently peaked in July 2008,

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[16] *See* U.S. Department of Energy, "Strategic Significance of America's Oil Shale Resource," March 2004, Volume I, page 23 – which speaks of an "aggressive goal" of 2 million barrels per day by 2020; and Volume II, page 7 – which concludes that the water resources in the Upper Colorado River Basin are "more than enough to support a 2 million barrel/day oil shale industry…"

[17] Source: RAND Corporation, "Oil Shale Development in the United States – Prospects and Policy Issues," MG-414, 2005, Summary page xi.

[18] The owner/operator for each of the 3 initial oil sands projects were respectively Suncor, Syncrude, and Shell Canada.

[19] The first Canadian commercial oil sands facility started operations in 1967. It took 30 years later until the mid to late 1990s for a building boom of Canadian oil sands facilities to materialize. Source: Suncor Energy, Inc. internet website at www.suncor.com, under "our business," under "oil sands."

[20] Source: Alberta Employment, Immigration, and Industry, "Alberta Oil Sands Industry Update," December 2007, Table 1, pages 17 – 21.

and declined significantly, such that a number of these new projects were put on hold at that time.

Extensive oil shale resources exist in the United States both in eastern Appalachian black shales and western Green River Formation shales. Almost all of the domestic high-grade oil shale deposits with 25 gallons or more of petroleum per ton of rock are located in the Green River Formation, which is situated in Northwest Colorado (Piceance Basin), Northeast Utah (Uinta Basin), and Southwest Wyoming. It has been estimated that over 400 billion barrels of syncrude potential exists in Green River Formation deposits that would yield at least 30 gallons of syncrude per ton of rock in zones at least 100 feet thick.[21] Consequently, the Oil Shale Supply Submodule assumes that future oil shale syncrude production occurs exclusively in the Rocky Mountains within the 2035 time frame of the projections. Moreover, the immense size of the western oil shale resource base precluded the need for the submodule to explicitly track oil shale resource depletion through 2035.

For each projection year, the oil shale submodule calculates the net present cash flow of operating a commercial oil shale syncrude production facility, based on that future year's projected crude oil price. If the calculated discounted net present value of the cash flow exceeds zero, the submodule assumes that an oil shale syncrude facility would begin construction, so long as the construction of that facility is not precluded by the construction constraints specified by the market penetration algorithm. So the submodule contains two major decision points for determining whether an oil shale syncrude production facility is built in any particular year: first, whether the discounted net present value of a facility's cash flow exceeds zero; second, by a determination of the number of oil shale projects that can be initiated in that year, based on the maximum total oil shale production level that is permitted by the market penetration algorithm.

In any one year, many oil shale projects can be initiated, raising the projected production rates in multiples of the rate for the standard oil shale facility, which is assumed to be 50,000 barrels per day, per project.

Oil Shale Facility Cost and Operating Parameter Assumptions

The oil shale supply submodule is based on underground mining and surface retorting technology and costs. During the late 1970s and early 1980s, when petroleum companies were building oil shale demonstration plants, almost all demonstration facilities employed this technology.[22] The facility parameter values and cost estimates in the OSSS are based on information reported for the Paraho Oil Shale Project, and which are inflated to constant 2004 dollars.[23] Oil shale rock mining costs are based on Western United States underground coal mining costs, which would be representative of the cost of mining oil shale rock, [24] because coal

[21] Source: Culbertson, W. J. and Pitman, J. K. "Oil Shale" in *United States Mineral Resources*, USGS Professional Paper 820, Probst and Pratt, eds. P 497-503, 1973.

[22] Out of the many demonstration projects in the 1970s only Occidental Petroleum tested a modified in-situ approach which used caved-in mining areas to perform underground retorting of the kerogen.

[23] Source: Noyes Data Corporation, *Oil Shale Technical Data Handbook*, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97.

[24] Based on the coal mining cost per ton data provided in coal company 2004 annual reports, particularly those of

mining techniques and technology would be employed to mine oil shale rock. However, the OSSS assumes that oil shale production costs fall at a rate of 1 percent per year, starting in 2005, to reflect the role of technological progress in reducing production costs. This cost reduction assumption results in oil shale production costs being 26 percent lower in 2035 relative to the initial 2004 cost structure.

Although the Paraho cost structure might seem unrealistic, given that the application of the in-situ process is more likely than the application of the underground mining/surface retorting process, the Paraho cost structure is well documented, while there is no detailed public information regarding the expected cost of the in-situ process. Even though the in-situ process might be cheaper per barrel of output than the Paraho process, this should be weighted against the following facts 1) oil and gas drilling costs have increased dramatically since 2005, somewhat narrowing that cost difference, and 2) the Paraho costs were determined at a time when environmental requirements were considerably less stringent. Consequently, the environmental costs that an energy production project would incur today are considerably more than what was envisioned in the late-1970s and early-1980s. It should also be noted that the Paraho process produces about the same volumes of oil and natural gas as the in-situ process does, and requires about the same electricity consumption as the in-situ process. Finally, to the degree that the Paraho process costs reported here are greater than the in-situ costs, the use of the Paraho cost structure provides a more conservative facility cost assessment, which is warranted for a completely new technology.

Another implicit assumption in the OSSS is that the natural gas produced by the facility is sold to other parties, transported offsite, and priced at prevailing regional wellhead natural gas prices. Similarly, the electricity consumed on site is purchased from the local power grid at prevailing industrial prices. Both the natural gas produced and the electricity consumed are valued in the Net Present Value calculations at their respective regional prices, which are determined elsewhere in the NEMS. Although the oil shale facility owner has the option to use the natural gas produced on-site to generate electricity for on-site consumption, building a separate on-site/offsite power generation decision process within OSSS would unduly complicate the OSSS logic structure and would not necessarily provide a more accurate portrayal of what might actually occur in the future.[25] Moreover, this treatment of natural gas and electricity prices automatically takes into consideration any embedded carbon dioxide emission costs associated with a particular NEMS scenario, because a carbon emissions allowance cost is embedded in the regional natural gas and electricity prices and costs.

OSSS Oil Shale Facility Configuration and Costs

The OSSS facility parameters and costs are based on those reported for the Paraho Oil Shale

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Arch Coal, Inc, CONSOL Energy Inc, and Massey Energy Company. Reported underground mining costs per ton range for $14.50 per ton to $27.50 per ton. The high cost figures largely reflect higher union wage rates, than the low cost figures reflect non-union wage rates. Because most of the Western underground mines are currently non-union, the cost used in OSSS was pegged to the lower end of the cost range. For example, the $14.50 per ton cost represents Arch Coal's average western underground mining cost.

[25] The Colorado/Utah/Wyoming region has relatively low electric power generation costs due to 1) the low cost of mining Powder River Basin subbituminous coal, and 2) the low cost of existing electricity generation equipment, which is inherently lower than new generation equipment due cost inflation and facility depreciation.

project. Because the Paraho Oil Shale Project costs were reported in 1976 dollars, the OSSS costs were inflated to constant 2004 dollar values. Similarly, the OSSS converts NEMS oil prices, natural gas prices, electricity costs, and carbon dioxide costs into constant 2004 dollars, so that all facility net present value calculations are done in constant 2004 dollars. Based on the Paraho Oil Shale Project configuration, OSSS oil shale facility parameters and costs are listed in Table 5-1, along the OSSS variable names. For the *Annual Energy Outlook 2009* and subsequent *Outlooks*, oil shale facility construction costs were increased by 50 percent to represent the world-wide increase in steel and other metal prices since the OSSS was initially designed. For the *Annual Energy Outlook 2011*, the oil shale facility plant size was reduced from 100,000 barrels per day to 50,000 barrels per day, based on discussions with industry representatives who believe that the smaller configuration was more likely for in-situ projects because this size captures most of the economies of scale, while also reducing project risk.

Table 5-1. OSSS Oil Shale Facility Configuration and Cost Parameters

Facility Parameters	OSSS Variable Name	Parameter Value
Facility project size	OS_PROJ_SIZE	50,000 barrels per day
Oil shale syncrude per ton of rock	OS_GAL_TON	30 gallons
Plant conversion efficiency	OS_CONV_EFF	90 percent
Average facility capacity factor	OS_CAP_FACTOR	90 percent per year
Facility lifetime	OS_PRJ_LIFE	20 years
Facility construction time	OS_PRJ_CONST	3 year
Surface facility capital costs	OS_PLANT_INVEST	$2.4 billion (2004 dollars)
Surface facility operating costs	OS_PLANT_OPER_CST	$200 million per year (2004 dollars)
Underground mining costs	OS_MINE_CST_TON	$17.50 per ton (2004 dollars)
Royalty rate	OS_ROYALTY_RATE	12.5 percent of syncrude value
Carbon Dioxide Emissions Rate	OS_CO2EMISS	150 metric tons per 50,000 bbl/day of production[26]

The construction lead time for oil shale facilities is assumed to be 3 years, which is less than the 5-year construction time estimates developed for the Paraho Project. The shorter construction period is based on the fact that the drilling of shallow in-situ heating and production wells can be accomplished much more quickly than the erection of a surface retorting facility. Because it is not clear when during the year a new plant will begin operation and achieve full productive capacity, OSSS assumes that production in the first full year will be at half its rated output and that full capacity will be achieved in the second year of operation.

To mimic the fact that an industry's costs decline over time due to technological progress, better management techniques, and so on, the OSSS initializes the oil shale facility costs in the year 2005 at the values shown above (i.e., surface facility construction and operating costs, and underground mining costs). After 2005, these costs are reduced by 1 percent per year through 2035, which is consistent with the rate of technological progress witnessed in the petroleum industry over the last few decades.

[26] Based on the average of the Fischer Assays determined for four oil shale rock samples of varying kerogen content. Op. cit. Noyes Data Corporation, Table 3.8, page 20.

OSSS Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters

Based on the Paraho Oil Shale Project parameters, Table 5-2 provides the level of annual gas production and annual electricity consumption for a 50,000 barrel per day, operating at 100 percent capacity utilization for a full calendar year.[27]

Table 5-2. OSSS Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters and Their Prices and Costs

Facility Parameters	OSSS Variable Name	Parameter Value
Natural gas production	OS_GAS_PROD	16.1 billion cubic feet per year
Wellhead gas sales price	OS_GAS_PRICE	Dollars per Mcf (2004 dollars)
Electricity consumption	OS_ELEC_CONSUMP	0.83 billion kilowatt-hours per year
Electricity consumption price	OS_ELEC_PRICE	Dollars per kilowatt-hour (2004 dollars)

Project Yearly Cash Flow Calculations

The OSSS first calculates the annual revenues minus expenditures, including income taxes and depreciation expenses, which is then discounted to a net present value. In those future years in which the net present value exceeds zero, a new oil shale facility can begin construction, subject to the timing constraints outlined below.

The discounted cash flow algorithm is calculated for a 23 year period, composed of 3 years for construction and 20 years for a plant's operating life. During the first 3 years of the 23-year period, only plant construction costs are considered with the facility investment cost being evenly apportioned across the 3 years. In the fourth year, the plant goes into partial operation, and produces 50 percent of the rated output. In the fifth year, revenues and operating expenses are assumed to ramp up to the full-production values, based on a 90 percent capacity factor that allows for potential production outages. During years 4 through 23, total revenues equal oil production revenues plus natural gas production revenues.[28]

Discounted cash flow oil and natural gas revenues are calculated based on prevailing oil and natural gas prices projected for that future year. In other words, the OSSS assumes that the economic analysis undertaken by potential project sponsors is solely based on the prevailing price of oil and natural gas at that time in the future and is not based either on historical price trends or future expected prices. Similarly, industrial electricity consumption costs are also based on the prevailing price of electricity for industrial consumers in that region at that future time.

As noted earlier, during a plant's first year of operation (year 4), both revenues and costs are half the values calculated for year 5 through year 23.

[27] Op. cit. Noyes Data Corporation, pages 89-97.

[28] Natural gas production revenues result from the fact that significant volumes of natural gas are produced when the kerogen is retorted in the surface facilities. See prior table regarding the volume of natural gas produced for a 50,000 barrel per day oil shale syncrude facility.

Oil revenues are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned}\mathrm{OIL\_REVENUE}_t = {} & \mathrm{OIT\_WOP}_t * (1.083/0.732) * \mathrm{OS\_PRJ\_SIZE} \\ & * \mathrm{OS\_CAP\_FACTOR} * 365\end{aligned} \tag{5-8}$$

where

$\mathrm{OIT\_WOP}_t$	=	World oil price at time t in 1987 dollars
(1.083 / 0.732)	=	GDP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_PROJ_PRJ_SIZE	=	Facility project size in barrels per day
OS_CAP_FACTOR	=	Facility capacity factor
365	=	Days per year.

Natural gas revenues are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned}\mathrm{GAS\_REVENUE}_t = {} & \mathrm{OS\_GAS\_PROD} * \mathrm{OGPRCL48}_t * 1.083/0.732) \\ & *\mathrm{OS\_CAP\_FACTOR},\end{aligned} \tag{5-9}$$

where

OS_GAS_PROD	=	Annual natural gas production for 50,000 barrel per day facility
$\mathrm{OGPRCL48}_t$	=	Natural gas price in Rocky Mtn. at time t in 1987 dollars
(1.083 / 0.732)	=	GDP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_CAP_FACTOR	=	Facility capacity factor.

Electricity consumption costs are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned}\mathrm{ELECT\_COST}_t = {} & \mathrm{OS\_ELEC\_CONSUMP} * \mathrm{PELIN}_t * (1.083/.732) * 0.003412 \\ & * \mathrm{OS\_CAP\_FACTOR}\end{aligned} \tag{5-10}$$

where

OS_ELEC_CONSUMP	=	Annual electricity consumption for 50,000 barrel per day facility
PELIN_t	=	Electricity price Colorado/Utah/Wyoming at time t
(1.083 / .732)	=	GNP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_CAP_FACTOR	=	Facility capacity factor.

The carbon dioxide emission tax rate per metric ton is calculated as follows:

$$\mathrm{OS\_EMETAX}_t = \mathrm{EMETAX}_t(1) * 1000.0 * (12.0/44.0) * (1.083/.732) \tag{5-11}$$

where,

$EMETAX_t(1)$	=	Carbon emissions allowance price/tax per kilogram at time t
1,000	=	Convert kilograms to metric tones
(12.0 / 44.0)	=	Atomic weight of carbon divided by atomic weight of carbon dioxide
(1.083 / .732)	=	GNP chain-type price deflators to convert 1987 dollars into 2004 dollars.

Annual carbon dioxide emission costs per plant are calculated as follows:

$$CO2\_COST_t = OS\_EMETAX_t * OS\_CO2EMISS * 365 * OS\_CAP\_FACTOR \tag{5-12}$$

where

OS_EMETAX_t	=	Carbon emissions allowance price/tax per metric tonne at time t in 2004 dollars
OS_CO2EMISS	=	Carbon dioxide emissions in metric tonnes per day
365	=	Days per year
OS_CAP_FACTOR	=	Facility capacity factor

In any given year, pre-tax project cash flow is:

$$PRETAX\_CASH\_FLOW_t = TOT\_REVENUE_t - TOTAL\_COST_t \tag{5-13}$$

where

$TOT\_REVENUE_t$	=	Total project revenues at time t
TOT_COST_t	=	Total project costs at time t.

Total project revenues are calculated as follows:

$$TOT\_REVENUE_t = OIL\_REVENUE_t + GAS\_REVENUE_t \tag{5-14}$$

Total project costs are calculated as follows:

$$\begin{aligned} TOT\_COST_t = & OS\_PLANT\_OPER\_CST + ROYALTY_t + PRJ\_MINE\_CST \\ & + ELEC\_COST_t + CO2\_COST_t + INVEST_t \end{aligned} \tag{5-15}$$

where

$$OS\_PLANT\_OPER\_CST = \text{Annual plant operating costs per year}$$
$$ROYALTY_t = \text{Annual royalty costs at time t}$$
$$PRJ\_MINE\_COST = \text{Annual plant mining costs}$$
$$ELEC\_COST_t = \text{Annual electricity costs at time t}$$
$$CO2\_COST_t = \text{Annual carbon dioxide emissions costs at time t}$$
$$INVEST_t = \text{Annual surface facility investment costs.}$$

While the plant is under construction (years 1 through 3) only INVEST has a positive value, while the other four cost elements equal zero. When the plant goes into operation (years 4 through 23), the capital costs (INVEST) are zero, while the other five operating costs take on positive values. The annual investment cost for the three years of construction is calculated as follows, under the assumption that the construction costs are evenly spread over the 3-year construction period:

$$INVEST = OS\_PLANT\_INVEST / OS\_PRJ\_CONST \tag{5-16}$$

where the variables are defined as in Table 5-1. Because the plant output is composed of both oil and natural gas, the annual royalty cost (ROYALTY) is calculated by applying the royalty rate to total revenues, as follows:

$$ROYALTY_t = OS\_ROYALTY\_RATE * TOT\_REVENUE_t \tag{5-17}$$

Annual project mining costs are calculated as the mining cost per barrel of syncrude multiplied by the number of barrels produced, as follows:

$$\begin{aligned} PRJ\_MINE\_COST = OS\_MINE\_CST\_TON * \frac{42}{OS\_GALLON\_TON * OS\_CONV\_EFF} \\ * OS\_PROJ\_SIZE * OS\_CAP\_FACTOR * 365 \end{aligned} \tag{5-18}$$

where

$$42 = \text{gallons per barrel}$$
$$365 = \text{days per year.}$$

After the plant goes into operation and after a pre-tax cash flow is calculated, then a post-tax cash flow has to be calculated based on income taxes and depreciation tax credits. When the prevailing world oil price is sufficiently high and the pre-tax cash flow is positive, then the following post-tax cash flow is calculated as

$$\begin{aligned} CASH\_FLOW_t = \left(PRETAX\_CASH\_FLOW_t * (1 - OS\_CORP\_TAX\_RATE)\right) + \\ (OS\_CORP\_TAX\_RATE * OS\_PLANT\_INVEST / OS\_PRJ\_LIFE) \end{aligned} \tag{5-19}$$

The above depreciation tax credit calculation assumes straight-line depreciation over the operating life of the investment (OS_PRJ_LIFE).

Discount Rate Financial Parameters

The discounted cash flow algorithm uses the following financial parameters to determine the discount rate used in calculating the net present value of the discounted cash flow.

Table 5-3. Discount Rate Financial Parameters

Financial Parameters	OSSS Variable Name	Parameter Value
Corporate income tax rate	OS_CORP_TAX_RATE	38 percent
Equity share of total facility capital	OS_EQUITY_SHARE	60 percent
Facility equity beta	OS_EQUITY_VOL	1.8
Expected market risk premium	OS_EQUITY_PREMIUM	6.5 percent
Facility debt risk premium	OS_DEBT_PREMIUM	0.5 percent

The corporate equity beta (OS_EQUITY_VOL) is the project risk beta, not a firm's volatility of stock returns relative to the stock market's volatility. Because of the technology and construction uncertainties associated with oil shale plants, the project's equity holder's risk is expected to be somewhat greater than the average industry firm beta. The median beta for oil and gas field exploration service firms is about 1.65. Because a project's equity holders' investment risk level is higher, the facility equity beta assumed for oil shale projects is 1.8.

The expected market risk premium (OS_EQUITY_PREMIUM), which is 6.5 percent, is the expected return on market (S&P 500) over the rate of 10-year Treasury note (risk-free rate). A Monte Carlo simulation methodology was used to estimate the expected market return.

Oil shale project bond ratings are expected to be in the Ba-rating range. Since the NEMS macroeconomic module endogenously determines the industrial Baa bond rates for the forecasting period, the cost of debt rates are different in each year. The debt premium (OS_DEBT_PREMIUM) adjusts the bond rating for the project from the Baa to the Ba range, which is assumed to be constant at the average historical differential over the forecasting period.

Discount Rate Calculation

A seminal parameter used in the calculation of the net present value of the cash flow is the discount rate. The calculation of the discount rate used in the oil shale submodule is consistent with the way the discount rate is calculated through the National Energy Modeling System. The discount rate equals the post-tax weighted average cost of capital, which is calculated in the OSSS as follows:

$$
\begin{aligned}
OS\_DISCOUNT\_RATE_t = (((1-OS\_EQUITY\_SHARE)*(MC\_RMCORPBAA_t/100+ \\
OS\_DEBT\_PREMIUM))*(1-OS\_CORP\_TAX\_RATE)+ \\
(OS\_EQUITY\_SHARE*((OS\_EQUITY\_PREMIUM* \\
OS\_EQUITY\_VOL)+MC\_RMGFCM\_10NS_t/100))
\end{aligned}
\tag{5-20}
$$

where

OS_EQUITY_SHARE	=	Equity share of total facility capital
$MC\_RMCORPBAA_t/100$	=	BAA corporate bond rate
OS_DEBT_PREMIUM	=	Facility debt risk premium
OS_CORP_TAX_RATE	=	Corporate income tax rate
OS_EQUITY_PREMIUM	=	Expected market risk premium
OS_EQUITY_VOL	=	Facility equity volatility beta
$MC\_RMGFCM\_10NS_t/100$	=	10-year Treasury note rate.

In calculating the facility's cost of equity, the equity risk premium (which is a product of the expected market premium and the facility equity beta, is added to a "risk-free" rate of return, which is considered to be the 10-year Treasury note rate.

The nominal discount rate is translated into a constant, real discount rate using the following formula:

$$
OS\_DISCOUNT\_RATE_t = ((1.0+OS\_DISCOUNT\_RATE_t)/(1.0+INFL_t))-1.0 \tag{5-21}
$$

where

$INFL_t$ = Inflation rate at time t.

Net Present Value Discounted Cash Flow Calculation

So far a potential project's yearly cash flows have been calculated along with the appropriate discount rate. Using these calculated quantities, the net present value of the yearly cash flow values is calculated as follows:

$$
NET\_CASH\_FLOW_{t-1} = \sum_{t=1}^{OS\_PRJ\_LIFE+OS\_PRJ\_CONST} \left[CASH\_FLOW_t * \left[\frac{1}{1+OS\_DISCOUNT\_RATE_t} \right]^t \right] \tag{5-22}
$$

If the net present value of the projected cash flows exceeds zero, then the potential oil shale facility is considered to be economic and begins construction, so long as this facility construction does not violate the construction timing constraints detailed below.

Oil Shale Facility Market Penetration Algorithm

As noted in the introduction, there is no empirical basis for determining how rapidly new oil shale facilities would be built, once the OSSS determines that surface-retorting oil shale facilities are economically viable, because no full-scale commercial facilities have ever been constructed. However, there are three primary constraints to oil shale facility construction. First, the construction of an oil shale facility cannot be undertaken until the in-situ technology has been sufficiently developed and tested to be deemed ready for its application to commercial size projects (i.e., 50,000 barrels per day). Second, oil shale facility construction is constrained by the maximum oil shale production limit. Third, oil shale production volumes cannot reach the maximum oil shale production limit any earlier than 40 years after the in-situ technology has been deemed to be feasible and available for commercial size facilities. Table 5-4 summarizes the primary market penetration parameters in the OSSS.

Table 5-4. Market Penetration Parameters

Market Penetration Parameters	OSSS Variable Name	Parameter Value
Earliest Facility Construction Start Date	OS_START_YR	2017
Maximum Oil Shale Production	OS_MAX_PROD	2 million barrels per year
Minimum Years to Reach Full Market Penetration	OS_PENETRATE_YR	40

Shell's in-situ oil shale RD&D program is considered to be the most advanced, having begun in 1997. Shell is most likely to be the first party to build and operate a commercial scale oil shale production facility. Based on conversations between Shell personnel and EIA personnel, Shell is likely to conclude its field experiments, which test the various components of a commercial facility sometime during the 2014 through 2017 timeframe. Consequently, the earliest likely initiation of a full-scale commercial plant would be 2017.[29]

As discussed earlier, a 2 million barrel per day oil shale production level at the end of 40-year market penetration period is considered to be reasonable and feasible based on the size of the resource base and the volume and availability of water needed to develop those resources. The actual rate of market penetration in the OSSS, however, is ultimately determined by the projected profitability of oil shale projects. At a minimum, oil and natural gas prices must be sufficiently high to produce a facility revenue stream (i.e., discounted cash flow) that covers all capital and operating costs, including the weighted average cost of capital. When the discounted cash flow exceeds zero (0), then the market penetration algorithm allows oil shale facility construction to commence.

[29] Op. cit. EIA/OIAF/OGD memorandum entitled, "Oil Shale Project Size and Production Ramp-Up," and based on public information and private conversations subsequent to the development of that memorandum.

When project discounted cash flow is greater than zero, the relative project profitability is calculated as follows:

$$OS\_PROFIT_t = DCF_t \ / \ OS\_PLANT\_INVEST \tag{5-23}$$

where

DCF_t = Project discounted cash flow at time t
OS_PLANT_INVEST = Project capital investment

OS_PROFIT is an index of an oil project's expected profitability. The expectation is that, as OS_PROFIT increases, the relative financial attractiveness of producing oil shale also increases.

The level of oil shale facility construction that is permitted in any year depends on the maximum oil shale production that is permitted by the following market penetration algorithm:

$$\begin{aligned} MAX\_PROD_t = {} & OS\_MAX\_PROD * (OS\_PROFIT_t \ / \ (1 + OS\_PROFIT_t)) \\ & * ((T - (OS\_START\_YR - 1989)) \ / \ OS\_PENETRATE\_YR\ ) \end{aligned} \tag{5-24}$$

where,

OS_MAX_PROD	=	Maximum oil shale production limit
OS_PROFIT_t	=	Relative oil shale project profitability at time t
T	=	Time t
OS_START_YR	=	First year that an oil shale facility can be built
OS_PENTRATE_YR	=	Minimum number of years during which the maximum oil shale production can be achieved.

The OS_PROFIT portion of the market penetration algorithm (5-24) rapidly increases market penetration as the DCF numerator of OS_PROFIT increases. However, as OS_PROFIT continues to increase, the rate of increase in market penetration slows as (OS_PROFIT / (1 + OS_PROFIT) asymptotically approaches one (1.0). As this term approaches 1.0, the algorithm's ability to build more oil shale plants is ultimately constrained by OS_MAX_PROD term, regardless of how financially attractive the construction of new oil shale facilities might be. This formulation also prevents MAX_PROD from exceeding OS_MAX_PROD.

The second portion of the market penetration algorithm specifies that market penetration increases linearly over the number of years specified by OS_PENETRATE_YR. As noted earlier OS_PENETRATE_YR specifies the minimum number of years over which the oil shale industry can achieve maximum penetration. The maximum number of years required to achieve full penetration is dictated by the speed at which the OS_PROFIT portion of the equation approaches one (1.0). If OS_PROFIT remains low, then it is possible that MAX_PROD never comes close to reaching the OS_MAX_PROD value.

The number of new oil shale facilities that start construction in any particular year is specified by the following equation:

(5-25)

$$OS\_PLANTS\_NEW_t = INT((MAX\_PROD_t - (OS\_PLANTS_t * OS\_PRJ\_SIZE * OS\_CAP\_FACTOR)) / (OS\_PRJ\_SIZE * OS\_CAP\_FACTOR))$$

where

MAX_PROD_t	=	Maximum oil shale production at time t
OS_PLANT_t	=	Number of existing oil shale plants at time t
OS_PRJ_SIZE	=	Standard oil shale plant size in barrels per day
OS_CAP_FACTOR	=	Annual capacity factor of an oil shale plant in percent per year.

The first portion of the above formula specifies the incremental production capacity that can be built in any year, based on the number of plants already in existence. The latter portion of the equation determines the integer number of new plants that can be initiated in that year, based on the expected annual production rate of an oil shale plant.

Because oil shale production is highly uncertain, not only from a technological and economic perspective, but also from an environmental perspective, an upper limit to oil shale production is assumed within the OSSS. The upper limit on oil shale production is 2 million barrels per day, which is equivalent to 44 facilities of 50,000 barrels per day operating at a 90 percent capacity factor. So the algorithm allows enough plants to be built to fully reach the oil shale production limit, based on the expected plant capacity factor. As noted earlier, the oil shale market penetration algorithm is also limited by the earliest commercial plant construction date, which is assumed to be no earlier than 2017.

While the OSSS costs and performance profiles are based on technologies evaluated in the 1970’s and early 1980’s, the complete absence of any current commercial-scale oil shale production makes its future economic development highly uncertain. If the technological, environmental, and economic hurdles are as high or higher than those experienced during the 1970’s, then the prospects for oil shale development would remain weak throughout the projections. However, technological progress can alter the economic and environmental landscape in unanticipated ways. For example, if an in-situ oil shale process were to be demonstrated to be both technically feasible and commercially profitable, then the prospects for an oil shale industry would improve significantly, and add vast economically recoverable oil resources in the United States and possibly elsewhere in the world.

Appendix A. Discounted Cash Flow Algorithm

Introduction

The basic DCF methodology used in the Oil and Gas Supply Module (OGSM) is applied for a broad range of oil or natural gas projects, including single well projects or multiple well projects within a field. It is designed to capture the effects of multi-year capital investments (e.g., offshore platforms). The expected discounted cash flow value associated with exploration and/or development of a project with oil or gas as the primary fuel in a given region evaluated in year T may be presented in a stylized form (Equation A-1).

$$\begin{aligned} DCF_T = (&PVTREV - PVROY - PVPRODTAX - PVDRILLCOST - PVEQUIP \\ &- PVKAP - PVOPCOST - PVABANDON - PVSIT - PVFIT)_T \end{aligned} \tag{A-1}$$

where

T	=	year of evaluation
PVTREV	=	present value of expected total revenues
PVROY	=	present value of expected royalty payments
PVPRODTAX	=	present value of expected production taxes (ad valorem and severance taxes)
PVDRILLCOST	=	present value of expected exploratory and developmental drilling expenditures
PVEQUIP	=	present value of expected lease equipment costs
PVKAP	=	present value of other expected capital costs (i.e., gravel pads and offshore platforms)
PVOPCOST	=	present value of expected operating costs
PVABANDON	=	present value of expected abandonment costs
PVSIT	=	present value of expected state corporate income taxes
PVFIT	=	present value of expected federal corporate income taxes.

Costs are assumed constant over the investment life but vary across both region and primary fuel type. This assumption can be changed readily if required by the user. Relevant tax provisions also are assumed unchanged over the life of the investment. Operating losses incurred in the initial investment period are carried forward and used against revenues generated by the project in later years.

The following sections describe each component of the DCF calculation. Each variable of Equation A.1 is discussed starting with the expected revenue and royalty payments, followed by the expected costs, and lastly the expected tax payments.

Present Value of Expected Revenues, Royalty Payments, and Production Taxes

Revenues from an oil or gas project are generated from the production and sale of both the primary fuel as well as any co-products. The present value of expected revenues measured at the wellhead from the production of a representative project is defined as the summation of yearly expected net wellhead price[1]

[1] The DCF methodology accommodates price expectations that are myopic, adaptive, or perfect. The default is myopic expectations, so prices are assumed to be constant throughout the economic evaluation period.

times expected production[2] discounted at an assumed rate. The discount rate used to evaluate private investment projects typically represents a weighted average cost of capital (WACC), i.e., a weighted average of both the cost of debt and the cost of equity.

Fundamentally, the formula for the WACC is straightforward.

$$\mathrm{WACC} = \frac{D}{D+E} * R_D * (1-t) + \frac{E}{D+E} * R_E \tag{A-2}$$

where D = market value of debt, E = market value of equity, t = corporate tax rate, R_D = cost of debt, and R_E = cost of equity. Because the drilling projects being evaluated are long term in nature, the values for all variables in the WACC formula are long run averages.

The WACC calculated using the formula given above is a nominal one. The real value can be calculated by

$$\mathrm{disc} = \frac{(1+\mathrm{WACC})}{(1+\pi_e)} - 1 \tag{A-3}$$

where π_e = expected inflation rate. The expected rate of inflation over the forecasting period is measured as the average annual rate of change in the U.S. GDP deflator over the forecasting period using the forecasts of the GDP deflator from the Macro Module (MC_JPGDP).

The present value of expected revenue for either the primary fuel or its co-product is calculated as follows:

$$\mathrm{PVREV}_{T,k} = \sum_{t=T}^{T+n}\left[Q_{t,k} * \lambda * P_{t,k} * \left[\frac{1}{1+\mathrm{disc}}\right]^{t-T}\right], \lambda = \begin{cases} 1 \text{ if primary fuel} \\ \mathrm{COPRD} \text{ if secondary fuel} \end{cases} \tag{A-4}$$

where,

k	=	fuel type (oil or natural gas)
T	=	time period
n	=	number of years in the evaluation period
disc	=	discount rate
Q	=	expected production volumes
P	=	expected net wellhead price
COPRD	=	co-product factor.[3]

Net wellhead price is equal to the market price minus any transportation costs. Market prices for oil and gas are defined as follows: the price at the receiving refinery for oil, the first purchase price for onshore natural gas, the price at the coastline for offshore natural gas, and the price at the Canadian border for Alaskan gas.

[2]Expected production is determined outside the DCF subroutine. The determination of expected production is described in Chapter 3.

[3]The OGSM determines coproduct production as proportional to the primary product production. COPRD is the ratio of units of coproduct per unit of primary product.

The present value of the total expected revenue generated from the representative project is

$$PVTREV_T = PVREV_{T,1} + PVREV_{T,2} \tag{A-5}$$

where

$PVREV_{T,1}$	=	present value of expected revenues generated from the primary fuel
$PVREV_{T,2}$	=	present value of expected revenues generated from the secondary fuel.

Present Value of Expected Royalty Payments

The present value of expected royalty payments (PVROY) is simply a percentage of expected revenue and is equal to

$$PVROY_T = ROYRT_1 * PVREV_{T,1} + ROYRT_2 * PVREV_{T,2} \tag{A-6}$$

where

ROYRT	=	royalty rate, expressed as a fraction of gross revenues.

Present Value of Expected Production Taxes

Production taxes consist of ad valorem and severance taxes. The present value of expected production tax is given by

$$\begin{aligned} PVPRODTAX_T = {} & PRREV_{T,1} * (1 - ROYRT_1) * PRDTAX_1 + PVREV_{T,2} \\ & *(1 - ROYRT_2) * PRODTAX_2 \end{aligned} \tag{A-7}$$

where

PRODTAX	=	production tax rate.

PVPRODTAX is computed as net of royalty payments because the investment analysis is conducted from the point of view of the operating firm in the field. Net production tax payments represent the burden on the firm because the owner of the mineral rights generally is liable for his/her share of these taxes.

Present Value of Expected Costs

Costs are classified within the OGSM as drilling costs, lease equipment costs, other capital costs, operating costs (including production facilities and general/administrative costs), and abandonment costs. These costs differ among successful exploratory wells, successful developmental wells, and dry holes. The present value calculations of the expected costs are computed in a similar manner as PVREV (i.e., costs are discounted at an assumed rate and then summed across the evaluation period).

Present Value of Expected Drilling Costs

Drilling costs represent the expenditures for drilling successful wells or dry holes and for equipping successful wells through the Christmas tree installation.[4] Elements included in drilling costs are labor,

[4]The Christmas tree refers to the valves and fittings assembled at the top of a well to control the fluid flow.

material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. The present value of expected drilling costs is given by

$$\begin{aligned} PVDRILLCOST_T = \sum_{t=T}^{T+n} \Bigg[\Big[& COSTEXP_T * SR_1 * NUMEXP_t + COSTDEV_T * SR_2 * NUMDEV_t \\ & + COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t \\ & + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \Big] * \left(\frac{1}{1 + disc} \right)^{t-T} \Bigg] \end{aligned} \tag{A-8}$$

where

COSTEXP	=	drilling cost for a successful exploratory well
SR	=	success rate (1=exploratory, 2=developmental)
COSTDEV	=	drilling cost for a successful developmental well
COSTDRY	=	drilling cost for a dry hole (1=exploratory, 2=developmental).
NUMEXP	=	number of exploratory wells drilled in a given period
NUMDEV	=	number of developmental wells drilled in a given period.

The number and schedule of wells drilled for an oil or gas project are supplied as part of the assumed production profile. This is based on historical drilling activities.

Present Value of Expected Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a drilled lease. Three categories of costs are included: producing equipment, the gathering system, and processing equipment. Producing equipment costs include tubing, rods, and pumping equipment. Gathering system costs consist of flowlines and manifolds. Processing equipment costs account for the facilities utilized by successful wells.

The present value of expected lease equipment cost is

$$PVEQUIP_T = \sum_{t=T}^{T+n} \left[EQUIP_t * (SR_1 * NUMEXP_t + SR_2 * NUMDEV_t) * \left[\frac{1}{1 + disc} \right]^{t-T} \right] \tag{A-9}$$

where

EQUIP	=	lease equipment costs per well.

Present Value of Other Expected Capital Costs

Other major capital expenditures include the cost of gravel pads in Alaska, and offshore platforms. These costs are exclusive of lease equipment costs. The present value of other expected capital costs is calculated as

$$PVKAP_T = \sum_{t=T}^{T+n} \left[KAP_t * \left[\frac{1}{1 + disc} \right]^{t-T} \right] \tag{A-10}$$

where

KAP = other major capital expenditures, exclusive of lease equipment.

Present Value of Expected Operating Costs

Operating costs include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

Total operating cost in time t is calculated by multiplying the cost of operating a well by the number of producing wells in time t. Therefore, the present value of expected operating costs is as follows:

$$PVOPCOST_T = \sum_{t=T}^{T+n} \left[OPCOST_t * \sum_{k=1}^{t} \left[SR_1 * NUMEXP_k + SR_2 * NUMDEV_k \right] * \left(\frac{1}{1+disc} \right)^{t-T} \right] \quad (A\text{-}11)$$

where

OPCOST = operating costs per well.

Present Value of Expected Abandonment Costs

Producing facilities are eventually abandoned and the cost associated with equipment removal and site restoration is defined as

$$PVABANDON_T = \sum_{t=T}^{T+n} \left[COSTABN_t * \left[\frac{1}{1+disc} \right]^{t-T} \right] \quad (A\text{-}12)$$

where

COSTABN = abandonment costs.

Drilling costs, lease equipment costs, operating costs, abandonment costs, and other capital costs incurred in each individual year of the evaluation period are integral components of the following determination of State and Federal corporate income tax liability.

Present Value of Expected Income Taxes

An important aspect of the DCF calculation concerns the tax treatment. All expenditures are divided into depletable,[5] depreciable, or expensed costs according to current tax laws. All dry hole and operating costs are expensed. Lease costs (i.e., lease acquisition and geological and geophysical costs) are capitalized and then amortized at the same rate at which the reserves are extracted (cost depletion). Drilling costs are split between tangible costs (depreciable) and intangible drilling costs (IDC's) (expensed). IDC's include

[5]The DCF methodology does not include lease acquisition or geological & geophysical expenditures because they are not relevant to the incremental drilling decision.

wages, fuel, transportation, supplies, site preparation, development, and repairs. Depreciable costs are amortized in accord with schedules established under the Modified Accelerated Cost Recovery System (MACRS).

Key changes in the tax provisions under the tax legislation of 1988 include the following:

- Windfall Profits Tax on oil was repealed,
- Investment Tax Credits were eliminated, and
- Depreciation schedules shifted to a Modified Accelerated Cost Recovery System.

Tax provisions vary with type of producer (major, large independent, or small independent) as shown in Table A-1. A major oil company is one that has integrated operations from exploration and development through refining or distribution to end users. An independent is any oil and gas producer or owner of an interest in oil and gas property not involved in integrated operations. Small independent producers are those with less than 1,000 barrels per day of production (oil and gas equivalent). The present DCF methodology reflects the tax treatment provided by current tax laws for large independent producers.

The resulting present value of expected taxable income (PVTAXBASE) is given by:

$$\mathrm{PVTAXBASE}_T = \sum_{t=T}^{T+n} \left[\left(\mathrm{TREV}_t - \mathrm{ROY}_t - \mathrm{PRODTAX}_t - \mathrm{OPCOST}_t - \mathrm{ABANDON}_t - \mathrm{XIDC}_t - \mathrm{AIDC}_t - \mathrm{DEPREC}_t - \mathrm{DHC}_t\right) * \left(\frac{1}{1+\mathrm{disc}}\right)^{t-T} \right] \tag{A-13}$$

where

T	=	year of evaluation
t	=	time period
n	=	number of years in the evaluation period
TREV	=	expected revenues
ROY	=	expected royalty payments
PRODTAX	=	expected production tax payments
OPCOST	=	expected operating costs
ABANDON	=	expected abandonment costs
XIDC	=	expected expensed intangible drilling costs
AIDC	=	expected amortized intangible drilling costs[6]
DEPREC	=	expected depreciable tangible drilling, lease equipment costs, and other capital expenditures
DHC	=	expected dry hole costs
disc	=	expected discount rate.

TREV_t, ROY_t, $\mathrm{PRODTAX}_t$, OPCOST_t, and $\mathrm{ABANDON}_t$ are the undiscounted individual year values. The following sections describe the treatment of expensed and amortized costs for the purpose of determining corporate income tax liability at the State and Federal level.

[6]This variable is included only for completeness. For large independent producers, all intangible drilling costs are expensed.

Expected Expensed Costs

Expensed costs are intangible drilling costs, dry hole costs, operating costs, and abandonment costs. Expensed costs and taxes (including royalties) are deductible from taxable income.

Expected Intangible Drilling Costs

For large independent producers, all intangible drilling costs are expensed. However, this is not true across the producer category (as shown in Table A-1). In order to maintain analytic flexibility with respect to changes in tax provisions, the variable XDCKAP (representing the portion of intangible drilling costs that must be depreciated) is included.

Table A-1. Tax Treatment in Oil and Gas Production by Category of Company Under Current Tax Legislation

Costs by Tax Treatment	Majors	Large Independents	Small Independents
Depletable Costs	**Cost Depletion** G&G[a] Lease Acquisition	**Cost Depletion**[b] G&G Lease Acquisition	**Maximum of Percentage or Cost Depletion** G&G Lease Acquisition
Depreciable Costs	**MACRS**[c] Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s **5-year SLM**[d] 20 percent of IDC=s	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s
Expensed Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs

[a]Geological and geophysical.
[b]Applicable to marginal project evaluation; first 1,000 barrels per day depletable under percentage depletion.
[c]Modified Accelerated Cost Recovery System; the period of recovery for depreciable costs will vary depending on the type of depreciable asset.
[d]Straight Line Method.

Expected expensed IDC's are defined as follows:

$$\begin{aligned} XIDC_t = {} & COSTEXP_T * (1 - EXKAP) * (1 - XDCKAP) * SR_1 * NUMEXP_t \\ & + COSTDEV_T * (1 - DVKAP) * (1 - XDCKAP) * SR_2 * NUMDEV_t \end{aligned} \tag{A-14}$$

where

COSTEXP	=	drilling cost for a successful exploratory well
EXKAP	=	fraction of exploratory drilling costs that are tangible and must be depreciated
XDCKAP	=	fraction of intangible drilling costs that must be depreciated[7]
SR	=	success rate (1=exploratory, 2=developmental)
NUMEXP	=	number of exploratory wells
COSTDEV	=	drilling cost for a successful developmental well
DVKAP	=	fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV	=	number of developmental wells.

If only a portion of IDC's are expensed (as is the case for major producers), the remaining IDC's must be depreciated. The model assumes that these costs are recovered at a rate of 10 percent in the first year, 20 percent annually for four years, and 10 percent in the sixth year; this method of estimating the costs is referred to as the 5-year Straight Line Method (SLM) with half-year convention. If depreciable costs accrue when fewer than 6 years remain in the life of the project, the recovered costs are estimated using a simple straight line method over the remaining period.

Thus, the value of expected depreciable IDC's is represented by

$$\begin{aligned} AIDC_t = \sum_{j=\beta}^{t} \Big[&\big(COSTEXP_T * (1 - EXKAP) * XDCKAP * SR_1 * NUMEXP_j \\ &+ COSTDEV_T * (1 - DVKAP) * XDCKAP * SR_2 * NUMDEV_j\big) \\ &* DEPIDC_t * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j} \Big], \end{aligned} \tag{A-15}$$

$$\beta = \begin{cases} T \ \text{ for } t \le T + m - 1 \\ t - m + 1 \ \text{ for } \ t > T + m - 1 \end{cases}$$

where,

j	=	year of recovery
β	=	index for write-off schedule
DEPIDC	=	for t # n+T-m, 5-year SLM recovery schedule with half year convention; otherwise, 1/(n+T-t) in each period
infl	=	expected inflation rate[8]
disc	=	expected discount rate
m	=	number of years in standard recovery period.

AIDC will equal zero by default since the DCF methodology reflects the tax treatment pertaining to large independent producers.

[7]The fraction of intangible drilling costs that must be depreciated is set to zero as a default to conform with the tax perspective of a large independent firm.

[8]The write-off schedule for the 5-year SLM give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

Expected Dry Hole Costs

All dry hole costs are expensed. Expected dry hole costs are defined as

$$DHC_t = COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \qquad \text{(A-16)}$$

where

COSTDRY = drilling cost for a dry hole (1=exploratory, 2=developmental).

Total expensed costs in any year equals the sum of $XIDC_t$, $OPCOST_t$, $ABANDON_t$, and DHC_t.

Expected Depreciable Tangible Drilling Costs, Lease Equipment Costs and Other Capital Expenditures

Amortization of depreciable costs, excluding capitalized IDC's, conforms to the Modified Accelerated

Table A-2. MACRS Schedules
(Percent)

Year	3-year Recovery Period	5-year Recovery Period	7-year Recovery Period	10-year Recovery Period	15-year Recovery Period	20-year Recovery Period
1	33.33	20.00	14.29	10.00	5.00	3.750
2	44.45	32.00	24.49	18.00	9.50	7.219
3	14.81	19.20	17.49	14.40	8.55	6.677
4	7.41	11.52	12.49	11.52	7.70	6.177
5		11.52	8.93	9.22	6.93	5.713
6		5.76	8.92	7.37	6.23	5.285
7			8.93	6.55	5.90	4.888
8			4.46	6.55	5.90	4.522
9				6.56	5.91	4.462
10				6.55	5.90	4.461
11				3.28	5.91	4.462
12					5.90	4.461
13					5.91	4.462
14					5.90	4.461
15					5.91	4.462
16					2.95	4.461
17						4.462
18						4.461
19						4.462
20						4.461
21						2.231

Source: U.S. Master Tax Guide.

Cost Recovery System (MACRS) schedules. The schedules under differing recovery periods appear in Table A-2. The particular period of recovery for depreciable costs will conform to the specifications of the tax code. These recovery schedules are based on the declining balance method with half year convention. If depreciable costs accrue when fewer years remain in the life of the project than would allow for cost recovery over the standard period, then costs are recovered using a straight line method over the remaining period.

The expected tangible drilling costs, lease equipment costs, and other capital expenditures is defined as

$$
\begin{aligned}
DEPREC_t = \sum_{j=\beta}^{t} \Big[\big[& (COSTEXP_T * EXKAP + EQUIP_T) * SR_1 * NUMEXP_j \\
& + (COSTDEV_T * DVKAP + EQUIP_T) * SR_2 * NUMDEV_j + KAP_j \big] \\
& * DEP_{t-j+1} * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j} \Big],
\end{aligned}
\tag{A-17}
$$

$$
\beta = \begin{cases} T \ \text{for}\ t \le T + m - 1 \\ t - m + 1 \ \text{for}\ t > T + m - 1 \end{cases}
$$

where

j	=	year of recovery
β	=	index for write-off schedule
m	=	number of years in standard recovery period
COSTEXP	=	drilling cost for a successful exploratory well
EXKAP	=	fraction of exploratory drilling costs that are tangible and must be depreciated
EQUIP	=	lease equipment costs per well
SR	=	success rate (1=exploratory, 2=developmental)
NUMEXP	=	number of exploratory wells
COSTDEV	=	drilling cost for a successful developmental well
DVKAP	=	fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV	=	number of developmental wells drilled in a given period
KAP	=	major capital expenditures such as gravel pads in Alaska or offshore platforms, exclusive of lease equipment
DEP	=	for t # n+T-m, MACRS with half year convention; otherwise, 1/(n+T-t) in each period
infl	=	expected inflation rate[9]
disc	=	expected discount rate.

Present Value of Expected State and Federal Income Taxes

The present value of expected state corporate income tax is determined by

$$
PVSIT_T = PVTAXBASE_T * STRT \tag{A-18}
$$

where

PVTAXBASE	=	present value of expected taxable income (Equation A.14)
STRT	=	state income tax rate.

[9]Each of the write-off schedules give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

The present value of expected federal corporate income tax is calculated using the following equation:

$$PVFIT_T = PVTAXBASE_T * (1 - STRT) * FDRT \tag{A-19}$$

where

FDRT = federal corporate income tax rate.

Summary

The discounted cash flow calculation is a useful tool for evaluating the expected profit or loss from an oil or gas project. The calculation reflects the time value of money and provides a good basis for assessing and comparing projects with different degrees of profitability. The timing of a project's cash inflows and outflows has a direct affect on the profitability of the project. As a result, close attention has been given to the tax provisions as they apply to costs.

The discounted cash flow is used in each submodule of the OGSM to determine the economic viability of oil and gas projects. Various types of oil and gas projects are evaluated using the proposed DCF calculation, including single well projects and multi-year investment projects. Revenues generated from the production and sale of co-products also are taken into account.

The DCF routine requires important assumptions, such as assumed costs and tax provisions. Drilling costs, lease equipment costs, operating costs, and other capital costs are integral components of the discounted cash flow analysis. The default tax provisions applied to the costs follow those used by independent producers. Also, the decision to invest does not reflect a firm's comprehensive tax plan that achieves aggregate tax benefits that would not accrue to the particular project under consideration.

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Appendix C. Model Abstract

1. Model Name
   Oil and Gas Supply Module

2. Acronym
   OGSM

3. Description
   OGSM projects the following aspects of the crude oil and natural gas supply industry:
   - production
   - reserves
   - drilling activity
   - natural gas imports and exports

4. Purpose
   OGSM is used by the Oil and Gas Division in the Office of Integrated Analysis and Forecasting as an analytic aid to support preparation of projections of reserves and production of crude oil and natural gas at the regional and national level. The annual projections and associated analyses appear in the *Annual Energy Outlook* (DOE/EIA-0383) of the U.S. Energy Information Administration. The projections also are provided as a service to other branches of the U.S. Department of Energy, the Federal Government, and non-Federal public and private institutions concerned with the crude oil and natural gas industry.

5. Date of Last Update
   2010

6. Part of Another Model
   National Energy Modeling System (NEMS)

7. Model Interface References
   Coal Module
   Electricity Module
   Industrial Module
   International Module
   Natural Gas Transportation and Distribution Model (NGTDM)
   Macroeconomic Module
   Petroleum Market Module (PMM)

8. Official Model Representative
   Office: Integrating Analysis and Forecasting
   Division: Oil and Gas Analysis
   Model Contact: Dana Van Wagener
   Telephone: (202) 586-4725

9. Documentation Reference
   U.S. Department of Energy. 2009. *Documentation of the Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063, U.S. Energy Information Administration, Washington, DC.

10. Archive Media and Installation Manual
NEMS2010

11. Energy Systems Described
The OGSM projects oil and natural gas production activities for six onshore and three offshore regions as well as three Alaskan regions. Exploratory and developmental drilling activities are treated separately, with exploratory drilling further differentiated as new field wildcats or other exploratory wells. New field wildcats are those wells drilled for a new field on a structure or in an environment never before productive. Other exploratory wells are those drilled in already productive locations. Development wells are primarily within or near proven areas and can result in extensions or revisions. Exploration yields new additions to the stock of reserves, and development determines the rate of production from the stock of known reserves.

12. Coverage
Geographic: Six Lower 48 onshore supply regions, three Lower 48 offshore regions, and three Alaskan regions.
Time Units/Frequency: Annually 1990 through 2035
Product(s): Crude oil and natural gas
Economic Sector(s): Oil and gas field production activities

13. Model Features
Model Structure: Modular, containing four major components
- Onshore Lower 48 Oil and Gas Supply Submodule
- Offshore Oil and Gas Supply Submodule
- Alaska Oil and Gas Supply Submodule
- Oil Shale Supply Submodule

Modeling Technique: The OGSM is a hybrid econometric/discovery process model. Drilling activities in the United States are projected using the estimated discounted cash flow that measures the expected present value profits for the proposed effort and other key economic variables.
Special Features: Can run stand-alone or within the NEMS. Integrated NEMS runs employ short-term natural gas supply functions for efficient market equilibration.

14. Non-DOE Input Data
- Alaskan Oil and Gas Field Size Distributions - U.S. Geological Survey
- Alaska Facility Cost By Oil Field Size - U.S. Geological Survey
- Alaska Operating cost - U.S. Geological Survey
- Basin Differential Prices - Natural Gas Week, Washington, DC
- State Corporate Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
- State Severance Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
- Federal Corporate Tax Rate, Royalty Rate - U.S. Tax Code
- Onshore Drilling Costs - (1.) American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-2008)*, Washington, D.C.; (2.) Additional unconventional gas recovery drilling and operating cost data from operating companies
- Offshore Technically Recoverable Oil and Gas Undiscovered Resources - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
- Offshore Exploration, Drilling, Platform, and Production Costs - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
- Canadian Wells drilled - Canadian Association of Petroleum Producers. *Statistical Handbook*.

- Canadian Recoverable Resource Base - National Energy Board. *Canada's Conventional Natural Gas Resources: A Status Report,* Canada, April 2004.
- Canadian Reserves - Canadian Association of Petroleum Producers. *Statistical Handbook*.
- Unconventional Gas Resource Data - (1) USGS *1995 National Assessment of United States Oil and Natural Gas Resources*; (2) Additional unconventional gas data from operating companies
- Unconventional Gas Technology Parameters - (1) Advanced Resources International Internal studies; (2) Data gathered from operating companies

15. DOE Input Data
    - Onshore Lease Equipment Cost – U.S. Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2008)*, DOE/EIA-0815(80-08)
    - Onshore Operating Cost – U.S. Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2008)*, DOE/EIA-0815(80-08)
    - Emissions Factors – U.S. Energy Information Administration
    - Oil and Gas Well Initial Flow Rates – U.S. Energy Information Administration, Office of Oil and Gas
    - Wells Drilled – U.S. Energy Information Administration, Office of Oil and Gas
    - Expected Recovery of Oil and Gas Per Well – U.S. Energy Information Administration, Office of Oil and Gas
    - Oil and Gas Reserves – U.S. Energy Information Administration. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, (1977-2009), DOE/EIA-0216(77-09)

16. Computing Environment
    - Hardware Used: PC
    - Operating System: Windows 95/Windows NT/Windows XP
    - Language/Software Used: FORTRAN
    - Memory Requirement: Unknown
    - Storage Requirement: Unknown
    - Estimated Run Time: 287 seconds

17. Reviews conducted
    - Independent Expert Review of the Offshore Oil and Gas Supply Submodule - Turkay Ertekin from Pennsylvania State University; Bob Speir of Innovation and Information Consultants, Inc.; and Harry Vidas of Energy and Environmental Analysis , Inc., June 2004
    - Independent Expert Review of the Annual Energy Outlook 2003 - Cutler J. Cleveland and Robert K. Kaufmann of the Center for Energy and Environmental Studies, Boston University; and Harry Vidas of Energy and Environmental Analysis, Inc., June-July 2003
    - Independent Expert Reviews, Model Quality Audit; Unconventional Gas Recovery Supply Submodule - Presentations to Mara Dean (DOE/FE - Pittsburgh) and Ray Boswell (DOE/FE - Morgantown), April 1998 and DOE/FE (Washington, DC)

18. Status of Evaluation Efforts

    Not applicable

19. Bibliography

    See Appendix B of this document.

Appendix D. Output Inventory

Variable Name	Description	Unit	Classification	Passed To Module
OGANGTSMX	Maximum natural gas flow through ANGTS	BCF	NA	NGTDM
OGCCAPPRD	Coalbed Methane production from CCAP		17 OGSM/NGTDM regions	NGTDM
OGCOPRD	Crude production by oil category	MMbbl/day	10 OGSM reporting regions	Industrial
OGCOPRDGOM	Gulf of Mexico crude oil production	MMbbl/day	Shallow and deep water regions	Industrial
OGCOWHP	Crude wellhead price by oil category	87$/bbl	10 OGSM reporting regions	Industrial
OGCNQPRD	Canadian production of oil and gas	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGCNPPRD	Canadian price of oil and gas	oil:87$/ bbl gas:87$/ BCF	Fuel (oil, gas)	NGTDM
OGCORSV	Crude reserves by oil category	Bbbl	5 crude production categories	Industrial
OGCRDSHR	Crude oil shares by OGSM region and crude type	percent	7 OLOGSS regions	PMM
OGDNGPRD	Dry gas production	BCF	57 Lower 48 onshore & 6 Lower 48 offshore districts	PMM
OGELSCO	Oil production elasticity	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGELSHALE	Electricity consumed	Trillion Btu	NA	Industrial
OGELSNGOF	Offshore nonassociated dry gas production elasticity	fraction	3 Lower 48 offshore regions	NGTDM
OGELSNGON	Onshore nonassociated dry gas production elasticity	fraction	17 OGSM/NGTDM regions	NGTDM
OGEORFTDRL	Total footage drilled from CO2 projects	feet	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORINJWLS	Number of injector wells from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORNEWWLS	Number of new wells drilled from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORPRD	EOR production from CO2 projects	Mbbl	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORPRDWLS	Number of producing wells from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEOYAD	Unproved Associated-Dissolved gas resources	TCF	6 Lower 48 onshore regions	Industrial
OGEOYRSVON	Lower 48 Onshore proved reserves by gas category	TCF	6 Lower 48 onshore regions 5 gas categories	Industrial
OGEOYINF	Inferred oil and conventional NA gas reserves	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial

Variable Name	Description	Unit	Classification	Passed To Module
OGEOYRSV	Proved Crude oil and natural gas reserves	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGEOYUGR	Technically recoverable unconventional gas resources	TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGEOYURR	Undiscovered technically recoverable oil and conventional NA gas resources	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGGROWFAC	Factor to reflect expected future cons growth		NA	NGTDM
OGJOBS			NA	Macro
OGNGLAK	Natural Gas Liquids from Alaska	Mbbl/day	NA	PMM
OGNGPRD	Natural Gas production by gas category	TCF	10 OGSM reporting regions	Industrial
OGNGPRDGOM	Gulf of Mexico Natural Gas production	TCF	Shallow and deep water regions	Industrial
OGNGRSV	Natural gas reserves by gas category	TCF	12 oil and gas categories	Industrial
OGNGWHP	Natural gas wellhead price by gas category	87$/MCF	10 OGSM reporting regions	Industrial
OGNOWELL	Wells completed	wells	NA	Industrial
OGPCRWHP	Crude average wellhead price	87$/bbl	NA	Industrial
OGPNGEXP	NG export price by border	87$/MCF	26 Natural Gas border crossings	NGTDM
OGPNGWHP	Natural gas average wellhead price	87$/MCF	NA	Industrial
OGPPNGIMP	NG import price by border	87$/MCF	26 Natural Gas border crossings	NGTDM
OGPRCEXP	Adjusted price to reflect different expectation		NA	NGTDM
OGPRCOAK	Alaskan crude oil production	Mbbl	3 Alaska regions	NGTDM
OGPRDADOF	Offshore AD gas production	BCF	3 Lower 48 offshore regions	NGTDM
OGPRDADON	Onshore AD gas production	BCF	17 OGSM/NGTDM regions	NGTDM
OGPRDUGR	Lower 48 unconventional natural gas production	BCF	6 Lower 48 regions and 3 unconventional gas types	NGTDM
OGPRRCAN	Canadian P/R ratio	fraction	Fuels (oil, gas)	NGTDM
OGPRRCO	Oil P/R ratio	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGPRRNGOF	Offshore nonassociated dry gas P/R ratio	fraction	3 Lower 48 offshore regions	NGTDM
OGPRRNGON	Onshore nonassociated dry gas P/R ratio	fraction	17 OGSM/NGTDM regions	NGTDM
OGQANGTS	Gas flow at U.S. border from ANGTS	BCF	NA	NGTDM
OGQCRREP	Crude production by oil category	MMbbl	5 crude production categories	PMM
OGQCRRSV	Crude reserves	Bbbl	NA	Industrial
OGQNGEXP	Natural gas exports	BCF	6 US/Canada & 3 US/Mexico border crossings	NGTDM

Variable Name	Description	Unit	Classification	Passed To Module
OGQNGIMP	Natural gas imports	BCF	3 US/Mexico border crossings; 4 LNG terminals	NGTDM
OGQNGREP	Natural gas production by gas category	TCF	12 oil and gas categories	NGTDM
OGQNGRSV	Natural gas reserves	TCF	NA	Industrial
OGRADNGOF	Non Associated dry gas reserve additions, offshore	BCF	3 Lower 48 offshore regions	NGTDM
OGRADNGON	Non Associated dry gas reserve additions, onshore	BCF	17 OGSM/NGTDM regions	NGTDM
OGRESCAN	Canadian end-of-year reserves	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGRESCO	Oil reserves	MMB	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGRESNGOF	Offshore nonassociated dry gas reserves	BCF	3 Lower 48 offshore regions	NGTDM
OGRESNGON	Onshore nonassociated dry gas reserves	BCF	17 OGSM/NGTDM regions	NGTDM
OGSHALENG	Gas produced	BCF	NA	NGTDM
OGTAXPREM	Canadian tax premium	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGTECHON	Technology factors	BCF	3 cost categories, 6 fuel types	Industrial
OGWPTDM	Natural Gas wellhead price	87$/MCF	17 OGSM/NGTDM regions	NGTDM

Deloitte.

Made in America
The economic impact of LNG exports from the United States

A report by the Deloitte Center for Energy Solutions and Deloitte MarketPoint LLC

Deloitte Center for Energy Solutions

Contents

Deloitte MarketPoint applied its integrated North American Power, Coal, and World Gas Model to analyze the price and quantity impacts of LNG exports on the U.S. gas market. Given the model's assumptions, the World Gas Model projects a weighted-average price impact of $0.12/MMBtu on U.S. prices from 2016 to 2035 as a result of the 6 Bcfd of LNG exports. The $0.12/MMBtu increase represents a 1.7% increase in the projected average U.S. citygate gas price of $7.09/MMBtu over this time period. The projected impact on Henry Hub price is $0.22/MMBtu, significantly higher than the national average because of its close proximity to the prospective export terminals. The projected price impacts diminish with distance away from the Gulf. Distant market areas' projected price impacts are less than $0.10/MMBtu. Focusing solely on the Henry Hub or regional prices around the export terminals will greatly overstate the total impact on U.S. consumers.

The results show that the North American gas market is dynamic. If exports can be anticipated, then producers, midstream players, and consumers can act to mitigate the price impact. Producers will bring more supplies online, flows will be adjusted, and consumers will react to price change resulting from LNG exports.

Executive summary

Deloitte MarketPoint LLC ("DMP") is pleased to provide an independent assessment of the potential economic impacts of LNG exports from the United States. Exporters might benefit from selling to foreign buyers, but how would such exports adversely impact domestic consumers of natural gas? Increased competition for supplies and accelerated resource depletion will likely raise domestic prices, but by how much? Will the level of exports being considered raise prices enough to cause economic damage as some objectors contend? After all, natural gas is a depletable resource, and what is exported is made unavailable to domestic uses. Under the assumptions outlined in this paper, we shall see that the magnitude of domestic price increase that results from export of natural gas in the form of LNG is likely quite small.

Deloitte MarketPoint applied its integrated North American Power, Coal, and World Gas Model to analyze the price and quantity impacts of LNG exports on the U.S. gas market.

Some arguments in support of or objecting to LNG exports center around whether there are adequate resources to meet both domestic consumption and export volumes. That is, does the U.S. need the gas for its own consumption or does the U.S. possess sufficiently abundant gas volumes to provide for both domestic consumption and exports? In our view, this question only begins to address the export issue because simple comparisons of total available domestic resources to projected future consumption are insufficient to adequately analyze the economic impact of LNG exports. We believe the real issue is not only one of volume, but more of price impact. *If price is not significantly affected, then scarcity and shortage of supply are not significant issues.*

DMP applied its integrated North American Power, Coal, and World Gas Model ("WGM" or "Model") to analyze the price and quantity impacts of LNG exports on the U.S. gas market.[1] The WGM projects monthly prices and quantities over a 30-year time horizon based on rigorous adherence to accepted microeconomic theories. It includes disaggregated representations of North America, Europe, and other major global markets. The WGM computes prices and quantities simultaneously across multiple markets and across multiple time points. Unlike many other models which compute prices and quantities assuming all parties work together to achieve a single global objective, the WGM applies fundamental economic theories to represent self-interested decisions made by each market "agent" along every stage of the supply chain. More information can be obtained from DMP.

Vital to this analysis, the WGM represents fundamental producer decisions regarding when and how much reserves to add given the producer's resource endowments and anticipated forward prices. This supply-demand dynamic is particularly important in analyzing the impact of demand changes (e.g., LNG exports) because without it, the answer will likely greatly overestimate the impact of demand changes by not adequately considering supply dynamics. Indeed, producers will anticipate the export volumes and resulting increased prices to make production decisions accordingly. LNG exporters might back up their multibillion dollar projects with long-term domestic supply contracts, but even if they do not, producers will anticipate and incorporate the demand growth in their production decisions. Missing this supply-demand dynamic is tantamount to assuming the market will be surprised and unprepared for the volume of exports and have to ration fixed supplies to meet the required volumes. Static models assume a fixed supply volume (i.e., productive capacity) during each time period and therefore are prone to overestimate the price impact of a demand change. Typically, users have to override this lack of supply response by manually adjusting supply to meet demand. Instead, the WGM uses sophisticated depletable resource logic in which today's drilling decisions affect tomorrow's price, and tomorrow's price affects today's drilling decisions. It captures the market dynamics between suppliers and consumers.

[1] In this document, "LNG exports" refers to the volume of exports from the three Gulf Coast terminals that have applied for a license to export LNG.

Shale gas production has grown tremendously over the past several years. However, there is considerable debate as to how long this trend will continue and how much will be produced out of each shale gas basin. Rather than simply extrapolating past trends, the WGM projects production-based resource volumes and cost, future gas demand, particularly for power generation, and competition among various sources in each market area. It computes incremental sources to meet a change in demand and the resulting impact on price.

Based on our existing model and assumptions, which we will call the "Reference Case," we developed a second case, which we will call the LNG Export Case, to assess the impact of LNG exports. Both cases are identical except for the LNG export volumes. In the LNG Export Case we represented 6 billion cubic feet per day ("Bcfd") of LNG exports, approximately equal to the total volume of the three LNG export applications at Sabine Pass, Freeport, and Lake Charles LNG terminals. Since the WGM already represented these import LNG terminals, we only had to represent exports as incremental demands, each with a constant of 2 Bcfd demand, near each of the terminals. Comparing results of this second case to the Reference Case, we projected how much the exports would increase domestic prices and affect production and flows.

Given the model's assumptions, the WGM projects a weighted-average price impact of $0.12 per million British thermal units (MMBtu) on U.S. prices from 2016 to 2035 as a result of the 6 Bcfd of LNG exports. The $0.12/MMBtu increase represents a 1.7% increase in the projected average U.S. citygate gas price of $7.09/MMBtu over this time period. The projected impact on Henry Hub price is $0.22/MMBtu, significantly higher than the national average because of its close proximity to the prospective export terminals. The projected price impacts diminish with distance away from the Gulf. Distant market areas' projected price impacts are less than $0.10/MMBtu, such as the New York and Chicago areas. Focusing solely on the Henry Hub or regional prices around the export terminals will greatly overstate the total impact on the U.S. consumers.

The results show that the North American gas market is dynamic. If exports can be anticipated, and clearly they can with the public application process and long lead time required to construct a LNG liquefaction plant, then producers, midstream players, and consumers can act to mitigate the price impact. Producers will bring more supplies online, flows will be adjusted, and consumers will react to price change resulting from LNG exports.

Given the model's assumptions, the WGM projects a weighted-average price impact of $0.12/MMBtu on U.S. prices from 2016 to 2035.

Gas prices in the Eastern U.S., historically the highest priced region in North America, could be dampened by incremental shale gas production within the region. Eastern bases to Henry Hub are projected to sink under the weight of surging gas production from the Marcellus Shale. The Marcellus Shale is projected to dominate the Mid-Atlantic natural gas market, including New York, New Jersey, and Pennsylvania, meeting most of the regional demand and pushing gas through to New England and even to South Atlantic markets. Pipelines built to transport gas supplies from distant producing regions — such as the Rockies and the Gulf Coast — to Northeastern U.S. gas markets may face stiff competition. The expected result is displacement of volumes from the Gulf which would depress prices in the Gulf region. Combined with the growing shale gas production out of Haynesville and Eagle Ford, the Gulf region is projected to continue to have plentiful production and remain one of the lowest cost regions in North America.

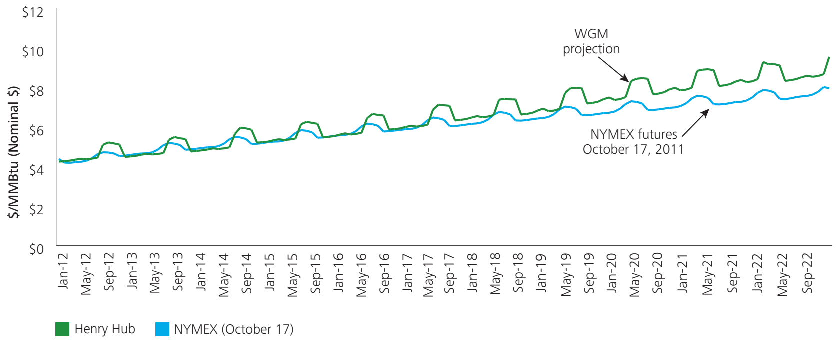
Overview of Deloitte MarketPoint Reference Case

The WGM Reference Case assumes a "business as usual" scenario including no new CO_2 emission regulations for power plants and no new regulations for hydrofracking operations in shale gas production. U.S. gas demand growth rates are consistent with the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") 2011 projection, except for power generation which is based on the DMP electricity model. (There is no intended advocacy or prediction of any events. Rather, we use these assumptions as a frame of reference. The impact of LNG exports could easily be tested against other scenarios, but the overall results would be rather similar for reasons articulated later in this document.)

In the Reference Case, natural gas prices are projected to rebound from current levels and continue to strengthen over the next two decades, although nominal prices do not return to the peak levels of the mid-to-late 2000s until after 2020. In real terms (i.e., constant 2011 dollars), benchmark U.S. Henry Hub spot prices increase from an annual average of $4.15 per MMBtu in 2011 to $6.00 per MMBtu in 2020, before rising to $7.16 per MMBtu in 2030 in the Reference Case. Our Henry Hub price forecast for 2011-2035 averages $6.23. Bear in mind that this is the Reference Case which includes no LNG exports.

Escalating real prices by an annual inflation rate (estimated at 2.0%[2]), yields nominal prices which can be compared to NYMEX futures prices. The WGM projection of monthly Henry Hub prices is compared to NYMEX futures prices as of October 17, 2011 in Figure 1. Prices are shown in nominal terms (i.e., dollars of the day including inflation). Near-term projections are fairly consistent, but in the longer term, projected prices from the WGM rise significantly higher than the NYMEX futures prices. On an annual average, the projected prices are a dollar higher than the NYMEX futures prices in the longer term.

Figure 1. Comparison between projected Henry Hub and NYMEX futures prices



[2] Average consumer price index over the past 10 years according to the Bureau of Labor Statistics.

The WGM projects the U.S. power sector to increase by about 50% over the next decade, accounting for nearly all of the projected future growth. Based on assumptions in the WGM, gas will become the fuel of choice for power generation.

One possible reason why the WGM forecasts prices higher than market expectation (i.e., NYMEX futures) is because the WGM's forecast of gas demand for power generation is considerably higher than the publicly available EIA forecast. Based on our electricity model projections, we forecast natural gas consumption for electricity generation to drive North American natural gas demand higher during the next two decades.

As shown in Figure 2, the DMP projected gas demand for U.S. power generation is far greater than the demand predicted by EIA's AEO 2011, which essentially forecasts no change. The WGM projects the U.S. power sector to increase by about 50% (approximately 10 Bcfd) over the next decade, accounting for nearly all of the projected future growth. Based upon assumptions in the WGM, gas will become the fuel of choice for power generation for a variety of reasons, including: tightening application of existing environmental regulations for mercury, NOx, and SOx; expectations of ample domestic gas supply at competitive gas prices; and the need to back up intermittent renewable sources such as wind and solar to ensure reliability. Like the EIA's AEO, our projection does not assume any new carbon legislation in the Reference Case.

Our electricity model, fully integrated with our WGM and coal model, contains a detailed representation of the North American electricity system including environmental emissions for key pollutants (CO_2, SOx, NOx, and mercury). The integrated structure of the models is shown in Figure 3. The electricity model projects electric generation capacity addition, dispatch and fuel burn based on competition among different types of power generators given a host of factors including plant capacities, fuel price, heat rates, variable costs, and environmental emissions costs. This integration captures global linkages and also inter-commodity linkages. Integrating gas and electricity is vitally important because U.S. natural gas demand growth is expected to be driven almost entirely by the electricity sector, which is predicted to grow at substantial rates. Hence, the WGM projection will be less favorable to the question of LNG export than if we had assumed a lower gas demand. The higher gas demand will push projection of price and quantity impacts of LNG export to be more "conservative." However, the real issue is not the absolute price of exported gas, but rather the price impact resulting from the LNG exports.

Figure 2. Diverse projections of the U.S. gas demand for power generation

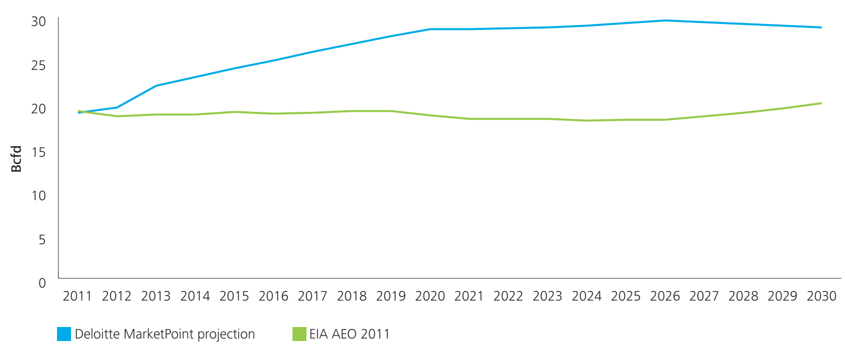
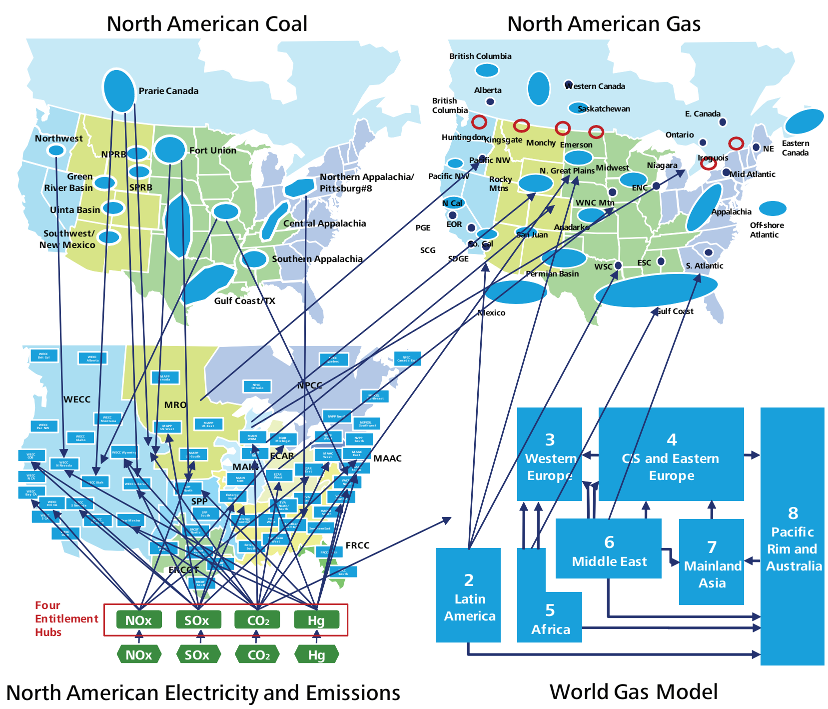


Figure 3. DMP North American representation



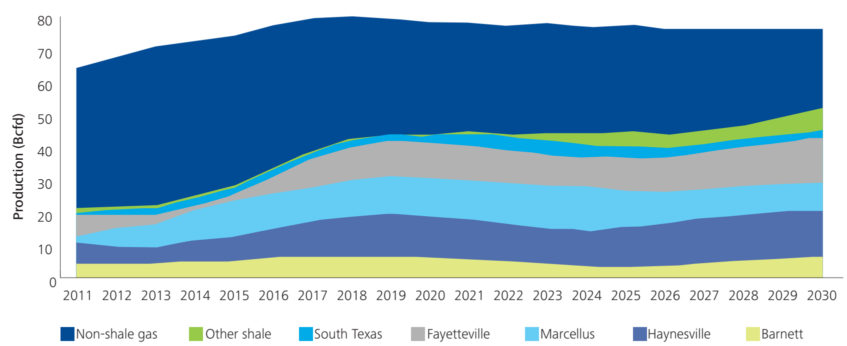
Buffering the price impact of LNG exports is the large domestic resource base, particularly shale gas, which we project to be an increasingly important component of domestic supply. As shown in Figure 4, the Reference Case projects shale gas production, particularly in the Marcellus Shale in Appalachia and the Haynesville Shale in Texas and Louisiana, to grow and eventually become the largest component of domestic gas supply. Increasing U.S. shale gas output bolsters total domestic gas production, which grows from about 64 Bcfd in 2011 to almost 80 Bcfd in 2018 before tapering off.

The projected growth in production from a large domestic resource base is a crucially important point. Many upstream gas industry observers today believe that there is a very large quantity of gas available to be produced in the shale regions of North America at a more or less constant price. This would imply that they also believe that natural gas supply is highly "elastic," i.e., the supply curve is very flat.

Gas production in Canada is projected to decline over the next several years, reducing exports to the U.S. and continuing the recent slide in production out of the Western Canadian Sedimentary Basin. However, Canadian production is projected to ramp up in the later part of this decade with increased production out of the Horn River and Montney shale gas plays in Western Canada. Further into the future, the Mackenzie Delta pipeline may begin making available supplies from Northern Canada. Increased Canadian production makes more gas available for export to the U.S. The North American natural gas system is highly integrated so Canadian supplies can generally access U.S. markets when economic. This increase in available gas for export to the U.S. could be supplemented even more if the Alaskan Gas Pipeline were to penetrate Alberta, but that would likely not happen within the time horizon of this scenario and is thus not considered.

Increasing production from major shale gas plays, many of which are not located in traditional gas-producing areas, is projected to transform historical basis relationships during the next two decades. Varying rates of regional gas demand growth, the advent of new natural gas infrastructure, and evolving gas flows may also contribute to changes in regional basis, though to a lesser degree. This is a very important point as well. If LNG is exported from

Figure 4. U.S. gas production by type



one particular geographic point, the entire eastern part of the United States reorients production and flows and basis differentials change substantially. Basis differentials are not fixed and invariant to LNG exports or other demand changes. On the contrary, basis differentials adjust to LNG volumes and help ensure economically efficient backfill and efficient prices. The advent of large quantities of shale gas in heretofore nonproducing areas will cause the basis to those areas to fall. The increased supply also will make more gas available for export and help mitigate the price increases due to exports.

Most notably, gas prices in the Eastern U.S., historically the highest priced region in North America, could be dampened by incremental shale gas production within the region. Eastern bases to Henry Hub are projected to sink under the weight of surging gas production from the Marcellus Shale. The Marcellus Shale is projected to dominate the Mid-Atlantic natural gas market, including New York, New Jersey, and Pennsylvania, meeting most of the regional demand and pushing gas through to New England and even to South Atlantic markets. Pipelines built to transport gas supplies from distant producing regions — such as the Rockies and the Gulf Coast — to Northeastern U.S. gas markets may face stiff competition. The expected result is displacement of volumes from the Gulf which would depress prices in the Gulf region. Combined with the growing shale gas production out of Haynesville and Eagle Ford, the Gulf region is projected to continue to have plentiful production and remain one of the lowest cost regions in North America.

Given our basic assumptions, the WGM projects LNG exports will cause a volume weighted-average price impact of $0.12/MMBtu on U.S. citygate prices from 2016 to 2035 as a result of the assumed 6 Bcfd of LNG exports out of the three Gulf Coast terminals. The $0.12/MMBtu increase represents a 1.7% increase in the projected average U.S. citygate gas price of $7.09/MMBtu over this time period. The projected increase in Henry Hub gas price is $0.22/MMBtu during this period. It is important to note the variation in price impact by location. The WGM projects that the impact at the Henry Hub will be much greater than the impact in other markets more distant from export terminals.

Potential impact of LNG exports

Given our basic assumptions, the WGM projects LNG exports will cause a volume weighted-average price impact of $0.12/MMBtu on U.S. citygate prices from 2016 to 2035 as a result of the assumed 6 Bcfd of LNG exports out of the three Gulf Coast terminals. The $0.12/MMBtu increase represents a 1.7% increase in the projected average U.S. citygate gas price of $7.09/MMBtu over this time period. The projected increase in Henry Hub gas price is $0.22/MMBtu during this period. It is important to note the variation in price impact by location. The WGM projects that the impact at the Henry Hub will be much greater than the impact in other markets more distant from export terminals.

To put the impact in perspective, Figure 5 shows the price impact on top of projected Reference Case U.S. average citygate prices over a 20-year period. The height of both bars represents the projected price with LNG exports.

The WGM's projected price impact might not be as large as some might expect because that is not what they observe in the short term. For example, even a 1 Bcfd increase in demand during a peak winter day can cause spot prices to shoot up.

However, in this analysis we are considering long-term impacts, when changes in supply and demand can be anticipated. Unlike short-term markets, in which supply and demand are both largely fixed, both supply and demand are far more elastic in the long term. Producers can develop more reserves in anticipation of demand growth, such as LNG exports. Indeed, LNG export projects will likely be backed by long-term supply contracts, as well as long-term contracts with buyers. There will be ample notice and time in advance of the exports to make supplies available. The price impact is then determined by how supply costs will change as a result of more rapid depletion of domestic resources.

As previously stated, the projected impact of LNG exports on price varies by location, as shown in Figure 6. The price impact attenuates with distance from the LNG export terminals. The impact is greatest at the Henry Hub, situated near all of the export terminals, about $0.22/MMBtu on average from 2016 to 2035. The impact at the Houston Ship Channel is nearly as much, about $0.20/MMBtu.

By the time you move to downstream markets, such as Illinois, New York, and California, the projected price impact is generally about $0.10/MMBtu or less. If we weight the price impact in each market by the volume of gas demand, we can compute a weighted average price impact for the U.S. of $0.12/MMBtu.

This analysis illustrates the interconnectivity of the North American system and the need to analyze not only Henry Hub and other price points near export terminals, but prices throughout the U.S. in order to fairly gauge the impacts from LNG exports. Analyses that focus just on Henry Hub prices will likely overstate the impact.

Figure 5: Impact of LNG exports on average U.S. citygate gas prices

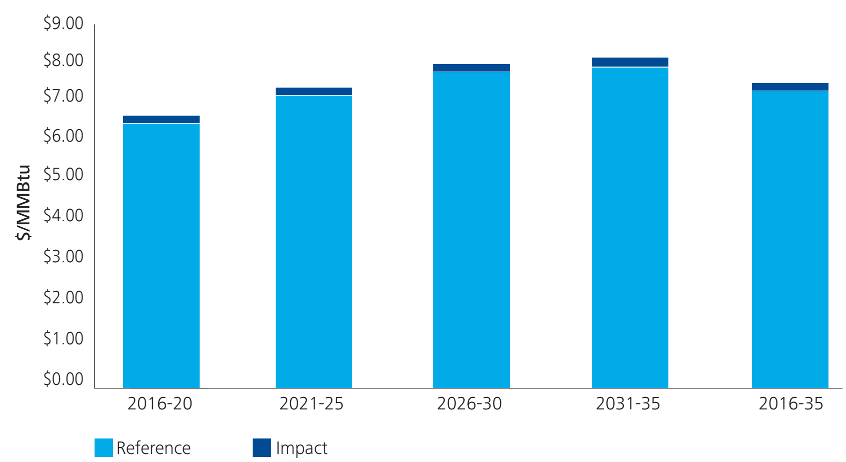


Figure 6: Price impact varies by location (average 2016-35)

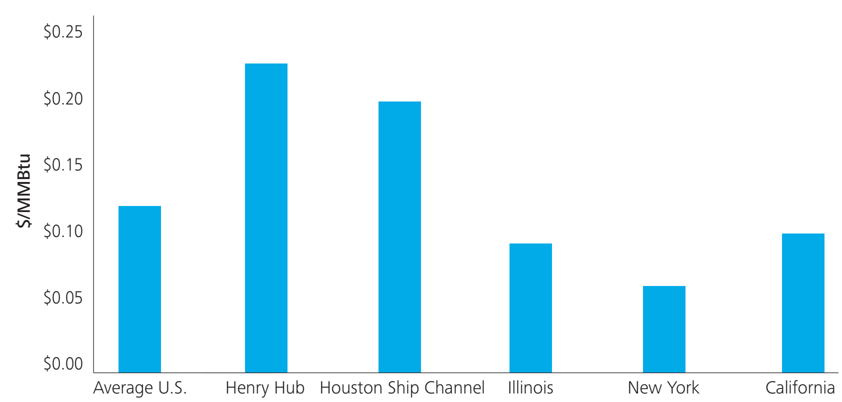


Figure 7 shows the aggregate U.S. supply curve, including Alaska and all types of gas formations, assumed in the WGM. It plots the volumes of reserve additions available at different all-in marginal capital costs, including financing, return on equity, and taxes. The marginal capital cost is equivalent to the wellhead price necessary to induce a level of investment required to bring the estimated volumes on line. The WGM includes over 100 different supply nodes representing the geographic and geologic diversity of domestic supply basins. The supply data is based on publicly available documents and discussions with credible sources such as the United States Geological Survey, National Petroleum Council, Potential Gas Committee, and the Department of Energy's EIA.

The area of the supply curve that matters most is the section below $6/MMBtu of capital cost because wellhead prices are projected to fall under this level during most of the time horizon considered. These are the volumes that are projected to be produced over the next couple of decades. The Reference Case estimates about 1,200 trillion cubic feet (Tcf) available at wellhead prices below $6/MMBtu. To put the LNG export volumes into proper perspective, it will accelerate depletion of the domestic resource base, estimated to include about 1,200 Tcf at prices below $6/MMBtu in all-in capital cost, by 2.2 Tcf per year (equivalent to 6 Bcfd). Alternatively, the 2.2 Tcf represents an increase in demand of about 8% to the projected demand of 26 Tcf by the time exports are assumed to commence in 2016. The point is not to downplay the export volume, but to put exports into perspective versus the overall available supply base. The results of this analysis demonstrate that the magnitude of the assumed total LNG exports is substantial on its own, but not very significant relative to the entire U.S. resource base or total U.S. demand.

In the WGM, supply and price are inextricably linked. With regard to the potential impact of LNG exports, the absolute price is not the driving factor but rather the shape of the aggregate supply curve which determines the price impact. Figure 8 depicts how demand increase affects price. Incremental demand pushes out the demand curve, causing it to intersect the supply curve at a higher point. Since the supply curve is fairly flat in the area of demand, the price impact is fairly small. The massive shale gas resources have flattened the U.S. supply curve. It is the shape of the aggregate supply curve that really matters.

Figure 7. Aggregate U.S. natural gas supply curve

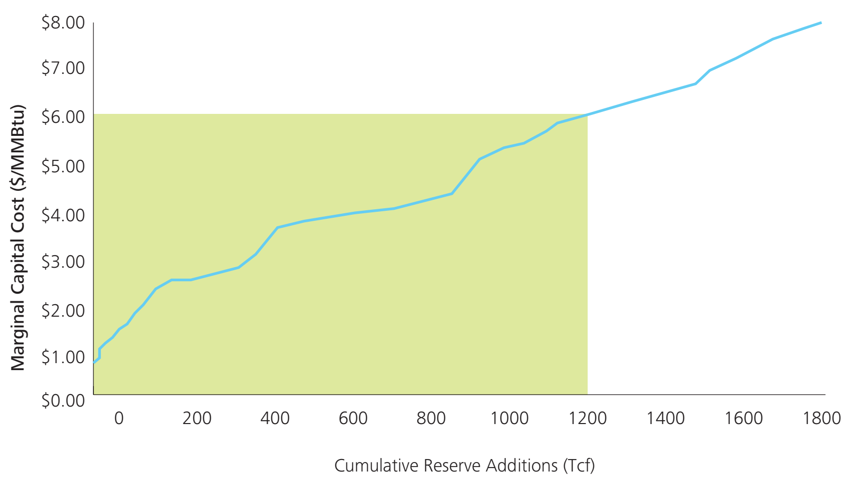
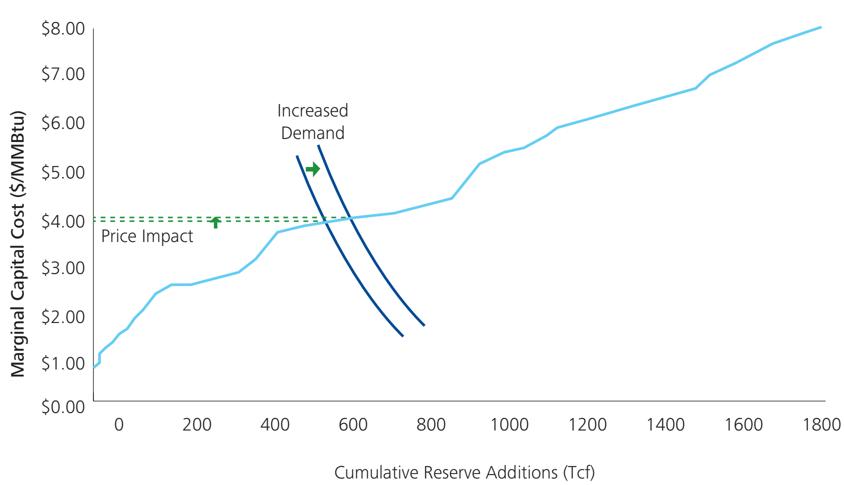


Figure 8: Impact of higher demand on price



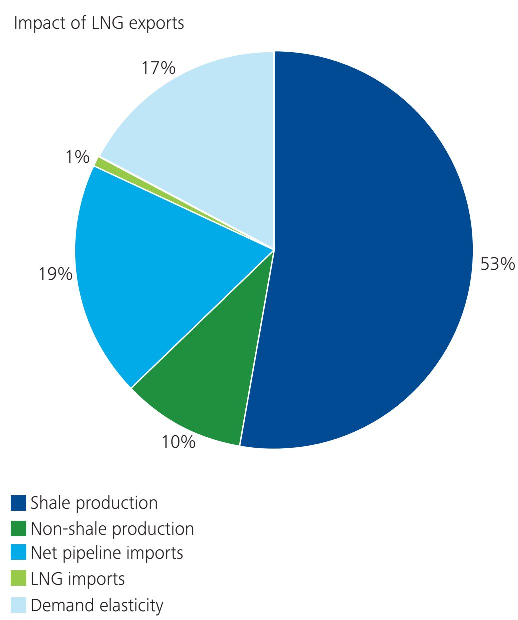
If that is the case, leftward and rightward movements in the demand curve (where such leftward and rightward movements would be volumes of LNG export) cut through the supply curve at pretty much the same price. Flat, elastic supply means that the price of domestic natural gas is increasingly and continually determined by supply issues (e.g., production cost). Given that there is a significant quantity of domestic gas available at modest production costs, the export of 6 Bcfd of LNG should not significantly increase the price of domestic gas because it should not dramatically increase the production cost of domestic gas.

The projected sources of incremental supply used to meet the assumed export volumes come from multiple sources, including domestic resources (both shale gas and non-shale gas), import volumes, and demand elasticity. As shown in Figure 9, the bulk of the incremental volumes come from shale gas production. Including non-shale gas production, the domestic production contributes 63% of the total incremental volume. Net pipeline imports, comprised mostly of imports from Canada, contribute another 19%. Higher U.S. prices would be expected to induce greater Canadian production, primarily from Horn River and Montney shale gas resources, making gas available for export to the U.S. The U.S. net exports to Mexico decline slightly as higher cost of U.S. supplies will prompt more Mexican production and reduce the need for U.S. exports to Mexico. Higher gas prices are also projected to trigger demand elasticity so less gas is consumed, representing about 17% of the incremental volume. Most of the reduction in gas consumption comes from the power sector as higher gas prices incentivize greater utilization of generators burning other types of fuels.

Finally, there is a small increment, 1%, coming from LNG imports. Having both LNG imports and exports is not necessarily contradictory since there is variation in price by terminal (e.g., Everett terminal near Boston historically has much higher prices than the Gulf terminals) and by time. The WGM projects seasonal arbitrage of global LNG flows. U.S. LNG imports are expected to be higher during summer periods as LNG shippers take advantage of plentiful storage capacity and large summer load for power generation in the U.S. and weaken during the winter when European and Asian demands peak.

An important point to bear in mind is that the North American natural gas market is highly integrated and all segments will work together to mitigate price impacts of demand changes.

Figure 9: Projected sources of incremental volume



Responses to raised concerns about LNG exports

In response to LNG export applications to the DOE made by several entities to date, some concerns have been raised regarding the viability of exports and the impact they may have on the U.S. gas market. The opposing arguments to LNG exports center around two main points: (i) allowing exports will cause U.S. gas prices to rise to levels equal to world gas prices, and (ii) exports should be prohibited in order to suppress domestic prices because suppressing domestic prices is good for employment and the U.S. economy. These two main points have prompted parties to raise more specific concerns and questions which we will address one at a time. Based on the WGM analysis conducted and based on our knowledge and experience, DMP provides the following observations in response to these concerns.

Concern: Contribution of shale gas to U.S. market could be grossly overestimated.

DMP Analysis: Abundant shale gas resources and commitment by energy majors to develop those reserves will likely ensure strong future growth of shale gas production.

Despite the rapid growth in shale gas production during the past several years, there is still some degree of skepticism about how long the trend will continue. The EIA forecasts shale gas will comprise 47% of total U.S. production in 2035, more than double the 23 percent share in 2011.[3] Our Reference Case forecasts that shale gas will become the dominant domestic source, hitting 50% as early as 2020. There is little debate over the massive volumes of shale gas. The debate is really over the production cost of shale gas. Some have estimated massive volumes to be available at very low prices (under $4/MMBtu). The shale gas supply curves in the WGM are less optimistic and represent diversity of shale gas plays, including some in "sweet spots" with very low production costs, but more in higher cost areas. The WGM supply curves were developed based on best available data and talking with leading supply experts from industry and governmental agencies.

The price forecast from the WGM based on the various assumptions reflects the long-run marginal cost of domestic supplies and is higher in the long term than the current forward price curves. Regardless of the exact share of total production, many expect shale gas to be an important component of domestic supply and prices will reflect production costs. Higher shale gas production cost estimates do not necessarily mean that shale gas will not be produced because prices will tend to rise in order to sustain their development.

Another factor that will help maintain the growth in shale gas development is the huge amount of capital that companies, particularly the majors, have poured into acquiring shale gas acreage and developing fields. The capital expenditures represent sunk costs and lower the marginal cost of future production. That is, the incremental cost of production is lower because part of the total cost has already been paid. Some examples of major expenditures are:

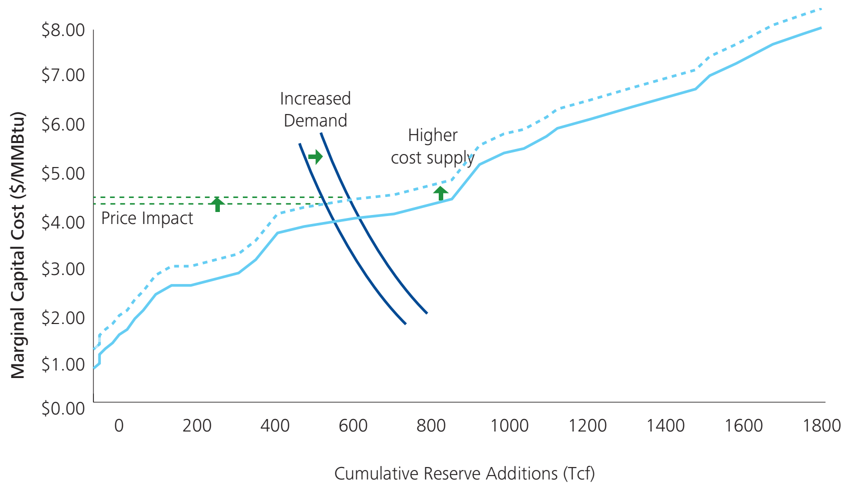
- ExxonMobil paid $34.9 billion to acquire XTO, which specialized in shale gas development, and later purchased two small shale gas exploration companies (Bloomberg, June 9, 2011).
- Chevron acquired Atlas Energy Inc. and its 622,000 acres in the Marcellus Shale for $3.58 billion and subsequently purchased additional acreage from smaller operators (Bloomberg, May 4, 2011).
- Shell acquired East Resources for $4.7 billion to double its reserves of shale gas (Bloomberg, May 28, 2010).
- Statoil signed deals with Chesapeake and Talisman for shares in jointed development of shale gas plays with these companies (Reuters, October 10, 2010).

Not only are these investments large, but the arrival of majors signals a new era in the development of shale gas. Unlike in the past when smaller independent companies worked shale gas fields in response to high prices, energy majors have the resources to remain committed to development through the vacillations of gas prices. They have staying power. Furthermore, they have the resources to invest in continued improvements of shale gas technologies and procedures. Their involvement will likely continue to drive down the cost of shale gas production, making more volumes available economically.

[3] EIA Annual Energy Outlook 2011 with Projections to 2035, p.2.

Even if shale gas production does not reach the projected levels because costs turn out to be higher than estimated, it does not necessarily mean that the impact of LNG exports would be much higher. Lower shale gas production would likely be the result of the discovery of another, more economic, source of supply. Very important, it is the shape of the supply curve, rather than the absolute cost level, that determines the price impact. Figure 10 illustrates that simply having a higher supply cost estimate (i.e., shifting the supply curve up) does not necessarily imply a greater price impact from a demand change.

Figure 10: Impact of higher cost supply curve



Concern: High level of uncertainty that shale gas can be produced as modeled due to concerns including regulatory issues, access issues, and environmental issues.

DMP Analysis: Regulations will likely push best practices already adopted by leading companies and restrict fracking in only the most sensitive areas.

The U.S. EPA and a few states, primarily those without past history of large scale gas production, are examining hydraulic fracturing ("fracking") practices and considering new regulations designed to ensure safe operations. Improvements to fracking technology and its combined use with horizontal drilling helped drive down the cost of shale gas production and turn it into an economic resource. Fracking involves drilling a well and propagating fractures in the shale source rock by injecting large amounts of fluid. The fluid is primarily water mixed with sand and a small amount of chemicals. While most fracking operations have been performed without incident, some fear that accidental leakage of waste water or uncontrolled fracturing might contaminate groundwater aquifers. Potential regulations might drive up the cost of hydrofracking or restrict areas for drilling.

Although tighter regulations might impose additional cost to shale gas development, it is unlikely that they would kill shale gas growth. The fracking process includes installing multiple layers of cement and casing to protect against leakage into groundwater and subsurface. Furthermore, groundwater aquifers are typically located at much shallower depths than the production zone.

When employing best practices, hydrofracking operations have demonstrated to be safe and reliable. More stringent regulations will most likely enforce adoption of best practices in hydrofracking operations. As such, they would not be expected to impose significant added cost to those already employing best practices. If a ban on fracking is imposed, it is likely to be restricted to highly sensitive areas, such as near sources of drinking water or population centers. For example, New York's Department of Environmental Conservation recently lifted a fracking ban on all but the most sensitive areas, leaving 85% of the state's Marcellus Shale open to drilling.[4]

Furthermore, fracking regulations may likely be imposed at a state level. Some major shale gas producing states, including Texas and Louisiana, have a long history of oil and gas production and may be unlikely to impose new regulations on hydrofracking. These states have experienced an economic boom due to rapid growth in shale gas production in the Barnett, Haynesville, and Eagle Ford basins located in their states and are unlikely to restrict future prospects with additional regulations. Therefore, most shale gas operations are unlikely to be greatly affected by new fracking regulations.

[4] http://money.cnn.com/2011/07/01/news/economy/fracking_new_york/index.htm

Finally, additional costs imposed by new fracking regulations will be partly borne by producers and partly passed on to consumers in the form of higher prices. Shale gas is a vital resource, and prices will reflect a level necessary to support their production. Therefore, new fracking regulations are unlikely to drive up costs to the point of making shale gas uneconomic to produce.

Concern: Exporting gas will result in a significant increase in the price of gas for U.S. industry, causing them to be uncompetitive in global markets, leading to a loss of jobs.

DMP Analysis: The modest price impact from proposed export volumes is unlikely to cause the U.S. to be uncompetitive in global markets.

The WGM results indicate that U.S. prices will not significantly increase due to LNG export. The projected change in the average U.S. price is a rather modest $0.12/MMBtu, a 1.7% increase over the Reference Case without LNG exports. The projected impact is greatest near the export terminals but dissipates with distance away from the Gulf region. The price impact is less than $0.10/MMBtu in most downstream markets. Given the projected price impact, it is highly unlikely that it would cause U.S. industry to be uncompetitive in global markets and lead to a loss of jobs. The U.S. has lower gas prices than most industrialized countries and is projected to continue to have lower gas prices, in part due to continued growth in shale gas production. An increase in gas price of less than 2% is unlikely to change the U.S. competitiveness in global markets.

Furthermore, even with exports, U.S. prices will be lower than those in the importing countries. Otherwise, export would be uneconomic. The high cost of constructing a liquefaction plant plus the high transportation cost of a LNG tanker is estimated to require a spread of at least $3.00/MMBtu to Europe and over $4.00/MMBtu to Asia in order to make LNG export economic to those regions. Exporting LNG from the U.S. is being considered now because the price spreads from the U.S. Gulf to Europe and Asia are well above those levels. However, the key point is that even with LNG exports, the U.S. has a built-in cost advantage for natural gas because of the cost differential to get LNG to European and Asian markets. LNG exports alone cannot elevate U.S. prices to European and Asian price levels because of the cost differential.

To illustrate this point, consider the Gulf to the Mid-Atlantic regions which are connected by major pipelines. However, Mid-Atlantic prices are still substantially higher than Gulf prices because of the transportation costs. At specific market hubs, such as New York City, prices can skyrocket during extreme peak demand days because of deliverability constraints on the pipeline system. Even though markets are connected, deliverability constraints can and will decouple their prices during peak periods. The total European gas demand is nearly as large as the U.S. demand. The LNG export volume being considered represents a small fraction of European demand, as well as U.S. supply. The proposed LNG export volumes are inadequate to bring these markets to parity because of transportation costs and capacity constraints.

Concern: Exporting gas will result in a significant increase in the price of electricity for U.S. consumers and industry, causing them to be uncompetitive in global markets, leading to a loss of jobs.

DMP Analysis: The projected impact on electricity prices is projected to be even smaller than the projected impact on gas prices.

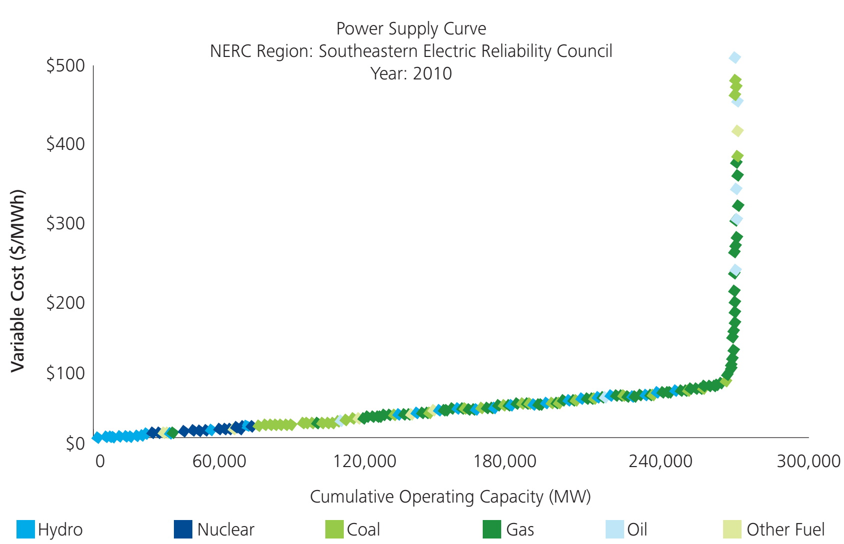
DMP's electricity model is integrated with the WGM so we can also estimate the impact of LNG exports on electricity prices, as natural gas is also a fuel for generating electricity. Since our integrated models represent the geographic linkages between the electricity and natural gas systems, we can compute the impact of the LNG exports in local markets where the impact would be the greatest.

Comparison of electricity prices with and without LNG exports shows that projected electricity prices increase by 1.2% in Louisiana where most of the LNG exports are assumed to occur. The impact is far less than the projected 3.3% Louisiana gas price impact. In power markets in other regions, the impact is projected to be much less because the gas price impact is much less. For example, Midwest gas prices increase by less than 1.0% and result in electricity prices increasing by much less than 1.0%.

A key reason why the electricity price impact is less is that gas price will impact electricity price only if gas-fired generation is at the margin. When gas-fired generation is lower cost than the marginal source, then a small increase in gas price will only impact electricity price if it is sufficient to drive it to the margin. If it is higher cost than the marginal source, then increasing gas price will have no impact because it still would not be utilized. If gas-fired generation is the marginal source, then electricity prices will increase with gas price but only up to the point where some other source can displace it as the marginal source. Every power region has numerous competing generation plants burning different fuel types which will mitigate the price impact of increase in any one fuel.

Figure 11 shows the 2010 power supply curve for the SERC Reliability Corporation (SERC) region which includes Louisiana. The curve plots the variable cost of generation and capacity by fuel type. Depending on where the demand curve intersects the supply curve, a particular fuel type will set the electricity price. During extremely low demand periods, hydro, nuclear, or coal plants will likely set the price. An increase in gas price during these periods would not impact electricity price in this region because gas-fired plants are typically not utilized during these periods. During moderate or moderately high demand periods, coal or gas could be the marginal fuel type. If it is gas on the margin, price can rise only up to the cost of the next marginal fuel type (e.g., coal plant). If gas remains on margin, then the following calculation demonstrates the expected electricity price impact. At the projected gas price impact of \$0.22/MMBtu, a typical gas plant with a heat rate of 7,500 would cost an additional \$1.65/MWh (=\$0.22/MMBtu x 7500 Btu/MWh x 1 MMBtu/1000 Btu). Remember, that is the most that the gas price increase could elevate electricity price. Power load fluctuates greatly during a day, typically peaking during midafternoon and falling during the night. That implies that the marginal fuel type will also vary and gas will be at the margin only part of the time.

Figure 11: Power supply curve for SERC region



Concern: LNG exports will cause U.S. gas prices to trade at global price levels.

DMP Analysis: The volume of LNG exports, as well as the high cost of LNG exports, is inadequate to cause U.S. prices to trade at global price levels.

Based on our analysis, it is unlikely that a limited amount of LNG exports would cause U.S. gas price to be set at global price levels. For one thing, there is no world gas price, in contrast to the oil market in which there is a world oil price. Natural gas, unlike oil, is highly unlikely to ever have a world price. The cost of transportation, on a unitized energy basis, is much higher for gas than it is for oil. Therefore, global gas markets will remain partially interconnected regional markets with prices within each region determined by regional supply and demand balances.

Furthermore, even if there were a global gas market, having a fixed export capacity would not necessarily mean that domestic prices would rise to global price levels. For example, the current European prices (e.g., Zeebrugge, Belgium) are more than double the current Henry Hub price. Exporting 6 Bcfd to Europe would not mean that Henry Hub price would rise to the level of European prices minus the transportation costs differential. Limited transportation capacity would prevent prices from coupling. The same phenomena occur in the U.S. during peak winter days when there are often huge differences between Henry Hub and New York City prices. The basis differential between Henry and New York can rise to many times greater than the transportation cost between the regions. Transportation bottlenecks along the route from the Gulf to New York City prevent Henry prices from rising along with New York City prices and cause these basis blowouts.

As stated previously, even with exports, U.S. prices will be lower than those in the importing countries. Otherwise, export would be uneconomic. The high cost of constructing a liquefaction plant plus the high transportation cost of a LNG tanker would require a spread of at least $3.00/MMBtu to Europe and over $4.00/MMBtu to Asia in order to make LNG export economic to those regions. Exporting LNG from the U.S. is being considered now because the spreads to Europe and Asia are well above those levels. However, the key point is that even with LNG exports, the U.S. has a built-in cost advantage for natural gas. LNG exports alone cannot elevate U.S. prices to European and Asian price levels because of the cost differential.

Concern: Exporting gas will make U.S. prices more volatile as it will link them to global oil markets.
DMP Analysis: The relatively low volume of LNG exports is unlikely to cause significant change in U.S. price volatility.

Whether exports will increase U.S. price volatility involves close examination of seasonal, deliverability, supply contracts, and storage operations. Europe, which along with Asia are expected to be the primary targets for LNG exports, has a highly seasonal demand and little storage capacity relative to the U.S. which translates to highly seasonal prices.

We believe a better question to consider is whether U.S. prices could be pulled up by LNG exports to prices in global markets during peak periods. The price volatility in foreign markets might then be transmitted to U.S. prices.

An examination of historical prices reveals that European prices are no more volatile than U.S. prices. There is a misconception by some that European gas prices are more volatile because they are higher than U.S. prices. This is not true. In fact, during most of the past 20 years, the U.S. had the most volatile prices of all major gas consuming countries.[5] One reason for this is because European countries have long-term supply contracts to meet most of their peak loads and their markets are far more regulated than the U.S. market. Japanese prices are the least volatile because most of their supplies are from long-term contracts that have price smoothing mechanisms (e.g., three-month rolling average price) designed to reduce sharp price swings. Furthermore, the Japanese gas demand is primarily for power generation, which is not highly seasonal.

[5] Natural Gas Price Volatility: Lessons from Other Markets; Report for the American Clean Skies Foundation. Austin F. Whitman, M.J. Bradley & Associates LLC, 2011.

Nevertheless, could connecting to other countries increase the price volatility in the U.S.? For many of the same reasons described in the previous sections, limited LNG exports are unlikely to cause U.S. prices to be more volatile. The volume of exports is relatively small compared to the entire size of the U.S. supply and small relative to the entire European market. If demand increased with a concomitant increase in supply, price and volatility could increase. However, LNG exports will be anticipated by producers and supplies will be made available when they are needed. In fact, prospective LNG exporters are already lining up potential gas suppliers to provide gas for liquefaction.

The concern that LNG exports will increase volatility may be based on observations of price spikes when demand surges during peak days. Temporal supply demand balance can cause short-term price volatility. When the balance is tight, prices tend to rise, and when the balance is slack, prices tend to fall. However, it is an entirely different matter to say that well-anticipated demand growth will cause a tighter market that is more prone to price run-ups during peak periods. Short-term price volatility arises from short-term inelasticities in supply and demand. For example, when demand spikes suddenly, more gas supplies cannot immediately be produced. Productive capacity is fairly fixed in the short term. There is a long lead time before reserves can be added and produced. However, when new demand is well anticipated, productive capacity will rise to meet it.

Hence, the absolute level of demand has little bearing on price volatility. As an example, consider the price volatility of this year, when U.S. demand is trending towards a historical high, compared to the volatility in 2008, when demand was lower. Price volatility this year has been far lower than in 2008 which saw huge gyrations in price. This demonstrates that gas price volatility is not a simple function of absolute gas demand level because gas productive capacity will be developed to match the anticipated demand level.

Some point to the volatility in world oil prices, which translates to volatility in domestic oil and gasoline prices, as a reason for not exporting LNG. However, this is a poor comparison. The cost of transportation, on a unitized energy basis, is much higher for gas than it is for oil. Therefore, global gas markets will remain partially interconnected regional markets with prices within each region determined by regional supply and demand balances.

It is possible that LNG exports might actually work to decrease, not increase, U.S. price volatility. This is counterintuitive but quite possible because LNG exports, with their well-known export capacities, will prompt incremental supplies that could be utilized to meet peak domestic demand. During peak periods when domestic prices shoot up, it might be more advantageous for LNG exporters to not export but rather keep the supplies in the U.S.

Finally, arguments against LNG exports purely on the grounds of increased prices or volatility could just as well be made against any type of domestic demand. After all, a given volume of demand increase, whether it is for domestic consumption or export, will have the same impact on price.

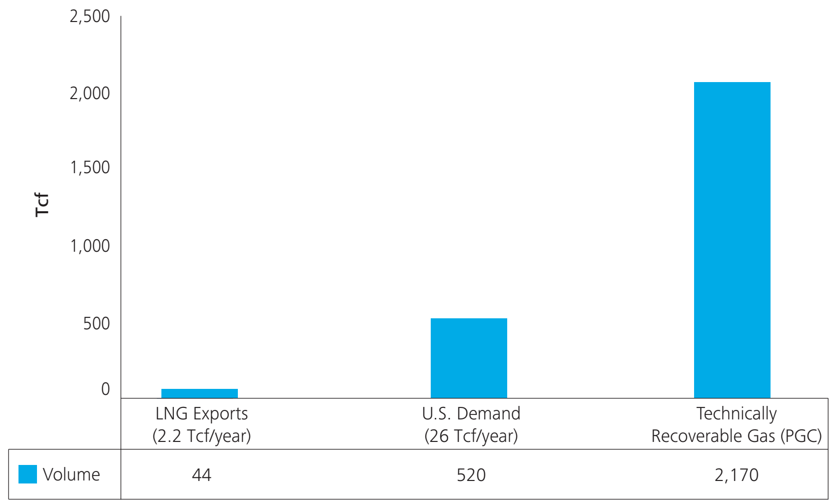
Concern: Exporting gas decreases U.S. energy security.
DMP Analysis: The assumed volume of exports is insignificant compared to total U.S. resource potential.

The energy security issue is based on the fear that exporting LNG will deplete domestic resources, leaving the U.S. dependent on foreign suppliers in the future and vulnerable to price manipulation or supply curtailment. However, the incremental 2.2 Tcf (6 Bcf/day x 365 days/year) of LNG annual exports are fairly insignificant compared to over 2,170 Tcf of technically recoverable gas in the U.S. as estimated by the Potential Gas Committee.[6] (The EIA's latest estimate is even higher: 2,587 Tcf of technically recoverable gas in the U.S.)

Figure 12 illustrates the relative magnitudes of LNG export volumes and U.S. demand for a 20-year period compared to the technically recoverable gas resources in the U.S. This comparison demonstrates that export volumes pale in comparison to both total demand and total domestic supply.

Of course, this simple calculation does not tell the whole story because it ignores the impact on supply cost. However, it underscores the point that economics, not security, is the concern. The volume of LNG exports and projected price impact based on the various assumptions in the WGM are inadequate to pose a security issue. Unless the U.S. is able to convert oil usage to natural gas (i.e., automobiles) to reduce dependence on foreign oil, the issue becomes more one of economics rather than one of energy security.

Figure 12: Comparison of volumes



[6] Potential Gas Committee press release, April 27, 2011.

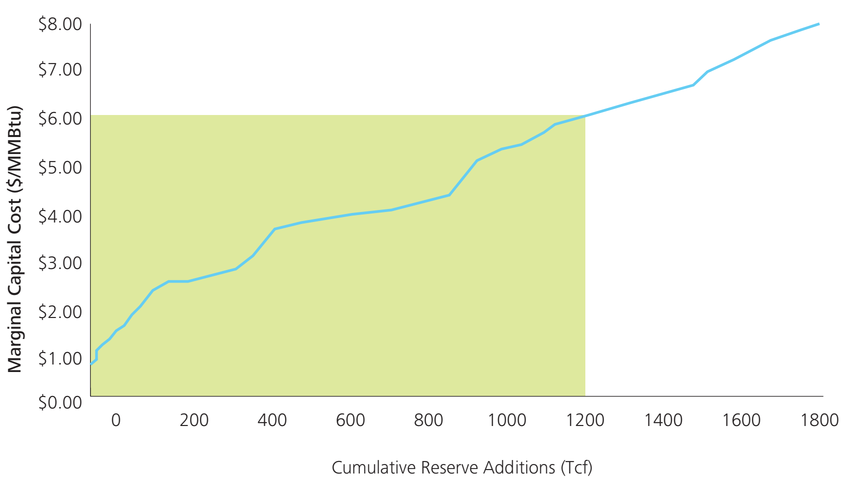
Concern: There are insufficient reserves to allow exports to continue without impacting the market over the term of those exports.

DMP Analysis: The projected volume of LNG exports is insignificant compared to total U.S. resource potential.

As we described in previous sections, the impact of LNG exports would be fairly small to domestic gas markets and almost imperceptible to the power market. The domestic gas resource base, represented by the supply curve in Figure 13, is estimated to be adequate to supply projected demand levels for at least 50 years at moderate prices. The volume of LNG exports represents a relatively small increment to the total demand.

Furthermore, technological advancements will likely continue to drive down production costs, thereby reducing the high cost end of the supply curve. Some of the largest energy supermajors have committed to shale gas development and improving technologies and procedures to drive down their costs. This implies more economically recoverable gas and a prolonged period of relatively low gas prices with or without LNG exports.

Figure 13. U.S. supply curve



It is important to note that the volume of "reserves" is not the issue but rather the volume of "resources." Reserves are volumes of resource that have been "proved up" and ready for production. Resources, on the other hand, are the total volumes that are in the ground, most of which have yet to be proved up or even discovered, but can be reasonably estimated based on geological and other factors.

Concern: LNG exports are inconsistent with the U.S. policy of energy independence.

DMP Analysis: Large domestic gas supplies will maintain natural gas independence even with exports.

There is a frequently expressed desire for energy independence in the U.S., but there is no official U.S. policy for energy independence. The U.S. is largely independent of non-North American natural gas supplies. The energy dependency that the general public has in mind usually relates to oil imports and the resulting export of dollars to the oil-exporting countries. Perhaps the thought is that gas can displace the oil imports and help alleviate U.S. dependence on foreign oil. If this is the goal, then it would require retrofit of millions of vehicles and thousands of refueling stations. This has been much discussed but never done because of the tremendous costs involved. Due to the high density of oil, it is a near perfect fuel for transportation. Natural gas, although much cheaper and domestically available, lacks the desired properties of oil and therefore is unlikely to capture a significant share of the transportation market.

Furthermore, natural gas is not a substitute for oil to a significant degree in any other sector. There are very few oil-fired power plants, and those generally have low utilization rates. Very few industrial boilers burn oil because of its high cost and emissions. Indeed there is very limited oil-gas substitutable demand. Therefore, at present, there is little that natural gas can do to alleviate the country's dependence on oil imports.

Finally, energy exports from the U.S. are not without precedent. The U.S. has been exporting coal for years, as well as exporting LNG from Alaska. The U.S. also exports gas to Mexico. The attention on LNG exports on security grounds seems inconsistent with these other examples.

Concern: Exporting gas will reduce U.S. ability to maximize use of gas domestically.

DMP Analysis: There are sufficient volumes of domestic natural gas for both domestic consumption and LNG exports.

As we discussed earlier, there are sufficient volumes for both domestic use and exports. As stated previously, the domestic gas resource base is estimated to be adequate to supply projected demand levels for at least 50 years at moderate prices. The volume of LNG exports represents a relatively small increment to the total demand. This concern would be more relevant if the U.S. did not possess the abundant shale gas resources that it does, but then again, there would be no talk about LNG exports if that was the case.

One could argue that allowing export of LNG is making maximal use of domestic gas because producers are finding a market for gas that would otherwise not be produced.

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Deloitte MarketPoint is a decision support solutions company focused on fundamental market analysis and price forecasting. We provide software and models with consulting services to help energy companies make informed decisions. Our solutions are comprised of our software applications, such as MarketBuilder, our models, our market data, and consulting services. Certain services may not be available to attest clients under the rules and regulations of public accounting.

Deloitte MarketPoint LLC, the result of Deloitte's acquisition of substantially all the assets of MarketPoint Incorporated and Altos Management Partners (MarketPoint/Altos) in 2011, combines the global strength and quantitative experience of Deloitte and the member firm network of Deloitte Touche Tohmatsu Limited with the market-leading software and time-tested energy market success of MarketPoint/Altos. Deloitte MarketPoint is located within the Deloitte Center for Energy Solutions.

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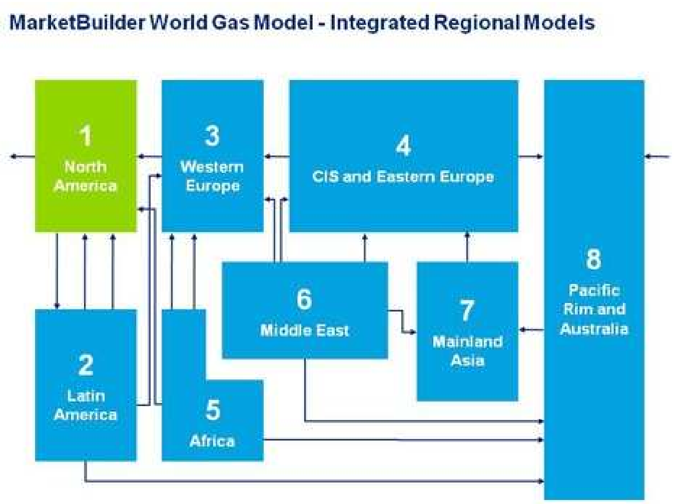
Natural Gas Models

North American Gas Model

The North American Gas Model is designed to simulate how regional interactions of supply, transportation, and demand determine market clearing prices, flowing volumes, storage, reserve additions, and new pipelines throughout the North American natural gas market.

Deloitte MarketPoint's North American Gas Model is differentiated by its ability to forecast market clearing prices and basis differentials among producing and consuming regions and thereby contributes to the valuation of a wide range of gas assets. It is based on the North American Regional Gas Model (NARG) that has been used for many of the pipeline expansion decisions and resource basin profitability evaluations in North America since 1983. It is the grandson of the NARG model used in the landmark National Petroleum Council 2003 study on natural gas, updated and improved initially by MarketPoint, Inc. and its sibling company, Altos Management Partners (together, MarketPoint/Altos), until they were acquired by Deloitte Investments, LLC in 2010, and now by Deloitte MarketPoint to meet current market conditions.



Accompanying the North American Gas Model is a proprietary database that enumerates and quantifies all gas plays (as assessed by the National Petroleum Council) in North America. This database contains field size and depth distributions for every play, with a finding and development cost model included. This database connects these gas plays with other energy products such as coal, power, and emissions. It also includes factors to model the growth of synfuels, LNG imports, and oil-for-gas substitution. Finally, it contains over 300 demand nodes representing regional demands from residential, commercial, industrial, electric generation, and transportation consumers.

Deloitte MarketPoint offers both short- and long-term versions of the North American Gas Model (Gas Model). The long-term version covers 40 years based on fundamental economic factors. The short-term model expands the long-term model by embedding a dynamic behavioral model of natural gas storage. Because of this, the Deloitte MarketPoint short-term Gas Model is a better choice for predicting shorter term price variations than linear programming models. The end result is that valuing storage investments, identifying maximally effectual storage field operation, positioning, optimizing cycle times, demand following modeling, pipeline sizing and location, and analyzing the impacts of LNG has become easier and generally more accurate.

World Gas Model

The World Gas Model extends the North American Gas model to account for the globalization of the gas industry by LNG technology. The World Gas Model is an integrated model of world supply, transportation, shipping, liquefaction, regasification, infrastructure, and demand. It is based on the MarketPoint/Altos World Gas Trade Model (WGTM) extension to the NARG model, which resulted from the multi-client program begun in 1990 by the consulting company that predated MarketPoint/Altos. This model was able to help the initial subscribers meet their requirements for price forecasting and fundamental analysis as well as the subsequent adopters in later years.

The World Gas Model simulates local and regional interactions among resource supply, field processing, outbound pipelining, liquefaction, shipping, regasification, distribution, demand, and interfuel competition. The World Gas Model subdivides the world into major regions connected by actual and proposed marine shipping routes and pipelines. Competition with oil and coal is modeled in each consuming region, producing results that indicate what infrastructure is most likely to be constructed in the future. Markets for emission credits and their potential impact on energy markets are included.

The World Gas Model contains:

- 821 regions and sub-regions worldwide
- 708 demand nodes worldwide
- 7,566 full forward price schedules worldwide, including wellhead, field processing, pipeline initiation, pipeline hub, wholesale, citygate, residential, commercial, industrial, and power generation wholesale prices
- 22 liquefaction regions worldwide, each with a full schedule of new and existing liquefaction plants
- 34 regasification regions worldwide, each with a full schedule of new and existing regasification facilities
- 748 existing and prospective LNG shipping routes
- 1,910 transportation links including pipeline routes and LNG routes
- A total of 5,538 nodes worldwide

Regional Components of the World Gas Model

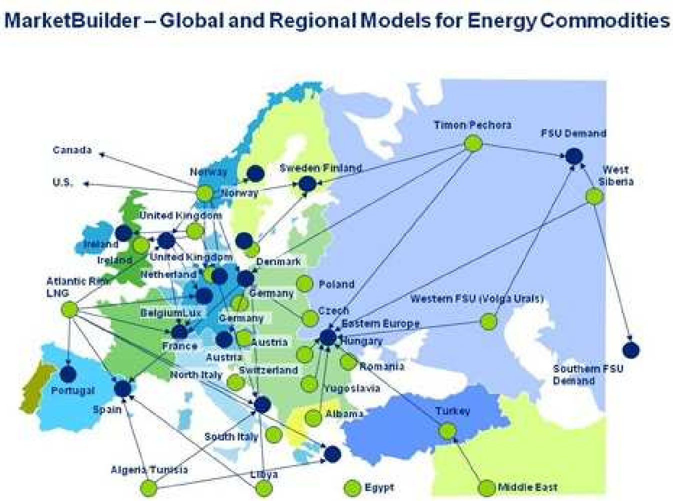
The following models exemplify extensive work done on the regional component models of the MarketPoint World Gas Model.

South American Model

Regional gas pipelines can also be analyzed by MarketBuilder. For example, the gas business in South America (the Southern Cone) has been partially deregulated and privatized. The profitability of this business depends highly on the ability to accurately predict forward prices at both the basins and upstream ends of the pipelines. The Southern American Model addresses that need by creating a customized model of the South American Natural Gas market.

Predicting forward prices requires considering a variety of factors, such as significant gas growth, competing fuels, and the ability of asset owners to monetize and capture profits. Each of these factors requires its own model. For example, demand growth depends on a wide variety of factors, such as the price of gas, underlying economic growth, politics, project costs, transit fees, and resource availability.

European Gas Model



Europe, with its 350 million people, large and growing industrial base, and increasing environmental concern, has become a popular place to invest in natural gas infrastructure. As with most investment decisions -- there will be winners and losers. The European Gas Model was designed to help companies understand the investment risks and assist companies in making informed investing decisions.

Secretary of Energy Advisory Board

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Shale Gas Production Subcommittee Second Ninety Day Report

November 18, 2011

U.S. DEPARTMENT OF ENERGY

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

Executive Summary

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

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

The Second Ninety-Day Report

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 2. Recommendations requiring cooperation between regulators and industry

<table>
<tr><th>Rec.#</th><th>Recommendation</th><th>Comment & Status</th></tr>
<tr><td>8</td><td>Measure and publicly report the composition of water stocks and flow throughout the fracturing and cleanup process.</td><td rowspan="2">Awaits EPA’s study underway on the Impacts of hydraulic fracturing on drinking water resources. See discussion below. States should also determine a way forward to measure and record data from flow back operations as many issues will be local issues.</td></tr>
<tr><td>9</td><td>Manifest all transfers of water among different locations</td></tr>
<tr><td>10</td><td>Adopt best practices in well development and construction, especially casing, cementing, and pressure management</td><td>Widely recognized as a key practice by companies and regulators but no indication of a special initiative on field measurement and reporting.</td></tr>
<tr><td>12</td><td>Adopt requirements for background water quality measurements</td><td>The value of background measurements is recognized. Jurisdiction for access to private wells differs widely</td></tr>
</table>

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

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

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

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

Table 3. Recommendations that require new mechanisms for success

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

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

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

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

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

Concluding remarks

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

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

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

ANNEX A – CHARGE TO THE SUBCOMMITTEE

From: Secretary Chu

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

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

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

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

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

Membership:

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

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

Consultation with other Agencies:

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

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

Public input:

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

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

Scope of work of the Subcommittee:

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

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

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

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

Delivery of Recommendations and Advice:

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

Other:

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

ANNEX B – MEMBERS OF THE SUBCOMMITTEE

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

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

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

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

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

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

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

Annex C – Subcommittee Recommendations

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

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

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

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

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

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

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

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

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

    9. Manifest all transfers of water among different locations.

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

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

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

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

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

14. <u>Disclosure of fracturing fluid composition</u>: The Subcommittee shares the prevailing view that the risk of fracturing fluid leakage into drinking water sources through fractures made in deep shale reservoirs is remote.[7] Nevertheless the Subcommittee believes there is no economic or technical reason to prevent public disclosure of all chemicals in fracturing fluids, with an exception for genuinely proprietary information. While companies and regulators are moving in this direction, progress needs to be accelerated in light of public concern.

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

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

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

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

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

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

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

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

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

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

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

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

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

Annex D Letter from the Office of Management and Budget

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

THE DIRECTOR

November 8, 2011

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

Dear John:

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

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

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

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

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

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

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

Best regards,

Jacob J. Lew

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

John Deutch Institute Professor
Department of Chemistry
Tel: 617 253 1479
Fax: 617 258 6700
Email: jmd@mit.edu

To: Jack Lew, Director Office of Management and Budget

Dear Jack, November 1, 2011

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

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

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

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

Sincerely

John Deutch

John Deutch

Cc: Steven Chu,
Heather Zichal,
Michael Froman

ENDNOTES

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

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

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

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

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

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

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

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

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

[7] An interesting Society of Petroleum Engineers paper sheds light on this point: *Hydraulic Fracture-Height Growth: Real Data,* Kevin Fisher and Norm Warpinski, SPE 145949 available at:
http://www.spe.org/atce/2011/pages/schedule/tech_program/documents/spe145949%201.pdf .

Secretary of Energy Advisory Board

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Shale Gas Production Subcommittee 90-Day Report

August 18, 2011

U.S. DEPARTMENT OF ENERGY

The SEAB Shale Gas Production Subcommittee
Ninety-Day Report – August 18, 2011

Executive Summary

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board is charged with identifying measures that can be taken to reduce the environmental impact and improve the safety of shale gas production.

Natural gas is a cornerstone of the U.S. economy, providing a quarter of the country's total energy. Owing to breakthroughs in technology, production from shale formations has gone from a negligible amount just a few years ago to being almost 30 percent of total U.S. natural gas production. This has brought lower prices, domestic jobs, and the prospect of enhanced national security due to the potential of substantial production growth. But the growth has also brought questions about whether both current and future production can be done in an environmentally sound fashion that meets the needs of public trust.

This 90-day report presents recommendations that if implemented will reduce the environmental impacts from shale gas production. The Subcommittee stresses the importance of a process of continuous improvement in the various aspects of shale gas production that relies on best practices and is tied to measurement and disclosure. While many companies are following such a process, much-broader and more extensive adoption is warranted. The approach benefits all parties in shale gas production: regulators will have more complete and accurate information; industry will achieve more efficient operations; and the public will see continuous, measurable improvement in shale gas activities.

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

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

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

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

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

  (2) Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of shale gas operations through out the lifecycle of natural gas use in comparison to other fuels; and

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

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

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

  (2) Manifest all transfers of water among different locations.

  (3) Adopt best practices in well development and construction, especially casing, cementing, and pressure management. Pressure testing of cemented casing and state-of-the-art cement bond logs should be used to confirm formation isolation. Microseismic surveys should be carried out to assure that hydraulic fracture growth is limited to the gas producing formations. Regulations and inspections are needed to confirm that operators

have taken prompt action to repair defective cementing jobs. The regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing.

(4) Additional field studies on possible methane leakage from shale gas wells to water reservoirs.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The Subcommittee believes that these recommendations, combined with a continuing focus on and clear commitment to measurable progress in implementation of best practices based on technical innovation and field experience, represent important steps toward meeting public concerns and ensuring that the nation's resources are responsibly being responsibly developed.

Introduction

On March 31, 2011, President Barack Obama declared that "recent innovations have given us the opportunity to tap large reserves – perhaps a century's worth" of shale gas. In order to facilitate this development, ensure environmental protection, and meet public concerns, he instructed Secretary of Energy Steven Chu to form a subcommittee of the Secretary of Energy Advisory Board (SEAB) to make recommendations to address the safety and environmental performance of shale gas production.[1] The Secretary's charge to the Subcommittee, included in Annex A, requested that:

> Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracturing.

This is the 90-day report submitted by the Subcommittee to SEAB in fulfillment of its charge. There will be a second report of the Subcommittee after 180 days. Members of the Subcommittee are given in Annex B.

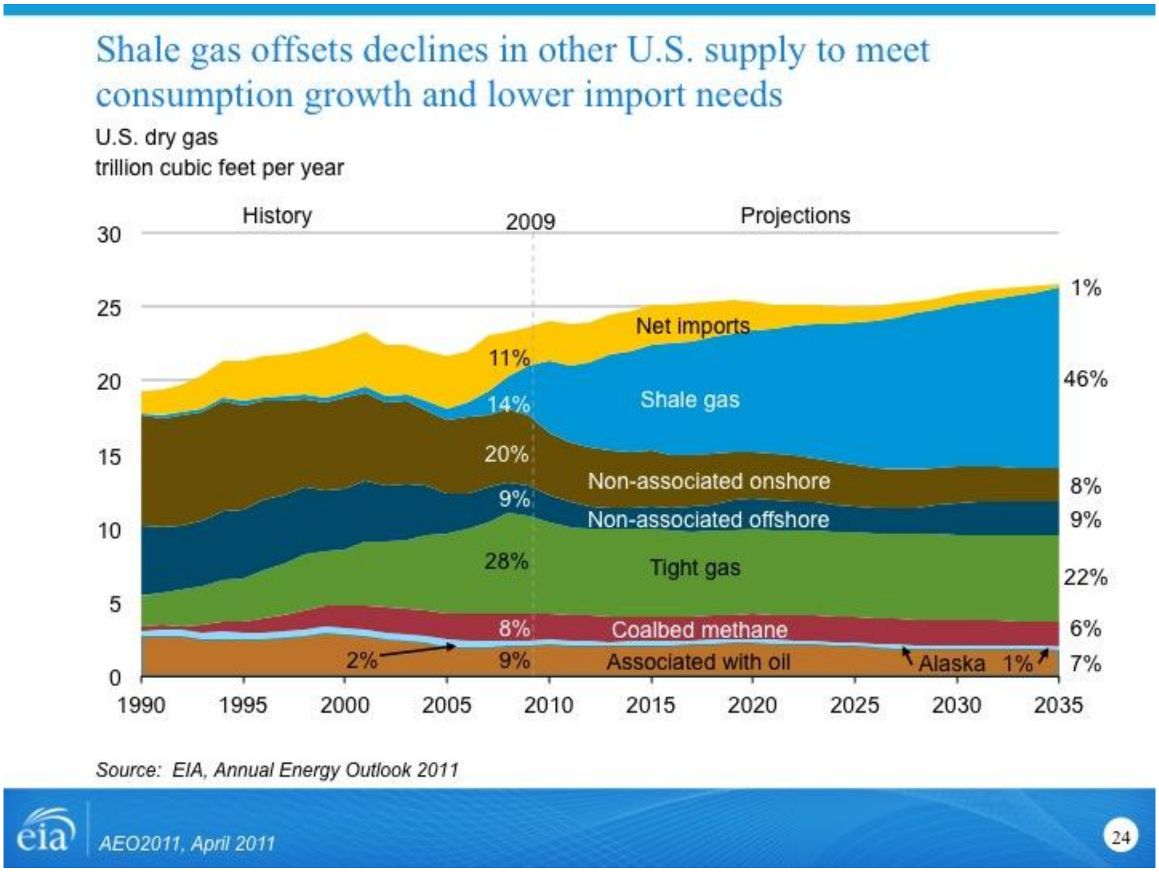
Context for the Subcommittee's deliberations

The Subcommittee believes that the U.S. shale gas resource has enormous potential to provide economic and environmental benefits for the county. Shale gas is a widely distributed resource in North America that can be relatively cheaply produced, creating jobs across the country. Natural gas – if properly produced and transported – also offers climate change advantages because of its low carbon content compared to coal.

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Domestic production of shale gas also has the potential over time to reduce dependence on imported oil for the United States. International shale gas production will increase the diversity of supply for other nations. Both these developments offer important national security benefits.[2]

The development of shale gas in the United States has been very rapid. Natural gas from all sources is one of America's major fuels, providing about 25 percent of total U.S. energy. Shale gas, in turn, was less than two percent of total U.S. natural gas production in 2001. Today, it is approaching 30 percent.[3] But it was only around 2008 that the significance of shale gas began to be widely recognized. Since then, output has increased four-fold. It has brought new regions into the supply mix. Output from the Haynesville shale, mostly in Louisiana, for example, was negligible in 2008; today, the Haynesville shale alone produces eight percent of total U.S. natural gas output. According to the U.S. Energy Information Administration (EIA), the rapid expansion of shale gas production is expected to continue in the future. The EIA projects shale gas to be 46 percent of domestic production by 2035. The following figure shows the stunning change.



The economic significance is potentially very large. While estimates vary, well over 200,000 of jobs (direct, indirect, and induced) have been created over the last several years by the development of domestic production of shale gas, and tens of thousands more will be created in the future.[4] As late as 2007, before the impact of the shale gas revolution, it was assumed that the United States would be importing large amounts of liquefied natural gas from the Middle East and other areas. Today, the United States is essentially self-sufficient in natural gas, with the only notable imports being from Canada, and expected to remain so for many decades. The price of natural gas has fallen by more than a factor of two since 2008, benefiting consumers in the lower cost of home heating and electricity.

The rapid expansion of production is rooted in change in applications of technology and field practice. It had long been recognized that substantial supplies of natural gas were embedded in shale rock. But it was only in 2002 and 2003 that the combination of two technologies working together – hydraulic fracturing and horizontal drilling – made shale gas commercial.

These factors have brought new regions into the supply mix. Parts of the country, such as regions of the Appalachian mountain states where the Marcellus Shale is located, which have not experienced significant oil and gas development for decades, are now undergoing significant development pressure. Pennsylvania, for example, which produced only one percent of total dry gas production in 2009, is one of the most active new areas of development. Even states with a history of oil and gas development, such as Wyoming and Colorado, have experienced significant development pressures in new areas of the state where unconventional gas is now technically and economically accessible due to changes in drilling and development technologies.

The urgency of addressing environmental consequences

As with all energy use, shale gas must be produced in a manner that prevents, minimizes and mitigates environmental damage and the risk of accidents and protects public health and safety. Public concern and debate about the production of shale gas has grown as shale gas output has expanded.

The Subcommittee identifies four major areas of concern: (1) Possible pollution of drinking water from methane and chemicals used in fracturing fluids; (2) Air pollution; (3) Community disruption during shale gas production; and (4) Cumulative adverse impacts that intensive shale production can have on communities and ecosystems.

There are serious environmental impacts underlying these concerns and these adverse environmental impacts need to be prevented, reduced and, where possible, eliminated as soon as possible. Absent effective control, public opposition will grow, thus putting continued production at risk. Moreover, with anticipated increase in U.S. hydraulically fractured wells, if effective environmental action is not taken today, the potential environmental consequences will grow to a point that the country will be faced a more serious problem. Effective action requires both strong regulation and a shale gas industry in which all participating companies are committed to continuous improvement.

The rapid expansion of production and rapid change in technology and field practice, requires federal and state agencies to adapt and evolve their regulations. Industry's pursuit of more efficient operations often has environmental as well as economic benefits, including waste minimization, greater gas recovery, less water usage, and a reduced operating footprint. So there are many reasons to be optimistic that continuous improvement of shale gas production in reducing existing and potential undesirable impacts can be a cooperative effort among the public, companies in the industry, and regulators.

Subcommittee scope, procedure and outline of this report

Scope: The Subcommittee has focused exclusively on production of natural gas (and some liquid hydrocarbons) from shale formations with hydraulic fracturing stimulation in either vertical or horizontal wells. The Subcommittee is aware that some of the observations and recommendations in this report could lead to extension of its findings to other oil and gas operations, but our intention is to focus singularly on issues related to shale gas development. We caution against applying our findings to other areas, because the Subcommittee has not considered the different development practices and other types of geology, technology, regulation and industry practice.

These shale plays in different basins have different geological characteristics and occur in areas with very different water resources. In the Eagle Ford, in Texas, there is almost no flow-back water from an operating well following hydraulic fracturing, while in the Marcellus, primarily in Ohio, New York, Pennsylvania and West Virginia, the flow-back water is between 20 and 40 percent of the injected volume. This geological diversity means that engineering practice and regulatory oversight will differ widely among regions of the country.

The Subcommittee describes in this report a comprehensive and collaborative approach to managing risk in shale gas production. The Subcommittee believes that a more systematic commitment to a process of *continuous improvement* to identify and implement best practices is needed, and should be embraced by all companies in the shale gas industry. Many companies already demonstrate their commitment to the kind of process we describe here, but the public should be confident that this is the practice across the industry.

This process should involve discussions and other collaborative efforts among companies involved in shale gas production (including service companies), state and federal regulators, and affected communities and public interests groups. The process should identify best practices that evolve as operational experience increases, knowledge of environmental effects and effective mitigation grows, and know-how and technology changes. It should also be supported by technology peer reviews that report on individual companies' performance and should be seen as a compliment to, not a substitute for, strong regulation and effective enforcement. There will be three benefits:

- For industry: As all firms move to adopt identified best practices, continuous improvement has the potential to both enhance production efficiency and reduce environmental impacts over time.
- For regulators: Sharing data and best practices will better inform regulators and help them craft policies and regulations that will lead to sounder and more efficient environmental practices than are now in place.
- For the public: Continuous improvement coupled with rigorous regulatory oversight can provide confidence that processes are in place that will result in improved safety and less environmental and community impact.

The realities of regional diversity of shale gas resources and rapid change in production practices and technology mean that a single best engineering practice cannot set for all locations and for all time. Rather, the appropriate starting point is to understand what are regarded as "best practices" today, how the current regulatory system works in the context of those operating in different parts of the country, and establishing a culture of continuous improvement.

The Subcommittee has considered the safety and environmental impact of all steps in shale gas production, not just hydraulic fracturing.[5] Shale gas production consists of several steps, from well design and surface preparation, to drilling and cementing steel casing at multiple stages of well construction, to well completion. The various steps include perforation, water and fracturing fluid preparation, multistage hydraulic fracturing, collection and handling of flow-back and produced water, gas collection, processing and pipeline transmission, and site remediation.[6] Each of these activities has safety and environmental risks that are addressed by operators and by regulators in different ways according to location. In light of these processes, the Subcommittee interprets its charge to assess this entire system, rather than just hydraulic fracturing.

<u>The Subcommittee's charge is not to assess the balance of the benefits of shale gas use against these environmental costs</u>. Rather, the Subcommittee's charge is to identify steps that can be taken to reduce the environmental and safety risks associated with shale gas development and, importantly, give the public concrete reason to believe that environmental impacts will be reduced and well managed on an ongoing basis, and that problems will be mitigated and rapidly corrected, if and when they occur.

<u>It is not within the scope of the Subcommittee's 90-day report to make recommendations about the proper regulatory roles for state and federal governments</u>. However, the Subcommittee emphasizes that effective and capable regulation is essential to protect the public interest. The challenges of protecting human health and the environment in light of the anticipated rapid expansion of shale gas production require the joint efforts of state and federal regulators. This means that resources dedicated to oversight of the industry must be sufficient to do the job and that there is adequate regulatory staff at the state and federal level with the technical expertise to issue, inspect, and enforce regulations. Fees, royalty payments and severance taxes are appropriate sources of funds to finance these needed regulatory activities.

The nation has important work to do in strengthening the design of a regulatory system that sets the policy and technical foundation to provide for continuous improvement in the protection of human health and the environment. While many states and several federal agencies regulate aspects of these operations, the efficacy of the regulations is far from clear. Raw statistics about enforcement actions and compliance are not sufficient to draw conclusions about regulatory effectiveness. Informed conclusions about the state of shale gas operations require analysis of the vast amount of data that is publically available, but there are surprisingly few published studies of this publically available data. Benchmarking is needed for the efficacy of existing regulations and consideration of additional mechanisms for assuring compliance such as disclosure of company performance and enforcement history, and operator certification of performance subject to stringent fines, if violated.

Subcommittee Procedure: In the ninety days since its first meeting, the Subcommittee met with representatives of industry, the environmental community, state regulators, officials of the Environmental Protection Agency, the Department of Energy, the Department of the Interior, both the United States Geologic Survey (USGS) and the Bureau of Land Management (BLM), which has responsibility for public land regulation,[7] and a number of individuals from industry and not-for-profit groups with relevant expertise and interest. The Subcommittee held a public meeting attended by over four hundred citizens in Washington Country, PA, and visited several Marcellus shale gas sites. The Subcommittee strove to hold all of its meeting in public although the Subcommittee held several private working sessions to review what it had learned and to deliberate on its course of action. A website is available that contains the Subcommittee meeting agendas, material presented to the Subcommittee, and numerous public comments.[8]

Outline of this report: The Subcommittee findings and recommendations are organized in four sections:

- Making information about shale gas production operations more accessible to the public – an immediate action.
- Immediate and longer term actions to reduce environmental and safety risks of shale gas operations
- Creation of a Shale Gas Industry Operation organization, on national and/or regional basis, committed to continuous improvement of best operating practices.
- R&D needs to improve safety and environmental performance – immediate and long term opportunities for government and industry.

The common thread in all these recommendations is that measurement and disclosure are fundamental elements of good practice and policy for all parties. Data enables companies to identify changes that improve efficiency and environmental performance and to benchmark against the performance of different companies. Disclosure of data permits regulators to identify cost/effective regulatory measures that better protect the environment and public safety, and disclosure gives the public a way to measure progress on reducing risks.

Making shale gas information available to the public

The Subcommittee has been struck by the enormous difference in perception about the consequences of shale gas activities. Advocates state that fracturing has been performed safety without significant incident for over 60 years, although modern shale gas fracturing of two mile long laterals has only been done for something less than a decade. Opponents point to failures and accidents and other environmental impacts, but these incidents are typically unrelated to hydraulic fracturing *per se* and sometimes lack supporting data about the relationship of shale gas development to incidence and consequences.[9] An industry response that hydraulic fracturing has been performed safely for decades rather than engaging the range of issues concerning the public will not succeed.

Some of this difference in perception can be attributed to communication issues. Many in the concerned public use the word “fracking” to describe all activities associated with shale gas development, rather than just the hydraulic fracturing process itself. Public concerns extend to accidents and failures associated with poor well construction and operation, surface spills, leaks at pits and impoundments, truck traffic, and the cumulative impacts of air pollution, land disturbance and community disruption.

The Subcommittee believes there is great merit to creating a national database to link as many sources of public information as possible with respect to shale gas development and production. Much information has been generated over the past ten years by state and federal regulatory agencies. Providing ways to link various databases and, where possible, assemble data in a comparable format, which are now in perhaps a hundred different locations, would permit easier access to data sets by interested parties.

Members of the public would be able to assess the current state of environmental protection and safety and inform the public of these trends. Regulatory bodies would be better able to assess and monitor the trends in enforcement activities. Industry would be able to analyze data on production trends and comparative performance in order to identify effective practices.

The Subcommittee recommends creation of this national database. A rough estimate for the initial cost is $20 million to structure and construct the linkages necessary for assembling this virtual database, and about $5 million annual cost to maintain it. This recommendation is not aimed at establishing new reporting requirements. Rather, it focuses on creating linkages among information and data that is currently collected and technically and legally capable of being made available to the public. What analysis of the data should be done is left entirely for users to decide.[10]

There are other important mechanisms for improving the availability and usefulness of shale gas information among various constituencies. The Subcommittee believes two such mechanisms to be exceptionally meritorious (and would be relatively inexpensive to expand).

The first is an existing organization known as STRONGER – the State Review of Oil and Natural Gas Environmental Regulation. STRONGER is a not-for-profit organization whose purpose is to accomplish genuine peer review of state regulatory activities. The peer reviews (conducted by a panel of state regulators, industry representatives, and environmental organization representatives with respect to the processes and policies of the state under review) are published publicly, and provide a means to share information about environmental protection strategies, techniques, regulations, and measures for program improvement. Too few states participate in STRONGER's voluntary review of state regulatory programs. The reviews allow for learning to be shared by states and the expansion of the STRONGER process should be encouraged. The Department of Energy, the Environmental Protection Agency, and the American Petroleum Institute have supported STRONGER over time.[11]

The second is the Ground Water Protection Council's project to extend and expand the *Risk Based Data Management System, which* allows states to exchange information about defined parameters of importance to hydraulic fracturing operations.[12]

The Subcommittee recommends that these two activities be funded at the level of $5 million per year beginning in FY2012. Encouraging these multi-stakeholder mechanisms will help provide greater information to the public, enhancing regulation and improving the efficiency of shale gas production. It will also provide support for STRONGER to expand its activities into other areas such as air quality, something that the Subcommittee encourages the states to do as part of the scope of STRONGER peer reviews.

Recommendations for immediate and longer term actions to reduce environmental and safety risks of shale gas operations

1. Improvement in air quality by reducing emissions of regulated pollutants and methane.

Shale gas production, including exploration, drilling, venting/flaring, equipment operation, gathering, accompanying vehicular traffic, results in the emission of ozone precursors (volatile organic compounds (VOCs), and nitrogen oxides), particulates from diesel exhaust, toxic air pollutants and greenhouse gases (GHG), such as methane.

As shale gas operations expand across the nation these air emissions have become an increasing matter of concern at the local, regional and national level. Significant air quality impacts from oil and gas operations in Wyoming, Colorado, Utah and Texas are well documented, and air quality issues are of increasing concern in the Marcellus region (in parts of Ohio, Pennsylvania, West Virginia and New York).[13]

The Environmental Protection Agency has the responsibility to regulate air emissions and in many cases delegate its authority to states. On July 28, 2011, EPA proposed amendments to its regulations for air emissions for oil and gas operations. If finalized and fully implemented, its proposal will reduce emissions of VOCs, air toxics and, collaterally, methane. EPA's proposal does not address many existing types of sources in the natural gas production sector, with the notable exception of hydraulically fractured well re-completions, at which "green" completions must be used. ("Green" completions use equipment that will capture methane and other air contaminants, avoiding its release.) EPA is under court order to take final action on these clean air measures in 2012. In addition, a number of states – notably, Wyoming and Colorado – have taken proactive steps to address air emissions from oil and gas activities.

The Subcommittee supports adoption of emission standards for both new and existing sources for methane, air toxics, ozone-forming pollutants, and other major airborne contaminants resulting from natural gas exploration, production, transportation and distribution activities. The Subcommittee also believes that companies should be required, as soon as practicable, to measure and disclose air pollution emissions, including greenhouse gases, air toxics, ozone precursors and other pollutants. Such disclosure should include direct measurements wherever feasible; include characterization of chemical composition of the natural gas measured; and be reported on a publically accessible website that allows for searching and aggregating by pollutant, company, production activity and geography.

Methane emissions from shale gas drilling, production, gas processing, transmission and storage are of particular concern because methane is a potent greenhouse gas: 25 to 72 times greater warming potential than carbon dioxide on 100-year and 20-year time scales respectively.[14] Currently, there is great uncertainty about the scale of methane emissions.

The Subcommittee recommends three actions to address the air emissions issue.

First, inadequate data are available about how much methane and other air pollutants are emitted by the consolidated production activities of a shale gas operator in a given area, with such activities encompassing drilling, fracturing, production, gathering, processing of gas and liquids, flaring, storage, and dispatch into the pipeline transmission and distribution network. Industry reporting of greenhouse gas emissions in 2012 pursuant to EPA's reporting rule will provide new insights, but will not eliminate key uncertainties about the actual amount and variability in emissions.

The Subcommittee recommends enlisting a subset of producers in different basins, on a voluntary basis, to immediately launch projects to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data.

These pioneering data sets will be useful to regulators and industry in setting benchmarks for air emissions from this category of oil and gas production, identifying cost-effective procedures and equipment changes that will reduce emissions; and guiding practical regulation and potentially avoid burdensome and contentious regulatory procedures. Each project should be conducted in a transparent manner and the results should be publicly disclosed.

There needs to be common definitions of the emissions and other parameters that should be measured and measurement techniques, so that comparison is possible between the data collected from the various projects. Provision should be made for an independent technical review of the methodology and results to establish their credibility. The Subcommittee will report progress on this proposal during its next phase.

The second recommendation regarding air emissions concerns the need for a thorough assessment of the greenhouse gas footprint for cradle-to-grave use of natural gas. This effort is important in light of the expectation that natural gas use will expand and substitute for other fuels. There have been relatively few analyses done of the question of the greenhouse gas footprint over the entire fuel-cycle of natural gas production, delivery and use, and little data are available that bear on the question. A recent peer-reviewed article reaches a pessimistic conclusion about the greenhouse gas footprint of shale gas production and use – a conclusion not widely accepted.[15] DOE's National Energy Technology Laboratory has given an alternative analysis.[16] Work has also been done for electric power, where natural gas is anticipated increasingly to substitute for coal generation, reaching a more favorable conclusion that natural gas results in about one-half the equivalent carbon dioxide emissions.[17]

The Subcommittee believes that additional work is needed to establish the extent of the footprint of the natural gas fuel cycle in comparison to other fuels used for electric power and transportation because it is an important factor that will be considered when formulating policies and regulations affecting shale gas development. These data will help answer key policy questions such as the time scale on which natural gas fuel switching strategies would produce real climate benefits through the full fuel cycle and the level of methane emission reductions that may be necessary to ensure such climate benefits are meaningful.

The greenhouse footprint of the natural gas fuel cycle can be either estimated indirectly by using surrogate measures or preferably by collecting actual data where it is practicable to do so. In the selection of methods to determine actual emissions, preference should be given to direct measurement wherever feasible, augmented by emissions factors that have been empirically validated. Designing and executing a comprehensive greenhouse gas footprint study based on actual data – the Subcommittee's recommended approach -- is a major project. It requires agreement on measurement equipment, measurement protocols, tools for integrating and analyzing data from different regions, over a multiyear period. Since producer, transmission and distribution pipelines, end-use storage and natural gas many different companies will necessarily be involved. A project of this scale will be expensive. Much of the cost will be borne by firms in the natural gas enterprise that are or will be required to collect and report air emissions. These measurements should be made as rapidly as practicable. Aggregating, assuring quality control and analyzing these data is a substantial task involving significant costs that should be underwritten by the federal government.

It is not clear which government agency would be best equipped to manage such a project. <u>The Subcommittee recommends that planning for this project should begin immediately</u> and that the Office of Science and Technology Policy, should be asked to coordinate an interagency effort to identify sources of funding and lead agency responsibility. This is a pressing question so a clear blueprint and project timetable should be produced within a year.

<u>Third, the Subcommittee recommends that industry and regulators immediately expand efforts to reduce air emissions using proven technologies and practices</u>. Both methane and ozone precursors are of concern. Methane leakage and uncontrolled venting of methane and other air contaminants in the shale gas production should be eliminated except in cases where operators demonstrate capture is technically infeasible, or where venting is necessary for safety reasons and where there is no alternative for capturing emissions. When methane emissions cannot be captured, they should be flared whenever volumes are sufficient to do so.

Ozone precursors should be reduced by using cleaner engine fuel, deploying vapor recovery and other control technologies effective on relevant equipment." Wyoming's emissions rules represent a good starting point for establishing regulatory frameworks and for encouraging industry best practices.

2. Protecting water supply and water quality.

The public understandably wants implementation of standards to ensure shale gas production does not risk polluting drinking water or lakes and streams. The challenge to proper understanding and regulation of the water impacts of shale production is the great diversity of water use in different regional shale gas plays and the different pattern of state and federal regulation of water resources across the country. The U.S. EPA has certain authorities to regulate water resources and it is currently undertaking a two-year study under congressional direction to investigate the potential impacts of hydraulic fracturing on drinking water resources.[18]

Water use in shale gas production passes through the following stages: (1) water acquisition, (2) drilling and hydraulic fracturing (surface formulation of water, fracturing chemicals and sand followed by injection into the shale producing formation at various locations), (3) collection of return water, (4) water storage and processing, and (5) water treatment and disposal.

The Subcommittee offers the following observations with regard to these water issues:

(1) Hydraulic fracturing stimulation of a shale gas well requires between 1 and 5 million gallons of water. While water availability varies across the country, in most regions water used in hydraulic fracturing represents a small fraction of total water consumption. Nonetheless, in some regions and localities there are significant concerns about consumptive water use for shale gas development.[19] There is considerable debate about the water intensity of natural gas compared to other fuels for particular applications such as electric power production.[20]

    One of the commonly perceived risks from hydraulic fracturing is the possibility of leakage of fracturing fluid through fractures into drinking water. Regulators and geophysical experts agree that the likelihood of properly injected fracturing fluid reaching drinking water through fractures is remote where there is a large depth separation between drinking water sources and the producing zone. In the great majority of regions where shale gas is being produced, such separation exists and there are few, if any, documented examples of such migration. An improperly executed fracturing fluid injection can, of course, lead to surface spills and leakage into surrounding shallow drinking water formations. Similarly, a well with poorly cemented casing could potentially leak, regardless of whether the well has been hydraulically fractured.

With respect to stopping surface spills and leakage of contaminated water, the Subcommittee observes that extra measures are now being taken by some operators and regulators to address the public's concern that water be protected. The use of mats, catchments and groundwater monitors as well as the establishment of buffers around surface water resources help ensure against water pollution and should be adopted.

Methane leakage from producing wells into surrounding drinking water wells, exploratory wells, production wells, abandoned wells, underground mines, and natural migration is a greater source of concern. The presence of methane in wells surrounding a shale gas production site is not *ipso facto* evidence of methane leakage from the fractured producing well since methane may be present in surrounding shallow methane deposits or the result of past conventional drilling activity.

However, a recent, credible, peer-reviewed study documented the higher concentration of methane originating in shale gas deposits (through isotopic abundance of C-13 and the presence of trace amounts of higher hydrocarbons) into wells surrounding a producing shale production site in northern Pennsylvania.[21] <u>The Subcommittee recommends several studies be commissioned to confirm the validity of this study and the extent of methane migration that may take place in this and other regions</u>.

(2) Industry experts believe that methane migration from shale gas production, when it occurs, is due to one or another factors: drilling a well in a geological unstable location; <u>loss of well integrity as a result of poor well completion (cementing or casing) or poor production pressure management</u>. Best practice can reduce the risk of this failure mechanism (as discussed in the following section). Pressure tests of the casing and state-of-the-art cement bond logs should be performed to confirm that the methods being used achieve the desired degree of

formation isolation. Similarly, frequent microseismic surveys should be carried out to assure operators and service companies that hydraulic fracture growth is limited to the gas-producing formations. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing (squeeze jobs).

(3) A producing shale gas well yields flow-back and other produced water. The flow-back water is returned fracturing water that occurs in the early life of the well (up to a few months) and includes residual fracturing fluid as well as some solid material from the formation. Produced water is the water displaced from the formation and therefore contains substances that are found in the formation, and may include brine, gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium) and organic compounds. Both the amount and the composition of the flow-back and produced water vary substantially among shale gas plays – for example, in the Eagle Ford area, there is very little returned water after hydraulic fracturing whereas, in the Marcellus, 20 to 40 percent of the fracturing fluid is produced as flow-back water. In the Barnett, there can significant amounts of saline water produced with shale gas if hydraulic fractures propagate downward into the Ellenburger formation.

(4) The return water (flow-back + produced) is collected (frequently from more than a single well), processed to remove commercially viable gas and stored in tanks or an impoundment pond (lined or unlined). For pond storage evaporation will change the composition. Full evaporation would ultimately leave precipitated solids that must be disposed in a landfill. <u>Measurement of the composition of the stored return water should be a routine industry practice</u>.

(5) There are four possibilities for disposal of return water: <u>reuse</u> as fracturing fluid in a new well (several companies, operating in the Marcellus are recycling over 90 percent of the return water); <u>underground injection into disposal wells</u> (this mode of disposal is regulated by the EPA); <u>waste water treatment</u> to produce clean water (though at present, most waste water treatment plants are not equipped with the capability to treat many of the contaminants associated with shale gas waste water); and <u>surface runoff</u> which is forbidden.

Currently, the approach to water management by regulators and industry is not on a "systems basis" where all aspect of activities involving water use is planned, analyzed, and managed on an integrated basis. The difference in water use and regulation in different shale plays means that there will not be a single water management integrated system applicable in all locations. Nevertheless, the Subcommittee believes certain common principles should guide the development of integrated water management and identifies three that are especially important:

- Adoption of a life cycle approach to water management from the beginning of the production process (acquisition) to the end (disposal): all water flows should be tracked and reported quantitatively throughout the process.
- Measurement and public reporting of the composition of water stocks and flow throughout the process (for example, flow-back and produced water, in water ponds and collection tanks).
- Manifesting of all transfers of water among locations.

Early case studies of integrated water management are desirable so as to provide better bases for understanding water use and disposition and opportunities for reduction of risks related to water use. The Subcommittee supports EPA's retrospective and prospective case studies that will be part of the EPA study of hydraulic fracturing impacts on drinking water resources, but these case studies focus on identification of possible consequences rather than the definition of an integrated water management system, including the measurement needs to support it. The Subcommittee believes that development and use of an integrated water management system has the potential for greatly reducing the environmental footprint and risk of water use in shale gas production and recommends that regulators begin working with industry and other stakeholders to develop and implement such systems in their jurisdictions and regionally.

Additionally, agencies should review field experience and modernize rules and enforcement practices – especially regarding well construction/operation, management of flow back and produced water, and prevention of blowouts and surface spills – to ensure robust protection of drinking and surface waters. Specific best practice matters that should receive priority attention from regulators and industry are described below.

3. Background water quality measurements.

At present there are widely different practices for measuring the water quality of wells in the vicinity of a shale gas production site. Availability of measurements in advance of drilling would provide an objective baseline for determining if the drilling and hydraulic fracturing activity introduced any contaminants in surrounding drinking water wells.

The Subcommittee is aware there is great variation among states with respect to their statutory authority to require measurement of water quality of private wells, and that the process of adopting practical regulations that would be broadly acceptable to the public would be difficult. Nevertheless, the value of these measurements for reassuring communities about the impact of drilling on their community water supplies leads the Subcommittee to recommend that states and localities adopt systems for measurement and reporting of background water quality in advance of shale gas production activity. These baseline measurements should be publicly disclosed, while protecting landowner’s privacy.

4. Disclosure of the composition of fracturing fluids.

There has been considerable debate about requirements for reporting all chemicals (both composition and concentrations) used in fracturing fluids. Fracturing fluid refers to the slurry prepared from water, sand, and some added chemicals for high pressure injection into a formation in order to create fractures that open a pathway for release of the oil and gases in the shale. Some states (such as Wyoming, Arkansas and Texas) have adopted disclosure regulations for the chemicals that are added to fracturing fluid, and the U.S. Department of Interior has recently indicated an interest in requiring disclosure for fracturing fluids used on federal lands.

The DOE has supported the establishment and maintenance of a relatively new website, FracFocus.org (operated jointly by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission) to serve as a voluntary chemical registry for individual companies to report all chemicals that would appear on Material Safety Data Sheets (MSDS) subject to certain provisions to protect “trade secrets.” While FracFocus is off to a good start with voluntary reporting growing rapidly, the restriction to MSDS data means that a large universe of chemicals frequently used in hydraulic fracturing treatments goes unreported. MSDS only report chemicals that have been deemed to be hazardous in an occupational setting under standards adopted by OSHA (the Occupational Safety and Health Administration); MSDA reporting does not include other chemicals that might be hazardous if human exposure occurs through environmental pathways. Another limitation of FracFocus is that the information is not maintained as a database. As a result, the ability to search for data is limited and there are no tools for aggregating data.

The Subcommittee believes that the high level of public concern about the nature of fracturing chemicals suggests that the benefit of immediate and complete disclosure of all chemical components and composition of fracturing fluid completely outweighs the restriction on company action, the cost of reporting, and any intellectual property value of proprietary chemicals. The Subcommittee believes that public confidence in the safety of fracturing would be significantly improved by complete disclosure and that the barrier to shield chemicals based on trade secret should be set very high. Therefore the Subcommittee recommends that regulatory entities immediately develop rules to require disclosure of all chemicals used in hydraulic fracturing fluids on both public and private lands. Disclosure should include all chemicals, not just those that appear on MSDS. It should be reported on a well-by-well basis and posted on a publicly available website that includes tools for searching and aggregating data by chemical, well, by company, and by geography.

5. Reducing the use of diesel in shale gas development

Replacing diesel with natural gas or electric power for oil field equipment will decrease harmful air emissions and improve air quality. Although fuel substitution will likely happen over time because of the lower cost of natural gas compared diesel and because of likely future emission restrictions, the Subcommittee recommends conversion from diesel to natural gas for equipment fuel or to electric power where available, as soon as practicable. The process of conversion may be slowed because manufacturers of compression ignition or spark ignition engines may not have certified the engine operating with natural gas fuel for off-road use as required by EPA air emission regulations.[22]

Eliminating the use of diesel as an additive to hydraulic fracturing fluid**.** The Subcommittee believes there is no technical or economic reason to use diesel as a stimulating fluid. Diesel is a refinery product that consists of several components possibly including some toxic impurities such as benzene and other aromatics. (EPA is currently considering permitting restrictions of the use of diesel fuels in hydraulic fracturing under Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) Class II.) Diesel is convenient to use in the oil field because it is present for use fuel for generators and compressors.

Diesel has two uses in hydraulic fracturing and stimulation. In modest quantities diesel is used to solubilize other fracturing chemical such as guar. Mineral oil (a synthetic mixture of C-10 to C-40 hydrocarbons) is as effective at comparable cost. Infrequently, diesel is use as a fracturing fluid in water sensitive clay and shale reservoirs. In these cases, light crude oil that is free of aromatic impurities picked up in the refining process, can be used as a substitute of equal effectiveness and lower cost compared to diesel, as a non-aqueous fracturing fluid.

6. Managing short-term and cumulative impacts on communities, land use, wildlife and ecologies.

Intensive shale gas development can potentially have serious impacts on public health, the environment and quality of life – even when individual operators conduct their activities in ways that meet and exceed regulatory requirements. The combination of impacts from multiple drilling and production operations, support infrastructure (pipelines, road networks, etc.) and related activities can overwhelm ecosystems and communities.

The Subcommittee believes that federal, regional, state and local jurisdictions need to place greater effort on examining these cumulative impacts in a more holistic manner; discrete permitting activity that focuses narrowly on individual activities does not reach to these issues. Rather than suggesting a simple prescription that every jurisdiction should follow to assure adequate consideration of these impacts, the Subcommittee believes that each relevant jurisdiction should develop and implement processes for community engagement and for preventing, mitigating and remediating surface impacts and community impacts from production activities. There are a number of threshold mechanisms that should be considered:

- Optimize use of multi-well drilling pads to minimize transport traffic and needs for new road construction.
- Evaluate water use at the scale of affected watersheds.
- Provide formal notification by regulated entities of anticipated environmental and community impacts.
- Declare unique and/or sensitive areas off-limits to drilling and support infrastructure as determined through an appropriate science-based process.
- Undertake science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.
- Establish effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.
- Mitigate noise, air and visual pollution.

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

Organizing for continuous improvement of "best practice"

In this report, the term "Best Practice" refers to industry techniques or methods that have proven over time to accomplish given tasks and objectives in a manner that most acceptably balances desired outcomes and avoids undesirable consequences. Continuous best practice in an industry refers to the evolution of best practice by adopting process improvements as they are identified, thus progressively improving the level and narrowing the distribution of performance of firms in the industry. Best practice is a particularly helpful management approach in a field that is growing rapidly, where technology is changing rapidly, and involves many firms of different size and technical capacity.

Best practice does not necessarily imply a single process or procedure; it allows for a range of practice that is believed to be equally effective at achieving desired out comes. This flexibility is important because it acknowledges the possibility that different operators in different regions will select different solutions.

The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice through development of standards, diffusion of these standards, and assessing compliance among its members can be an important mechanism for improving shale gas companies' commitment to safety and environmental protection as it carries out its business. The Subcommittee envisions that the industry organization would be governed by a board of directors composed of member companies, on a rotating basis, along with external members, for example from non-governmental organizations and academic institutions, as determined by the board.

Strong regulations and robust enforcement resources and practices are a prerequisite to protecting health, safety and the environment, but the job is easier where companies are motivated and committed to adopting best engineering and environmental practice. Companies have economic incentives to adopt best practice, because it improves operational efficiency and, if done properly, improves safety and environmental protection.

Achievement of best practice requires management commitment, adoption and dissemination of standards that are widely disseminated and periodically updated on the basis of field experience and measurements. A trained work force, motivated to adopt best practice, is also necessary. Creation of an industry organization dedicated to excellence in shale gas operations intended to advance knowledge about best practice and improve the interactions among companies, regulators and the public would be a major step forward.

The Subcommittee is aware that shale gas producers and other groups recognize the value of a best practice management approach and that industry is considering creating a mechanism for encouraging best practice. The design of such a mechanism involves many considerations including the differences in the shale production and regulations in different basins, making most effective use of mechanisms that are currently in place, and respecting the different capabilities of large and smaller operators. The Subcommittee will monitor progress on this important matter and continue to make its views known about the characteristics that such a mechanism and supporting organization should possess to maximize its effectiveness.

It should be stressed that any industry best practice mechanism would need to comply with anti-trust laws and would not replace any existing state or federal regulatory authority.

Priority best practice topics

Air
- Measurement and disclosure of air emissions including VOCs, methane, air toxics, and other pollutants.
- Reduction of methane emission from all shale gas operations

Water
- Integrated water management systems
- Well completion – casing and cementing
- Characterization and disclosure of flow back and other produced water

The Subcommittee has identified a number of promising best practice opportunities. Five examples are given in the call-out box. Two examples are discussed below to give a sense of the opportunities that presented by best practice focus.

Well integrity: an example. Well integrity is an example of the potential power of best practice for shale gas production. Well integrity encompasses the planning, design and execution of a well completion (cementing, casing and well head placement). It is fundamental to good outcomes in drilling oil and gas wells.

Methane leakage to water reservoirs is widely believed to be due to poor well completion, especially poor casing and cementing. Casing and cementing programs should be designed to provide optimal isolation of the gas-producing zone from overlaying formations. The number of cemented casings and the depth ranges covered will depend on local geologic and hydrologic conditions. However, there need to be multiple engineered barriers to prevent communication between hydrocarbons and potable aquifers. In addition, the casing program needs to be designed to optimize the potential success of cementing operations. Poorly cemented cased wells offer pathways for leakage; properly cemented and cased wells do not.

Well integrity is an ideal example of where a best practice approach, adopted by the industry, can stress best practice and collect data to validate continuous improvement. The American Petroleum Institute, for example, has focused on well completion in its standards activity for shale gas production.[23]

At present, however, there is a wide range in procedures followed in the field with regard to casing placement and cementing for shale gas drilling. There are different practices with regard to completion testing and different regulations for monitoring possible gas leakage from the annulus at the wellhead. In some jurisdictions, regulators insist that gas leakage can be vented; others insist on containment with periodic pressure testing. There are no common leakage criteria for intervention in a well that exhibits damage or on the nature of the intervention. It is very likely that over time a focus on best practice in well completion will result in safer operations and greater environmental protection. The best practice will also avoid costly interruptions to normal operations. The regulation of shale gas development should also include inspections at safety-critical stages of well construction and hydraulic fracturing.

<u>Limiting water use by controlling vertical fracture growth</u>: – a second example. While the vertical growth of hydraulic fractures does not appear to have been a causative factor in reported cases where methane from shale gas formations has migrated to the near surface, it is in the best interest of operators and the public to limit the vertical extent of hydraulic fractures to the gas bearing shale formation being exploited. By improving the efficiency of hydraulic fractures, more gas will be produced using less water for fracturing – which has economic value to operators and environmental value for the public.

The vertical propagation of hydraulic fractures results from the variation of earth stress with depth and the pumping pressure during fracturing. The variation of earth stress with depth is difficult to predict, but easy to measure in advance of hydraulic fracturing operations. Operators and service companies should assure that through periodic direct measurement of earth stresses and microseismic monitoring of hydraulic fracturing operations, everything possible is being done to limit the amount of water and additives used in hydraulic fracturing operations.

<u>Evolving best practices must be accompanied by metrics that permit tracking of the progress in improving shale gas operations performance and environmental impacts</u>. The Subcommittee has the impression that the current standard- setting processes do not utilize metrics. Without such metrics and the collection of relevant measured data,

operators lack the ability to track objectively the progress of the extensive process of setting and updating standards.

Research and development needs

The profitability, rapid expansion, and the growing recognition of the scale of the resource mean that oil and gas companies will mount significant R&D efforts to improve performance and lower cost of shale gas exploration and production. In general the oil and gas industry is a technology-focused and technology-driven industry, and it is safe to assume that there will be a steady advance of technology over the coming years.

In these circumstances the federal government has a limited role in supporting R&D. The proper focus should be on sponsoring R&D and analytic studies that address topics that benefit the public or the industry but which do not permit individual firms to attain a proprietary position. Examples are environmental and safety studies, risk assessments, resource assessments, and longer-term R&D (such as research on methane hydrates). Across many administrations, the Office of Management and Budget (OMB) has been skeptical of any federal support for oil and gas R&D, and many Presidents' budget have not included any request for R&D for oil and gas. Nonetheless Congress has typically put money into the budget for oil & gas R&D.

The following table summarizes the R&D outlays of the DOE, EPA, and USGS for unconventional gas:

Unconventional Gas R&D Outlays for Various Federal Agencies ($ millions)					
	FY2008	**FY2009**	**FY2010**	**FY2011**	**FY2012 request**
DOE Unconventional Gas					
EPAct Section 999 Program Funds					
RPSEA Administered	$14	$14	$14	$14	0
NETL Complementary	$9	$9	$9	$4	0
Annual Appropriated Program Funds					
Environmental	$2	$4	$2	0	0
Unconventional Fossil Energy	0	0	$6	0	0
Methane Hydrate projects	$15	$15	$15	$5	$10
Total Department of Energy	$40	$42	$46	$23	$10
Environmental Protection Agency	$0	$0	$1.9	$4.3	$6.1
USGS	$4.5	$4.6	$5.9	$7.4	$7.6
Total Federal R&D	**$44.5**	**$46.6**	**$53.8**	**$34.7**	**$23.7**

Near Term Actions:

The Subcommittee believes that given the scale and rapid growth of the shale gas resource in the nation's energy mix, the federal government should sponsor some R&D for unconventional gas, focusing on areas that have public and industry wide benefit and addresses public concern. The Subcommittee, at this point, is only in a position to offer some initial recommendations, not funding levels or to assignment of responsibility to particular government agencies. The DOE, EPA, the USGS, and DOI Bureau of Land Management all have mission responsibility that justify a continuing, tailored, federal R&D effort.

RPSEA is the Research Partnership to Secure Energy for America, a public/private research partnership authorized by the 2005 Energy Policy Act at a level of $50 million from offshore royalties. Since 2007, the RPSEA program has focused on unconventional gas. The Subcommittee strongly supports the RPSEA program at its authorized level.[24]

The Subcommittee recommends that the relevant agencies, the Office of Science and Technology Policy (OSTP), and OMB discuss and agree on an appropriate mission and level of funding for unconventional natural gas R&D. If requested, the Subcommittee, in the second phase of its work, could consider this matter in greater detail and make recommendations for the Administration's consideration.

In addition to the studies mentioned in the body of the report, the Subcommittee mentions several additional R&D projects where results could reduce safety risk and environmental damage for shale gas operations:

1. Basic research on the relationship of fracturing and micro-seismic signaling.
2. Determination of the chemical interactions between fracturing fluids and different shale rocks – both experimental and predictive.
3. Understanding induced seismicity triggered by hydraulic fracturing and injection well disposal.[25]
4. Development of "green" drilling and fracturing fluids.
5. Development of improved cement evaluation and pressure testing wireline tools assuring casing and cementing integrity.

Longer term prospects for technical advance

The public should expect significant technical advance on shale gas production that will substantially improve the efficiency of shale gas production and that will in turn reduce environmental impact. The expectation of significant production expansion in the future offers a tremendous incentive for companies to undertake R&D to improve efficiency and profitability. The history of the oil and gas industry supports such innovation, in particular greater extraction of the oil and gas in place and reduction in the unit cost of drilling and production.

The original innovations of directional drilling and formation fracturing plausibly will be extended by much more accurate placement of fracturing fluid guided by improved interpretation of micro-seismic signals and improved techniques of reservoir testing. As an example, oil services firms are already offering services that provide near-real-time monitoring to avoid excessive vertical fracturing growth, thus affording better control of fracturing fluid placement. Members of the Subcommittee estimate that an improvement in in efficiency of water use could be between a factor of two and four. There will be countless other innovations as well.

There has already been a major technical innovation – the switch from single well to pad-based drilling and production of multiple wells (up to twenty wells per pad have been drilled). The multi-well pad system allows for enhanced efficiency because of repeating operations at the same site and a much smaller footprint (e.g. concentrated gas gathering systems; many fewer truck trips associated with drilling and completion, especially related to equipment transport; decreased needs for road and pipeline constructions, etc.). It is worth noting that these efficiencies may require pooling acreage into large blocks.

Conclusion

The public deserves assurance that the full economic, environmental and energy security benefits of shale gas development will be realized without sacrificing public health, environmental protection and safety. Nonetheless, accidents and incidents have occurred with shale gas development, and uncertainties about impacts need to be quantified and clarified. Therefore the Subcommittee has highlighted important steps for more thorough information, implementation of best practices that make use of technical innovation and field experience, regulatory enhancement, and focused R&D, to ensure that shale operations proceed in the safest way possible, with enhanced efficiency and minimized adverse impact. If implemented these measures will give the public reason to believe that the nation's considerable shale gas resources are being developed in a way that is most beneficial to the nation.

ANNEX A – CHARGE TO THE SUBCOMMITTEE

From: Secretary Chu

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

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

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

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

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

Membership:

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

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

Consultation with other Agencies:

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

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

Public input:

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

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

Scope of work of the Subcommittee:

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

- well design, siting, construction and completion;
- controls for field scale development;
- operational approaches related to drilling and hydraulic fracturing;
- risk management approaches;
- well sealing and closure;
- surface operations;
- waste water reuse and disposal, water quality impacts, and storm water runoff;

- protocols for transparent public disclosure of hydraulic fracturing chemicals and other information of interest to local communities;
- optimum environmentally sound composition of hydraulic fracturing chemicals, reduced water consumption, reduced waste generation, and lower greenhouse gas emissions;
- emergency management and response systems;
- metrics for performance assessment; and
- mechanisms to assess performance relating to safety, public health and the environment.

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

Delivery of Recommendations and Advice:

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

Other:

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

ANNEX B – MEMBERS OF THE SUBCOMMITTEE

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

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

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

Kathleen McGinty, Kathleen McGinty is a respected environmental leader, having served as President Clinton's Chair of the White House Council on Environmental Quality and Legislative Assistant and Environment Advisor to then-Senator Al Gore.

More recently, she served as Secretary of the Pennsylvania Department of Environmental Protection. Ms. McGinty also has a strong background in energy. She is Senior Vice President of Weston Solutions where she leads the company's clean energy development business. She also is an Operating Partner at Element Partners, an investor in efficiency and renewables. Previously, Ms. McGinty was Chair of the Pennsylvania Energy Development Authority, and currently she is a Director at NRG Energy and Iberdrola USA.

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

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

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

ENDNOTES

[1] http://www.whitehouse.gov/sites/default/files/blueprint_secure_energy_future.pdf
[2] The James Baker III Institute for Public Policy at Rice University has recently released a report on *Shale Gas and U.S. National Security,* Available at: http://bakerinstitute.org/publications/EF-pub-DOEShaleGas-07192011.pdf.

[3] As a shale of total dry gas production in the "lower '48", shale gas was 6 percent in 2006, 8 percent in 2007, at which time its share began to grow rapidly – reaching 12 percent in 2008, 16 percent in 2009, and 24 percent in 2010. In June 2011, it reached 29 percent. Source: Energy Information Adminstration and Lippman Consulting.

[4] Timothy Considine, Robert W. Watson, and Nicholas B. Considine, "The Economy Opportunities of Shale Energy Development," Manhattan Institute, May 2011, Table 2, page 6.

[5] Essentially all fracturing currently uses water at the working fluid. The possibility exists of using other fluids, such as nitrogen, carbon dioxide or foams as the working fluid.

[6] The Department of Energy has a shale gas technology primer available on the web at: http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/Shale_Gas_March_2011.pdf

[7] See the Bureau of Land Management *Gold Book* for a summary description of the DOI's approach:
http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/oil_and_gas.Par.18714.File.dat/OILgas.pdf

[8] http://www.shalegas.energy.gov/

[9] The 2011 *MIT Study on the Future of Natural Gas,* gives an estimate of about 50 widely reported incidents between 2005 and 2009 involving groundwater contamination, surface spills, off-site disposal issues, water issues, air quality and blow outs, Table 2.3 and Appendix 2E. http://web.mit.edu/mitei/research/studies/naturalgas.html

[10] The Ground Water Protection Council and the Interstate Oil and Gas Compact Commission are considering a project to create a *National Oil and Gas Data Portal* with similar a objective, but broader scope to encompass all oil and gas activities.

[11] Information about STRONGER can be found at: http://www.strongerinc.org/

[12] The RBMS project is supported by the DOE Office of Fossil Energy, DOE grant #DE-FE0000880 at a cost of $1.029 million. The project is described at: http://www.netl.doe.gov/technologies/oil-gas/publications/ENVreports/FE0000880_GWPC_Kickoff.pdf

[13] See, for example: John Corra, "Emissions from Hydrofracking Operations and General Oversight Information for Wyoming," presented to the U.S. Department of Energy Natural Gas Subcommittee of the Secretary of Energy Advisory Board, July 13, 2011; Al Armendariz, "Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements," Southern Methodist University, January 2009; Colorado Air Quality Control Commission, "Denver Metro Area & North Front Range Ozone Action Plan," December 12, 2008; Utah Department of Environmental Quality, "2005 Uintah Basin Oil and Gas Emissions Inventory," 2005.

[14] IPCC 2007 –The Physical Science Basis, Section 2.10.2).

[15] Robert W. Howarth, Renee Santoro, and Anthony Ingraffea, *Methane and the greenhouse-gas*

footprint of natural gas from shale formations, Climate Change, The online version of this article (doi:10.1007/s10584-011-0061-5) contains supplementary material.

[16] Timothy J. Skone, *Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States,* DOE, NETL, May 2011, available at: http://www.netl.doe.gov/energy-analyses/pubs/NG_LC_GHG_PRES_12MAY11.pdf

[17] Paulina Jaramillo, W. Michael Griffin, and H. Scott Mathews, *Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, Environmental Science & Technology, 41, 6290-6296 (2007).

[18] The EPA draft hydraulic fracturing study plan is available along with other information about EPA hydraulic fracturing activity at: http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm

[19] See, for example, "South Texas worries over gas industry's water use during drought," Platts, July 5, 2011, found at: http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/3555776; "Railroad Commission, Halliburton officials say amount of water used for fracking is problematic," Abeline Reporter News, July 15, 2011, found at: http://www.reporternews.com/news/2011/jul/15/railroad-commission-halliburton-officials-say-of/?print=1; "Water Use in the Barnett Shale," Texas Railroad Commission Website, updated January 24, 2011, found at: http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php.

[20] See, for example, *Energy Demands on Water Resources, DOE Report to Congress,* Dec 2006, http://www.sandia.gov/energy-water/docs/121-RptToCongress-EWwEIAcomments-FINAL.pdf

[21] Stephen G. Osborna, Avner Vengoshb, Nathaniel R. Warnerb, and Robert B. Jackson, *Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing*, Proceedings of the National Academy of Science, 108, 8172-8176, (2011).

[22] See EPA Certification Guidance for Engines Regulated Under: 40 CFR Part 86 (On-Highway Heavy-Duty Engines) and 40 CFR Part 89 (Nonroad CI Engines); available at: http://www.epa.gov/oms/regs/nonroad/equip-hd/420b98002.pdf

[23] API standards documents addressing hydraulic fracturing are: API HF1, Hydraulic Fracturing Operations-Well Construction and Integrity Guidelines, First Edition/October 2009, API HF2, Water Management Associated with Hydraulic Fracturing, First Edition/June 2010, API HF3, Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing, First Edition/January 2011, available at: http://www.api.org/policy/exploration/hydraulicfracturing/index.cfm

[24] Professor Steven Holditch, one of the Subcommittee members, is chair of the RPSEA governing committee.

[25] Extremely small microearthquakes are triggered as an integral part of shale gas development. While essentially all of these earthquakes are so small as to pose no hazard to the public or facilities (they release energy roughly equivalent to a gallon of milk falling of a kitchen counter), earthquakes of larger (but still small) magnitude have been triggered during hydraulic fracturing operations and by the injection of flow-back water after hydraulic fracturing. It is important to develop a hazard assessment and remediation protocol for triggered earthquakes to allow operators and regulators to know what steps need to be taken to assess risk and modify, as required, planned field operations.

Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

Background Technical Support Document for Proposed Standards

EPA-453/R-11-002
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Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

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FOREWORD

This background technical support document (TSD) provides information relevant to the proposal of New Source Performance Standards (NSPS) for limiting VOC emissions from the Oil and Natural Gas Sector. The proposed standards were developed according to section 111(b)(1)(B) under the Clean Air Act, which requires EPA to review and revise, is appropriate, NSPS standards. The NSPS review allows EPA to identify processes in the oil and natural sector that are not regulated under the existing NSPS but may be appropriate to regulate under NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and SO_2, as well as any additional pollutants that are identified. This document is the result of that review process. Chapter 1 provides introduction on NSPS regulatory authority. Chapter 2 presents an overview of the oil and natural gas sector. Chapter 3 discusses the entire NSPS review process undertaken for this review. Finally, Chapters 4-8 provide information on previously unregulated emissions sources. Each chapter describes the emission source, the estimated emissions (on average) from these sources, potential control options identified to reduce these emissions and the cost of each control option identified. In addition, secondary impacts are estimated and the rationale for the proposed NSPS for each emission source is provided.

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1.0 NEW SOURCE PERFORMANCE STANDARD BACKGROUND

Standards of performance for new stationary sources are established under section 111 of the Clean Air Act (42 U.S.C. 7411), as amended in 1977. Section 111 directs the Administrator to establish standards of performance for any category of new stationary sources of air pollution which "…causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare." This technical support document (TSD) supports the proposed standards, which would control volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from the oil and natural gas sector.

1.1 Statutory Authority

Section 111 of the Clean Air Act (CAA) requires the Environmental Protection Agency Administrator to list categories of stationary sources, if such sources cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for such source categories. A performance standard reflects the degree of emission limitation achievable through the application of the "best system of emission reduction" (BSER) which the EPA determines has been adequately demonstrated. The EPA may consider certain costs and nonair quality health and environmental impact and energy requirements when establishing performance standards. Whereas CAA section 112 standards are issued for existing and new stationary sources, standards of performance are issued for new and modified stationary sources. These standards are referred to as new source performance standards (NSPS). The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to "at least every 8 years review and, if appropriate, revise" performance standards unless the "Administrator determines that such review is not appropriate in light of readily available information on the efficacy" of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to "reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." This level of control is referred to as the best system of emission reduction (BSER). In determining BSER, a technology review is conducted that identifies what emission reduction systems exist and how much the identified systems reduce air pollution in practice. For each control system identified, the costs and secondary air benefits (or disbenefits) resulting from energy requirements and non-air quality impacts such as solid waste generation are also evaluated. This analysis determines BSER. The resultant standard is usually a numerical emissions limit, expressed as a performance level (i.e., a rate-based standard or percent control), that reflects the BSER. Although such standards are based on the BSER, the EPA may not prescribe a particular technology that must be used to comply with a performance standard, except in instances where the Administrator determines it is not feasible to prescribe or enforce a standard of performance. Typically, sources remain free to elect whatever control measures that they choose to meet the emission limits. Upon promulgation, a NSPS becomes a national standard to which all new, modified or reconstructed sources must comply.

1.2 History of Oil and Natural Gas Source Category

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). On June 24, 1985 (50 FR 26122), the EPA promulgated a NSPS for the source category that addressed volatile organic compound (VOC) emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates sulfur dioxide (SO_2) emissions from natural gas processing plants (40 CFR part 60, subpart LLL). Other than natural gas processing plants, EPA has not previously set NSPS for a variety of oil and natural gas operations. These NSPS are relatively narrow in scope as they address emissions only at natural gas processing plants. Specifically, subpart KKK addresses VOC emissions from leaking equipment at onshore natural gas processing plants, and subpart LLL addresses SO_2 emissions from natural gas processing plants.

1.3 NSPS Review Process Overview

CAA section 111(b)(1)(B) requires EPA to review and revise, if appropriate, NSPS standards. First, the existing NSPS were evaluated to determine whether it reflects BSER for the emission affected sources. This review was conducted by examining control technologies currently in use and assessing whether these technologies represent advances in emission reduction techniques compared to the technologies upon which the existing NSPS are based. For each new control technology identified, the potential emission reductions, costs, secondary air benefits (or disbenefits) resulting from energy requirements and non-air quality impacts such as solid waste generation are evaluated. The second step is evaluating whether there are additional pollutants emitted by facilities in the oil and natural gas sector that contribute significantly to air pollution and may reasonably be anticipated to endanger public health or welfare. The final review step is to identify additional processes in the oil and natural gas sector that are not covered under the existing NSPS but may be appropriate to develop NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and SO_2, as well as any additional pollutants that are identified. The entire review process is described in Chapter 3.

2.0 OIL AND NATURAL GAS SECTOR OVERVIEW

The oil and natural gas sector includes operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas. Specifically for oil, the sector includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the sector includes all operations from the well to the customer. The oil and natural gas operations can generally be separated into four segments: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and (4) natural gas distribution. Each of these segments is briefly discussed below.

Oil and natural gas production includes both onshore and offshore operations. Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and "Christmas tree" piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include well drilling, completion and recompletion processes; which includes all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the "pads" where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production sector also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants. None of the operations upstream of the natural gas processing plant (i.e. from the well to the natural gas processing plant) are covered by the existing NSPS. Offshore oil and natural gas production occurs on platform structures that house equipment to extract oil and gas from the ocean or lake floor and that process and/or transfer the oil and gas to storage, transport vessels or onshore. Offshore production can also include secondary platform structures connected to the platform structure, storage tanks associated with the platform structure and floating production and offloading equipment.

There are three basic types of wells: Oil wells, gas wells and associated gas wells. Oil wells can have "associated" natural gas that is separated and processed or the crude oil can be the only product processed. Once the crude oil is separated from the water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar or pipeline. The oil refinery sector is considered separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced "pipeline quality" dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover natural gas liquids or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of natural gas liquids, sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility. Natural gas processing plants are the only operations covered by the existing NSPS.

The pipeline quality natural gas leaves the processing segment and enters the transmission segment. Pipelines in the natural gas transmission segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission segment includes underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration and flow measurement.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. The delivery point where the natural gas leaves the transmission segment and enters the distribution segment is often called the "citygate." Typically, utilities take ownership of the gas at the citygate. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas sector. Primarily, these emissions are organic compounds such as methane, ethane, VOC and organic hazardous air pollutants (HAP). The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide and SO_2 are emitted from production and processing operations that handle and treat sour gas[i]

In addition, there are significant emissions associated with the reciprocating internal combustion engines and combustion turbines that power compressors throughout the oil and natural gas sector. However, emissions from internal combustion engines and combustion turbines are covered by regulations specific to engines and turbines and, thus, are not addressed in this action.

[i] Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2

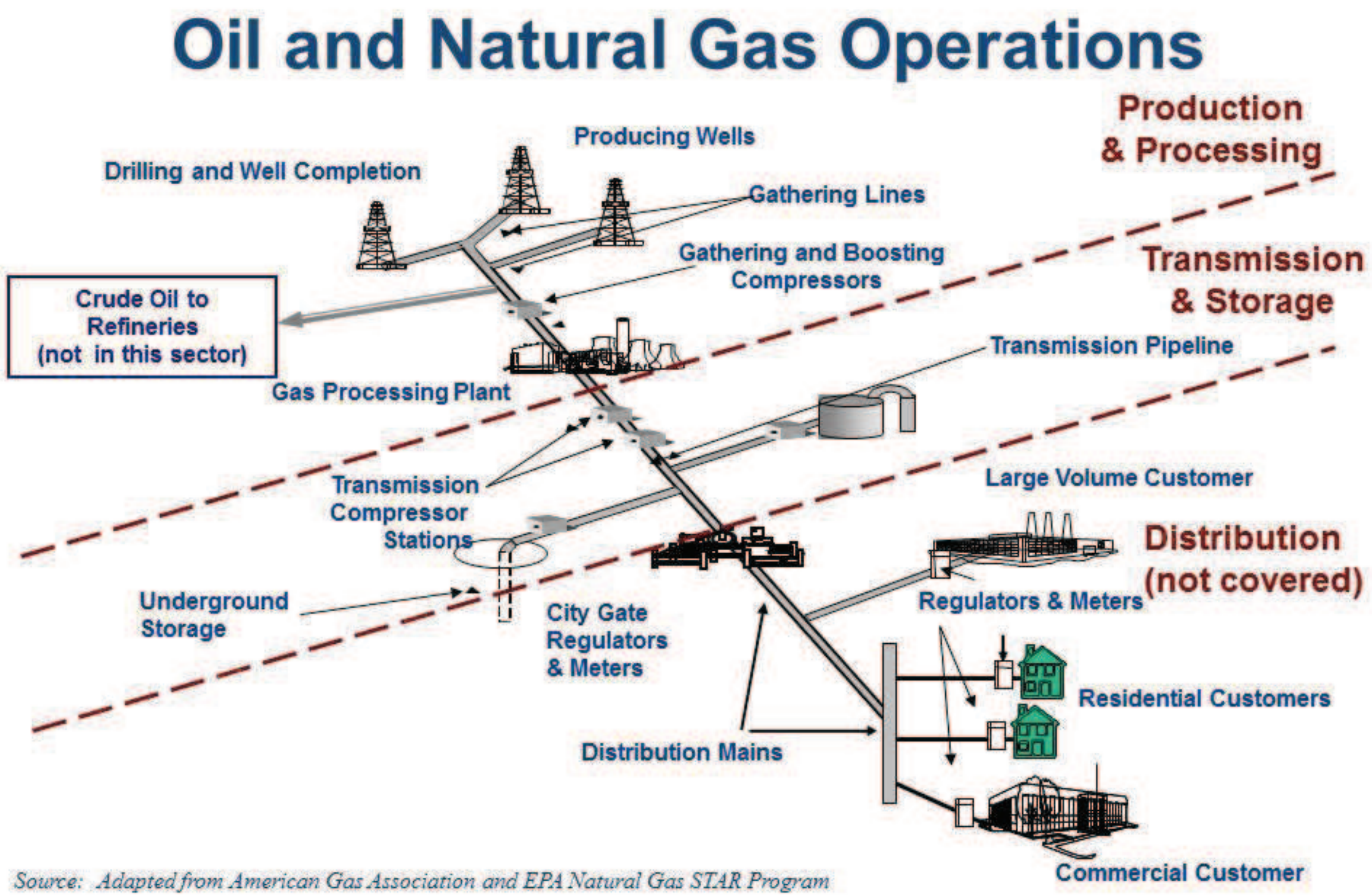

Figure 2-1. Oil and Natural Gas Operations

3.0 NEW SOURCE PERFORMANCE STANDARD REVIEW

As discussed in section 1.2, there are two NSPS that impact the oil and natural gas sector: (1) the NSPS for equipment leaks of VOC at natural gas processing plants (subpart KKK) and (2) the NSPS for SO_2 emissions from sweetening units located at natural gas processing plants (subpart LLL). Because they only address emissions from natural gas processing plants, these NSPS are relatively narrow in scope.

Section 111(b)(1) of the CAA requires the EPA to review and revise, if appropriate, NSPS standards. This review process consisted of the following steps:

1. Evaluation of the existing NSPS to determine whether they continue to reflect the BSER for the emission sources that they address;
2. Evaluation of whether there were additional pollutants emitted by facilities in the oil and natural gas sector that warrant regulation and for which there is adequate information to promulgate standards of performance; and
3. Identification of additional processes in the oil and natural gas sector for which it would be appropriate to develop performance standards, including processes that emit the currently regulated pollutants as well as any additional pollutants identified in step two.

The following sections detail each of these steps.

3.1 Evaluation of BSER for Existing NSPS

Consistent with the obligations under CAA section 111(b), control options reflected in the current NSPS for the Oil and Natural Gas source category were evaluated in order to distinguish if these options still represent BSER. To evaluate the BSER options for equipment leaks the following was reviewed: EPA's current leak detection and repair (LDAR) programs, the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database, and emerging technologies that have been identified by partners in the Natural Gas STAR program.[1]

3.1.1 BSER for VOC Emissions from Equipment Leaks at Natural Gas Processing Plants

The current NSPS for equipment leaks of VOC at natural gas processing plants (40 CFR part 60, subpart KKK) requires compliance with specific provisions of 40 CFR part 60, subpart VV, which is a LDAR program, based on the use of EPA Method 21 to identify equipment leaks. In addition to the subpart VV requirements, the LDAR requirements in 40 CFR part 60, subpart VVa were also reviewed. This LDAR program is considered to be more stringent than the subpart VV requirements, because it has lower component leak threshold definitions and more frequent monitoring, in comparison to the subpart VV program. Furthermore, subpart VVa requires monitoring of connectors, while subpart VV does not. Options based on optical gas imaging were also reviewed.

The currently required LDAR program for natural gas processing plants (40 CFR part 60, subpart KKK) is based on EPA Method 21, which requires the use of an organic vapor analyzer to monitor components and to measure the concentration of the emissions in identifying leaks. Although there have been advancements in the use of optical gas imaging to detect leaks from these same types of components, these instruments do not yet provide a direct measure of leak concentrations. The instruments instead provide a measure of a leak relative to an instrument specific calibration point. Since the promulgation of 40 CFR part 60, subpart KKK (which requires Method 21 leak measurement monthly), the EPA has updated the 40 CFR part 60 General Provisions to allow the use of advanced leak detection tools, such as optical gas imaging and ultrasound equipment as an alternative to the LDAR protocol based on Method 21 leak measurements (see 40 CFR 60.18(g)). The alternative work practice allowing use of these advanced technologies includes a provision for conducting a Method 21-based LDAR check of the regulated equipment annually to verify good performance.

In considering BSER for VOC equipment leaks at natural gas processing plants, four options were evaluated. One option evaluated consists of changing from a 40 CFR part 60, subpart VV-level program, which is what 40 CFR part 60, subpart KKK currently requires, to a 40 CFR part 60, subpart VVa program, which applies to new synthetic organic chemical plants after 2006. Subpart VVa lowers the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm, and requires the monitoring of connectors. In our analysis of these impacts, it was estimated that, for a typical natural gas processing plant, the incremental cost effectiveness of changing from the current subpart VV-level program to a subpart VVa-level program using Method 21 is $3,352 per ton of VOC reduction.

In evaluating 40 CFR part 60, subpart VVa-level LDAR at processing plants, the individual types of components (valves, connectors, pressure relief devices and open-ended lines) were also analyzed separately to determine cost effectiveness for individual components. Detailed discussions of these component-by-component analyses are provided in Chapter 8. Cost effectiveness ranged from $144 per ton of VOC (for valves) to $4,360 per ton of VOC (for connectors), with no change in requirements for pressure relief devices and open-ended lines.

Another option evaluated for gas processing plants was the use of optical gas imaging combined with an annual EPA Method 21 check (i.e., the alternative work practice for monitoring equipment for leaks at 40 CFR 60.18(g)). It was previously determined that the VOC reduction achieved by this combination of optical gas imaging and Method 21 would be equivalent to reductions achieved by the 40 CFR part 60, subpart VVa-level program. Based on the emission reduction level, the cost effectiveness of this option was estimated to be $6,462 per ton of VOC reduction. This analysis was based on the facility purchasing an optical gas imaging system costing $85,000. However, at least one manufacturer was identified that rents the optical gas imaging systems. That manufacturer rents the optical gas imaging system for $3,950 per week. Using this rental cost in place of the purchase cost, the VOC cost effectiveness of the monthly optical gas imaging combined with annual Method 21 inspection visits is $4,638 per ton of VOC reduction.[i]

A third option evaluated consisted of monthly optical gas imaging without an annual Method 21 check. The annual cost of the monthly optical gas imaging LDAR program was estimated to be $76,581 based on camera purchase, or $51,999 based on camera rental. However, it is not possible to quantify the VOC emission reductions achieved by an optical imaging program alone, therefore the cost effectiveness of this option could not be determined. Finally, a fourth option was evaluated that was similar to the third option, except that the optical gas imaging would be performed annually rather than monthly. For this option, the annual cost was estimated to be $43,851, based on camera purchase, or $18,479, based on camera rental.

Because the cost effectiveness of options 3 and 4 could not be estimated, these options could not be identified as BSER for reducing VOC leaks at gas processing plants. Because options 1 and 2 achieve equivalent VOC reduction and are both cost effective, both options 1 and 2 reflect BSER for LDAR for natural gas processing plants. As mentioned above, option 1 is the LDAR in 40 CFR part 60, subpart VVa and option 2 is the alternative work practice at 40 CFR 60.18(g) and is already available to use as an alternative to subpart VVa LDAR.

3.1.2 BSER for SO_2 Emissions from Sweetening Units at Natural Gas Processing Plants

For 40 CFR part 60, subpart LLL, control systems for SO_2 emissions from sweetening units located at natural gas processing plants were evaluated, including those followed by a sulfur recovery unit. Subpart

[i] Because optical gas imaging is used to view multiple pieces of equipment at a facility during one leak survey, options involving imaging are not amenable to a component by component analysis.

LLL provides specific standards for SO_2 emission reduction efficiency, on the basis of sulfur feed rate and the sulfur content of the natural gas.

According to available literature, the most widely used process for converting H_2S in acid gases (i.e., H_2S and CO_2) separated from natural gas by a sweetening process (such as amine treating) into elemental sulfur is the Claus process. Sulfur recovery efficiencies are higher with higher concentrations of H_2S in the feed stream due to the thermodynamic equilibrium limitation of the Claus process. The Claus sulfur recovery unit produces elemental sulfur from H_2S in a series of catalytic stages, recovering up to 97-percent recovery of the sulfur from the acid gas from the sweetening process. Further, sulfur recovery is accomplished by making process modifications or by employing a tail gas treatment process to convert the unconverted sulfur compounds from the Claus unit.

In addition, process modifications and tail gas treatment options were also evaluated at the time 40 CFR part 60, subpart LLL was proposed.[ii] As explained in the preamble to the proposed subpart LLL, control through sulfur recovery with tail gas treatment may not always be cost effective, depending on sulfur feed rate and inlet H_2S concentrations. Therefore, other methods of increasing sulfur recovery via process modifications were evaluated.

As shown in the original evaluation for the proposed subpart LLL, the performance capabilities and costs of each of these technologies are highly dependent on the ratio of H_2S and CO_2 in the gas stream and the total quantity of sulfur in the gas stream being treated. The most effective means of control was selected as BSER for the different stream characteristics. As a result, separate emissions limitations were developed in the form of equations that calculate the required initial and continuous emission reduction efficiency for each plant. The equations were based on the design performance capabilities of the technologies selected as BSER relative to the gas stream characteristics.[iii] The emission limit for sulfur feed rates at or below 5 long tons per day, regardless of H_2S content, was 79 percent. For facilities with sulfur feed rates above 5 long tons per day, the emission limits ranged from 79 percent at an H_2S content below 10 percent to 99.8 percent for H_2S contents at or above 50 percent.

To review these emission limitations, a search was performed of the RBLC database[1] and state regulations. No State regulations were identified that included emission limitations more stringent than 40 CFR part 60, subpart LLL. However, two entries in the RBLC database were identified having SO_2

[ii] 49 FR 2656, 2659-2660 (1984).
[iii] 49 FR 2656, 2663-2664 (1984).

emission reductions of 99.9 percent. One entry is for a facility in Bakersfield, California, with a 90 long ton per day sulfur recovery unit followed by an amine-based tailgas treating unit. The second entry is for a facility in Coden, Alabama, with a sulfur recovery unit with a feed rate of 280 long tons of sulfur per day, followed by selective catalytic reduction and a tail gas incinerator. However, neither of these entries contained information regarding the H_2S contents of the feed stream. Because the sulfur recovery efficiency of these large sized plants was greater than 99.8 percent, the original data was reevaluated. Based on the available cost information, a 99.9 percent efficiency is cost effective for facilities with a sulfur feed rate greater than 5 long tons per day and H_2S content equal to or greater than 50 percent. Based on this review, the maximum initial and continuous efficiency for facilities with a sulfur feed rate greater than 5 long tons per day and a H_2S content equal to or greater than 50 percent is raised to 99.9 percent.

The search of the RBLC database did not uncover information regarding costs and achievable emission reductions to suggest that the emission limitations for facilities with a sulfur feed rate less than 5 long tons per day or H_2S content less than 50 percent should be modified. Therefore, there were not any identifiable changes to the emissions limitations for facilities with sulfur feed rate and H_2S content less than 5 long tons per day and 50 percent, respectively.[1]

3.2 Additional Pollutants

The two current NSPS for the Oil and Natural Gas source category address emissions of VOC and SO_2. In addition to these pollutants, sources in this source category also emit a variety of other pollutants, most notably, air toxics. However, there are NESHAP that address air toxics from the oil and natural gas sector, specifically 40 CFR subpart HH and 40 CFR subpart HHH.

In addition, processes in the Oil and Natural Gas source category emit significant amounts of methane. The 1990 - 2009 U.S. GHG Inventory estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries) to be 251.55 MMtCO2e (million metric tons of CO2-equivalents (CO2e)).[iv] The emissions estimated from well completions and recompletions exclude a significant number of wells completed in tight sand plays, such as the Marcellus, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays (being considered as a planned improvement in development of the 2010 Inventory).

[iv] U.S. EPA. Inventory of U.S. Greenhouse Gas Inventory and Sinks. 1990 - 2009. http://www.epa.gov/climatechange/emissions/downloads10/US-GHGInventory2010_ExecutiveSummary.pdf

This adjustment would increase the 2009 Inventory estimate by 76.74 MMtCO2e. The total methane emissions from Petroleum and Natural Gas Systems, based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus, is 328.29 MMtCO2e.

Although this proposed rule does not include standards for regulating the GHG emissions discussed above, EPA continues to assess these significant emissions and evaluate appropriate actions for addressing these concerns. Because many of the proposed requirements for control of VOC emissions also control methane emissions as a co-benefit, the proposed VOC standards would also achieve significant reduction of methane emissions.

Significant emissions of oxides of nitrogen (NO_x) also occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors that move natural gas through the system, and from combustion of natural gas in heaters and boilers. While these engines, turbines, heaters and boilers are co-located with processes in the oil and natural gas sector, they are not in the Oil and Natural Gas source category and are not being addressed in this action. The NO_x emissions from engines and turbines are covered by the Standards of Performance for Stationary Spark Internal Combustion Engines (40 CFR part 60, subpart JJJJ) and Standards of Performance for Stationary Combustion Turbines (40 CFR part 60, subpart KKKK), respectively.

An additional source of NO_x emissions would be pit flaring of VOC emissions from well completions. As discussed in Chapter 4 Well completions, pit flaring is one option identified for controlling VOC emissions. Because there is no way of directly measuring the NO_x produced, nor is there any way of applying controls other than minimizing flaring, flaring would only be required for limited conditions.

3.3 Additional Processes

The current NSPS only cover emissions of VOC and SO_2 from one type of facility in the oil and natural gas sector, which is the natural gas processing plant. This is the only type of facility in the Oil and Natural Gas source category where SO_2 is expected to be emitted directly; although H_2S contained in sour gas[v] forms SO_2 as a product of oxidation when oxidized in the atmosphere or combusted in boilers and heaters in the field. These field boilers and heaters are not part of the Oil and Natural Gas source category and are generally too small to be regulated by the NSPS covering boilers (i.e., they have a heat

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[v] Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2.

input of less than 10 million British Thermal Units per hour). They may, however, be included in future rulemakings.

In addition to VOC emissions from gas processing plants, there are numerous sources of VOC throughout the oil and natural gas sector that are not addressed by the current NSPS. Pursuant to CAA section 111(b), a modification of the listed category will now include all segments of the oil and natural gas industry for regulation. In addition, VOC standards will now cover additional processes at oil and natural gas operations. These include NSPS for VOC from gas well completions and recompletions, pneumatic controllers, compressors and storage vessels. In addition, produced water ponds may also be a potentially significant source of emissions, but there is very limited information available regarding these emissions. Therefore, no options could be evaluated at this time. The remainder of this document presents the evaluation for each of the new processes to be included in the NSPS.

3.4 References

1 Memorandum to Bruce Moore from Brad Nelson and Phil Norwood. Crude Oil and Natural Gas Production NSPS Technology Reviews. EC/R Incorporated. July 28, 2011.

4.0 WELL COMPLETIONS AND RECOMPLETIONS

In the oil and natural gas sector, well completions and recompletions contain multi-phase processes with various sources of emissions. One specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during recompletion activities that involve re-drilling or re-fracturing an existing well. This chapter describes completions and recompletions, and provides estimates for representative wells in addition to nationwide emissions. Control techniques employed to reduce emissions from flowback gas venting during completions and recompletions are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for reducing flowback emissions during completions and recompletions.

4.1 Process Description

4.1.1 Oil and Gas Well Completions

All oil and natural gas wells must be "completed" after initial drilling in preparation for production. Oil and natural gas completion activities not only will vary across formations, but can vary between wells in the same formation. Over time, completion and recompletion activities may change due to the evolution of well characteristics and technology advancement. Conventional gas reservoirs have well defined formations with high resource allocation in permeable and porous formations, and wells in conventional gas reservoirs have generally not required stimulation during production. Unconventional gas reservoirs are more dispersed and found in lower concentrations and may require stimulation (such as hydraulic fracturing) to extract gas.[1]

Well completion activities include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Surface components, including wellheads, pumps, dehydrators, separators, tanks, and gathering lines are installed as necessary for production to begin. The flowback stage of a well completion is highly variable but typically lasts between 3 and 10 days for the average well.[2]

Developmental wells are drilled within known boundaries of a proven oil or gas field, and are located near existing well sites where well parameters are already recorded and necessary surface equipment is in place. When drilling occurs in areas of new or unknown potential, well parameters such as gas composition, flow rate, and temperature from the formation need to be ascertained before surface facilities required for production can be adequately sized and brought on site. In this instance, exploratory (also referred to as "wildcat") wells and field boundary delineation wells typically either vent or combust the flowback gas.

One completion step for improving gas production is to fracture the reservoir rock with very high pressure fluid, typically a water emulsion with a proppant (generally sand) that "props open" the fractures after fluid pressure is reduced. Natural gas emissions are a result of the backflow of the fracture fluids and reservoir gas at high pressure and velocity necessary to clean and lift excess proppant to the surface. Natural gas from the completion backflow escapes to the atmosphere during the reclamation of water, sand, and hydrocarbon liquids during the collection of the multi-phase mixture directed to a surface impoundment. As the fracture fluids are depleted, the backflow eventually contains a higher volume of natural gas from the formation. Due to the additional equipment and resources involved and the nature of the backflow of the fracture fluids, completions involving hydraulic fracturing have higher costs and vent substantially more natural gas than completions not involving hydraulic fracturing.

Hydraulic fracturing can and does occur in some conventional reservoirs, but it is much more common in "tight" formations. Therefore, this analysis assumes hydraulic fracturing is performed in tight sand, shale, and coalbed methane formations. This analysis defines tight sand as sandstones or carbonates with an in situ permeability (flow rate capability) to gas of less than 0.1 millidarcy.[i]

"Energized fractures" are a relatively new type of completion method that injects an inert gas, such as carbon dioxide or nitrogen, before the fracture fluid and proppant. Thus, during initial flowback, the gas stream will first contain a high proportion of the injected gas, which will gradually decrease overtime.

4.1.2 Oil and Gas Well Recompletions

Many times wells will need supplementary maintenance, referred to as recompletions (these are also referred to as workovers). Recompletions are remedial operations required to maintain production or minimize the decline in production. Examples of the variety of recompletion activities include

[i] A darcy (or darcy unit) and millidarcies (mD) are units of permeability Converted to SI units, 1 darcy is equivalent to 9.869233×10^{-13} m² or 0.9869233 (µm)². This conversion is usually approximated as 1 (µm)².

completion of a new producing zone, re-fracture of a previously fractured zone, removal of paraffin buildup, replacing rod breaks or tubing tears in the wellbore, and addressing a malfunctioning downhole pump. During a recompletion, portable equipment is conveyed back to the well site temporarily and some recompletions require the use of a service rig. As with well completions, recompletions are highly specialized activities, requiring special equipment, and are usually performed by well service contractors specializing in well maintenance. Any flowback event during a recompletion, such as after a hydraulic fracture, will result in emissions to the atmosphere unless the flowback gas is captured.

When hydraulic re-fracturing is performed, the emissions are essentially the same as new well completions involving hydraulic fracture, except that surface gas collection equipment will already be present at the wellhead after the initial fracture. The backflow velocity during re-fracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

Backflow emissions are not a direct result of produced water. Backflow emissions are a result of free gas being produced by the well during well cleanup event, when the well also happens to be producing liquids (mostly water) and sand. The high rate backflow, with intermittent slugs of water and sand along with free gas, is typically directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels. Therefore, nearly all of the backflow emissions originate from the recompletion process but are vented as the backflow enters the impoundment or vessels. Minimal amounts of emissions are caused by the fluid (mostly water) held in the impoundment or vessels since very little gas is dissolved in the fluid when it enters the impoundment or vessels.

4.2. Emission Data and Emissions Factors

4.2.1 Summary of Major Studies and Emission Factors

Given the potential for significant emissions from completions and recompletions, there have been numerous recent studies conducted to estimate these emissions. In the evaluation of the emissions and emission reduction options for completions and recompletions, many of these studies were consulted. Table 4-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Documents [3]	EPA	2010	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 [4,5]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry [6, 7, 8, 9]	Gas Research Institute /US Environmental Protection Agency	1996	Nationwide	X	X
Methane Emissions from the US Petroleum Industry (Draft) [10]	EPA	1996	Nationwide	X	
Methane Emissions from the US Petroleum Industry [11]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [12]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories [13]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[14]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements [15]	Environmental Defense Fund	2009	Regional	X	X
Emissions from Oil and Natural Gas Production Facilities [16]	Texas Commission for Environmental Quality	2007	Regional	X	X
Availability, Economics and Production of North American Unconventional Natural Gas Supplies 1	Interstate Natural Gas Association of America	2008	Nationwide		

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Petroleum and Natural Gas Statistical Data[17]	U.S. Energy Information Administration	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations [18]	EPA	1999		X	
Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program [19]	New York State Department of Environmental Conservation	2009	Regional	X	X
Natural Gas STAR Program [20, 21, 22, 23, 24, 25]	EPA	2000-2010	Nationwide/ Regional	X	X

4.2.2 Representative Completion and Recompletion Emissions

As previously mentioned, one specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during the completion of a new well or during recompletion activities that involve re-drilling or re-fracturing of an existing well. For this analysis, well completion and recompletion emissions are estimated as the venting of emissions from the well during the initial phases of well preparation or during recompletion maintenance and/or re-fracturing of an existing well.

As previously stated, this analysis assumes wells completed/recompleted with hydraulic fracturing are found in tight sand, shale, or coal bed methane formations. A majority of the available emissions data for recompletions is for vertically drilled wells. It is projected that in the future, a majority of completions and recompletions will predominantly be performed on horizontal wells. However, there is not enough history of horizontally drilled wells to make a reasonable estimation of the difference in emissions from recompletions of horizontal versus vertical wells. Therefore, for this analysis, no distinction was made between vertical and horizontal wells.

As shown in Table 4-1, methane emissions from oil and natural gas operations have been measured, analyzed and reported in studies spanning the past few decades. The basic approach for this analysis was to approximate methane emissions from representative oil and gas completions and recompletions and then estimate volatile organic compounds (VOC) and hazardous air pollutants (HAP) using a representative gas composition.[26] The specific gas composition ratios used for gas wells were 0.1459 pounds (lb) VOC per lb methane (lb VOC/lb methane) and 0.0106 lb HAP/lb methane. The specific gas composition ratios used for oil wells were 0.8374 pounds lb VOC/lb methane and 0.0001 lb HAP/lb methane.

The EPA's analysis to estimate methane emissions conducted in support of the Greenhouse Gas Mandatory Reporting Rule (Subpart W), which was published in the *Federal Register* on November 30, 2010 (75 FR 74458), was the foundation for methane emission estimates from natural gas completions with hydraulic fracturing and recompletions with hydraulic fracturing. Methane emissions from oil well completions, oil well recompletions, natural gas completions without hydraulic fracturing, and natural gas recompletions without hydraulic fracturing were derived directly from the EPA's Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 (Inventory).[4] A summary of emissions for a representative model well completion or recompletion is found in Table 4-2.

Table 4-2. Uncontrolled Emissions Estimates from Oil and Natural Gas Well Completions and Recompletions

Well Completion Category	Emissions (Mcf/event)	Emissions (tons/event)		
	Methane	Methane[a]	VOC[b]	HAP[c]
Natural Gas Well Completion without Hydraulic Fracturing	38.6	0.8038	0.12	0.009
Natural Gas Well Completion with Hydraulic Fracturing	7,623	158.55	23.13	1.68
Oil Well Completions	0.34	0.0076	0.00071	0.0000006
Natural Gas Well Recompletion without Hydraulic Fracturing	2.59	0.0538	0.0079	0.0006
Natural Gas Well Recompletion with Hydraulic Fracturing	7,623	158.55	23.13	1.68
Oil Well Recompletions	0.057	0.00126	0.001	0.0000001

Minor discrepancies may exist due to rounding.

a. Reference 4, Appendix B., pgs 84-89. The conversion used to convert methane from volume to weight is 0.0208 tons methane is equal to 1 Mcf of methane. It is assumed methane comprises 83.081 percent by volume of natural gas from gas wells and 46.732 percent by volume of methane from oil wells.
b. Assumes 0.1459 lb VOC /lb methane for natural gas wells and 0.8374 lb VOC/lb methane for oil wells.
c. Assumes 0.0106 lb HAP/lb methane for natural gas wells and 0.0001 lb HAP/lb methane for oil wells.

4.3 Nationwide Emissions from New Sources

4.3.1 Overview of Approach

The first step in this analysis is to estimate nationwide emissions in absence of the proposed rulemaking, referred to as the baseline emissions estimate. In order to develop the baseline emissions estimate, the number of completions and recompletions performed in a typical year was estimated and then multiplied by the expected uncontrolled emissions per well completion listed in Table 4-2. In addition, to ensure no emission reduction credit was attributed to sources already controlled under State regulations, it was necessary to account for the number of completions/recompletions already subject to State regulations as detailed below. In order to estimate the number of wells that are already controlled under State regulations, existing well data was analyzed to estimate the percentage of currently controlled wells. This percentage was assumed to also represent the wells that would have been controlled in absence of a federal regulation and applied to the number of well completions estimated for future years.

4.3.2 Number of Completions and Recompletions

The number of new well completions was estimated using the National Energy Modeling System (NEMS). NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration (EIA). NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy economy from the current year to 2035. EIA is legally required to make the NEMS source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of NEMS, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues. NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions.

New well completion estimates are based on predictions from the NEMS Oil and Gas Supply Model, drawing upon the same assumptions and model used in the Annual Energy Outlook 2011 Reference Case. New well completions estimates were based on total successful wells drilled in 2015 (the year of analysis for regulatory impacts) for the following well categories: natural gas completions without hydraulic fracturing, natural gas completions with hydraulic fracturing, and oil well completions.

Successful wells are assumed to be equivalent to completed wells. Meanwhile, it was assumed that new dry wells would be abandoned and shut in and would not be completed. Therefore estimates of the number of dry wells were not included in the activity projections or impacts discussion for exploratory and developmental wells. Completion estimates are based on successful developmental and exploratory wells for each category defined in NEMS that includes oil completions, conventional gas completions and unconventional gas completions. The NEMS database defines unconventional reservoirs as those in shale, tight sand, and coalbed methane formations and distinguishes those from wells drilled in conventional reservoirs. Since hydraulic fracturing is most common in unconventional formations, this analysis assumes new successful natural gas wells in shale, tight sand, and coalbed methane formations are completed with hydraulic fracturing. New successful natural gas wells in conventional formations are assumed to be completed without hydraulic fracturing.

The number of natural gas recompletions with hydraulic fracturing (also referred to as a re-fracture), natural gas recompletions without hydraulic fracturing and oil well recompletions was based on well count data found in the HPDI® database.[ii, iii] The HPDI database consists of oil and natural gas well information maintained by a private organization that provides parameters describing the location, operator, and production characteristics. HPDI® collects information on a well basis such as the operator, state, basin, field, annual gas production, annual oil production, well depth, and shut-in pressure, all of which is aggregated from operator reports to state governments. HPDI was used to estimate the number of recompleted wells because the historical well data from HPDI is a comprehensive resource describing existing wells. Well data from 2008 was used as a base year since it was the most recent available data at the time of this analysis and is assumed to represent the number of recompletions that would occur in a representative year. The number of hydraulically fractured natural gas recompletions was estimated by estimating each operator and field combination found in the HPDI database and multiplying by 0.1 to represent 10 percent of the wells being re-fractured annually (as assumed in Subpart W's Technical Supporting Document3). This results in 14,177 total natural gas recompletions with hydraulic fracturing in the U.S. for the year 2008; which is assumed to depict a representative year. Non-fractured

[ii] HPDI, LLC is a private organization specializing in oil and gas data and statistical analysis. The HPDI database is focused on historical oil and gas production data and drilling permit data.

[iii] For the State of Pennsylvania, the most recent drilling information available from HPDI was for 2003. Due to the growth of oil and gas operations occurring in the Marcellus region in Pennsylvania, this information would not accurately represent the size of the industry in Pennsylvania for 2006 through 2008. Therefore, information from the Pennsylvania's Department of Environmental Protection was used to estimate well completion activities for this region. Well data from remaining states were based on available information from HPDI. From
<http://www.marcellusreporting.state.pa.us/OGREReports/Modules/DataExports/DataExports.aspx

recompletions were based on well data for 2008 in HPDI. The number of estimated well completions and recompletions for each well source category is listed in Table 4-3.

4.3.3 Level of Controlled Sources in Absence of Federal Regulation

As stated previously, to determine the impact of a regulation, it is first necessary to determine the current level of emissions from the sources being evaluated, or baseline emissions. To more accurately estimate baseline emissions for this analysis, and to ensure no emission reduction credit was attributed for sources already being controlled, it was necessary to evaluate the number of completions and recompletions already subject to regulation. Therefore, the number of completions and recompletions already being controlled in the absence of federal regulation was estimated based on the existing State regulations that require control measures for completions and recompletions. Although there may be regulations issued by other local ordinances for cities and counties throughout the U.S., wells impacted by these regulations were not included in this analysis because well count data are not available on a county or local ordinance level. Therefore, the percentage calculated based on the identified State regulations should be considered a conservative estimate.

In order to determine the number of completions and recompletions that are already controlled under State regulations, EIA historical well count data was analyzed to determine the percentage of new wells currently undergoing completion and recompletion in the States identified as having existing controls.[iv] Colorado (CO) and Wyoming (WY) were the only States identified as requiring controls on completions prior to NSPS review. The State of Wyoming's Air Quality Division (WAQD) requires operators to complete wells without flaring or venting where the following criteria are met: (1) the flowback gas meets sales line specifications and (2) the pressure of the reservoir is high enough to enable REC. If the above criteria are not met, then the produced gas is to be flared.[27] The WAQD requires that, "emissions of VOC and HAP associated with the flaring and venting of hydrocarbon fluids (liquids and gas) associated with well completion and recompletion activities shall be eliminated to the extent practicable by routing the recovered liquids into storage tanks and routing the recovered gas into a gas sales line or collection system." Similar to WY, the Colorado Oil and Gas Conservation Commission (COOGCC) requires REC for both oil and natural gas wells.[28] It was assumed for this analysis that the ratio of natural wells in CO and WY to the total number of wells in the U.S. represents the percentage of controlled wells for well completions. The ratio of wells in WY to the number of total nationwide wells

[iv] See EIA's The Number of Producing Wells, http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm

Table 4-3: Estimated Number of Total Oil and Natural Gas Completions and Recompletions for a Typical Year

Well Completion Category	Estimated Number of Total Completions and Recompletions[a]	Estimated Number of Controlled Completions and Recompletions	Estimated Number of Uncontrolled Completions and Recompletions[b]
Natural Gas Well Completions without Hydraulic Fracturing*	7,694		7,694
Exploratory Natural Gas Well Completions with Hydraulic Fracturing**	446		446
Developmental Natural Gas Well Completions with Hydraulic Fracturing[c]	10,957	1,644	9,313
Oil Well Completions[d]	12,193		12,193
Natural Gas Well Recompletions without Hydraulic Fracturing	42,342		42,342
Natural Gas Well Recompletions with Hydraulic Fracturing‡‡	14,177	2,127	12,050
Oil Well Recompletions‡	39,375		39,375

a. Natural gas completions and recompletions without hydraulic fracturing are assumed to be uncontrolled at baseline.
b. Fifteen percent of natural gas well completions with hydraulic fracturing are assumed as controlled at baseline.
c. Oil well completions and recompletions are assumed to be uncontrolled at baseline.
d. Fifteen percent of natural gas well recompletions with hydraulic fracturing are assumed to be controlled at baseline.

was assumed to represent the percentage of controlled well recompletions as it was the only State identified as having regulations directly regulated to recompletions.

From this review it was estimated that 15 percent of completions and 15 percent of recompletions are controlled in absence of federal regulation. It is also assumed for this analysis that only natural gas wells undergoing completion or recompletion with hydraulic fracturing are controlled in these States. Completions and recompletions that are performed without hydraulic fracturing, in addition to oil well completions and recompletions were assumed to not be subject to State regulations and therefore, were assumed to not be regulated at baseline. Baseline emissions for the controlled completions and recompletions covered by regulations are assumed to be reduced by 95 percent from the use of both REC and combustion devices that may be used separately or in tandem, depending on the individual State regulation.[v] The final activity factors for uncontrolled completions and uncontrolled recompletions are also listed in Table 4-3.

4.3.4 Emission Estimates

Using the estimated emissions, number of uncontrolled and controlled wells at baseline, described above, nationwide emission estimates for oil and gas well completions and recompletions in a typical year were calculated and are summarized in Table 4-4. All values have been independently rounded to the nearest ton for estimation purposes. As the table indicates, hydraulic fracturing significantly increases the magnitude of emissions. Completions and recompletions without hydraulic fracturing have lower emissions, while oil completions and recompletions have even lower emissions in comparison.

4.4 Control Techniques

4.4.1 Potential Control Techniques

Two techniques were considered that have been proven to reduce emissions from well completions and recompletions: REC and completion combustion. One of these techniques, REC, is an approach that not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented. The second technique, completion combustion, destroys the organic compounds. Both of these techniques are discussed in the following sections, along with estimates of the impacts of their application for a representative well. Nationwide impacts of chosen regulatory options are discussed in

[v] Percentage of controls by flares versus REC were not determined, so therefore, the count of controlled wells with REC versus controlled wells with flares was not determined and no secondary baseline emission impacts were calculated.

Table 4-4. Nationwide Baseline Emissions from Uncontrolled Oil and Gas Well Completions and Recompletions

Well Completion Category	Uncontrolled Methane Emissions per event (tpy)	Number of Uncontrolled Wells[a]	Baseline Nationwide Emissions (tons/year)[a]		
			Methane[b]	VOC[c]	HAP[d]
Natural Gas Well Completions without Hydraulic Fracturing	0.8038	7,694	6,185	902	66
Exploratory Natural Gas Well Completions with Hydraulic Fracturing	158.55	446	70,714	10,317	750
Developmental Natural Gas Well Completions with Hydraulic Fracturing	158.55	9,313	1,476,664	215,445	15,653
Oil Well Completions	0.0076	12,193	93	87	.008
Natural Gas Well Recompletions without Hydraulic Fracturing	0.0538	42,342	2,279	332	24
Natural Gas Well Recompletions with Hydraulic Fracturing	158.55	12,050	1,910,549	278,749	20,252
Oil Well Recompletions	0.00126	39,375	50	47	.004

Minor discrepancies may be due to rounding.

a. Baseline emissions include emissions from uncontrolled wells plus five percent of emissions from controlled sources. The Baseline emission reductions listed in the Regulatory Impacts (Table 4-9) represents only emission reductions from uncontrolled sources.
b. The number of controlled and uncontrolled wells estimated based on State regulations.
c. Based on the assumption that VOC content is 0.1459 pounds VOC per pound methane for natural gas wells and 0.8374 pounds VOC per pound methane for oil wells This estimate accounts for 5 percent of emissions assumed as vented even when controlled. Does not account for secondary emissions from portion of gas that is directed to a combustion device.
d. Based on the assumption that HAP content is 0.0106 pounds HAP per pound methane for natural gas wells and 0.0001 pounds HAP per pound methane for oil wells. This estimate accounts for 5 percent of emissions assumed as vented even when controlled. Does not account for secondary emissions from portion of gas that is directed to a combustion device.

section 4.5.

4.4.2 Reduced Emission Completions and Recompletions

4.4.2.1 Description

Reduced emission completions, also referred to as “green” or “flareless” completions, use specially designed equipment at the well site to capture and treat gas so it can be directed to the sales line. This process prevents some natural gas from venting and results in additional economic benefit from the sale of captured gas and, if present, gas condensate. Additional equipment required to conduct a REC may include additional tankage, special gas-liquid-sand separator traps, and a gas dehydrator.[29] In many cases, portable equipment used for RECs operate in tandem with the permanent equipment that will remain after well drilling is completed. In other instances, permanent equipment is designed (e.g. oversized) to specifically accommodate initial flowback. Some limitations exist for performing RECs since technical barriers fluctuate from well to well. Three main limitations include the following for RECs:

- Proximity of pipelines. For exploratory wells, no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields. The State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area that has never had oil and gas well production prior to that drilling instance (i.e., a wildcat well).[30] In instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that existing surface REC equipment may be located near an exploratory well, which would allow for a REC.

- Pressure of produced gas. During each stage of the completion/recompletion process, the pressure of flowback fluids may not be sufficient to overcome the sales line backpressure. This pressure is dependent on the specific sales line pressure and can be highly variable. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line. Another control option is compressor applications. One application is gas lift which is accomplished by withdrawing gas from the sales line, boosting its pressure, and routing it down the well casing to push the fracture fluids up the tubing. The increased pressure facilitates flow into the separator and then the sales line where the lift gas becomes part of the normal flowback that can be recovered during a REC. Another potential compressor application is to boost pressure of the flowback gas after it exits the separator. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate.

- Inert gas concentration. If the concentration of inert gas, such as nitrogen or carbon dioxide, in the flowback gas exceeds sales line concentration limits, venting or combustion of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

4.4.2.2. Effectiveness

RECs are an effective emissions reduction method for only natural gas completions and recompletions performed with hydraulic fracturing based on the estimated flowback emissions described in Section 4.2. The emissions reductions vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on several experiences presented at Natural Gas STAR technology transfer workshops, this analysis assumes 90 percent of flowback gas can be recovered during a REC.[31] Any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95 percent reduction in emissions.

4.4.2.3 Cost Impacts

All completions incur some costs to a company. Performing a REC will add to these costs. Equipment costs associated with RECs vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment, such as a glycol dehydrator, is already installed or is planned to be in place at the well site as normal operations, costs may be reduced as this equipment can be used or resized rather than installing a portable dehydrator for temporary use during the completion. Some operators normally install equipment used in RECs, such as sand traps and three-phase separators, further reducing incremental REC costs.

Costs of performing a REC are projected to be between $700 and $6,500 per day, with representative well completion flowback lasting 3 to 10 days.2 This cost range is the incremental cost of performing a REC over a traditional completion, where typically the gas is vented or combusted because there is an absence of REC equipment. Since RECs involve techniques and technologies that are new and continually evolving, and these cost estimates are based on the state of the industry in 2006 (adjusted to 2008 US dollars). [vi] Cost data used in this analysis are qualified below:

- $700 per day (equivalent to $806 per day in 2008 dollars) represents completion and recompletion costs where key pieces of equipment, such as a dehydrator or three phase separator, are already found on site and are of suitable design and capacity for use during flowback.

- $6,500 per day (equivalent to $7,486 in 2008 dollars) represents situations where key pieces of equipment, such as a dehydrator or three-phase separator, are temporarily brought on site and then relocated after the completion.

Costs were assessed based on an average of the above data (for costs and number of days per completion), resulting in an average incremental cost for a REC of $4,146 per day (2008 dollars) for an average of 7 days per completion. This results in an overall incremental cost of $29,022 for a REC versus an uncontrolled completion. An additional $691 (2008 dollars) was included to account for transportation and placement of equipment, bringing total incremental costs estimated at $29,713. Reduced emission completions are considered one-time events per well; therefore annual costs were conservatively assumed to be the same as capital costs. Dividing by the expected emission reductions, cost-effectiveness for VOC is $1,429 per ton, with a methane co-benefit of $208 per ton. Table 4-5 provides a summary of REC cost-effectiveness.

Monetary savings associated with additional gas captured to the sales line was also estimated based on a natural gas price of $4.00[vii] per thousand cubic feet (Mcf).[32] It was assumed that all gas captured would be included as sales gas. Therefore, assuming that 90 percent of the gas is captured and sold, this equates

[vi] The Chemical Engineering Cost Index was used to convert dollar years. For REC, the 2008 value equals 575.4 and the 2006 value equals 499.6.

[vii] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the price, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings. The value of natural gas condensate recovered during the REC would also be significant depending on the gas composition. This value was not incorporated into the monetary savings in order to not overstate savings.

Table 4-5. Reduced Emission Completion and Recompletion Emission Reductions and Cost Impacts Summary

Well Completion Category	Emission Reduction Per Completion/Recompletion (tons/year)[a]			Total Cost Per Completion/ Recompletion[b] ($/event)	VOC Cost Effectiveness ($/ton)[c]		Methane Cost Effectiveness ($/ton)	
	VOC	Methane	HAP		without savings	with savings	without savings	with savings
Natural Gas Completions and Recompletions with Hydraulic Fracturing	20.8	142.7	1.5	29,713	1,429	net savings	208	net savings

Minor discrepancies may be due to rounding.

a. This represents a ninety percent reduction from baseline for the average well.
b. Total cost for reduced emission completion is expressed in terms of incremental cost versus a completion that vents emissions. This is based on an average incremental cost of $4,146 per day for an average length of completion flowback lasting 7 days and an additional $691 for transportation and set up.
c. Cost effectiveness has been rounded to the nearest dollar.

to a total recovery of 8,258 Mcf of natural gas per completion or recompletion with hydraulic fracturing. The estimated value of the recovered natural gas for a representative natural gas well with hydraulic fracturing is approximately $33,030. In addition we estimate an average of 34 barrels of condensate is recovered per completion or recompletion. Assuming a condensate value of $70 per barrel (bbl), this result is an income due to condensate sales around $2,380.[33] When considering these savings from REC, for a completion or recompletion with hydraulic fracturing, there is a net savings on the order of $5,697 per completion.

4.4.2.4 Secondary Impacts

A REC is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., nitrogen oxides, particulate matter, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to REC.

4.4.3 Completion Combustion Devices

4.4.3.1 Description

Completion combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.[34] Completion combustion devices are used to control VOC in many industrial settings, since the completion combustion device can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[35] Completion combustion devices commonly found on drilling sites are rather crude and portable, often installed horizontally due to the liquids that accompany the flowback gas. These flares can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead. However, the flow directed to a completion combustion device may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. Sometimes referred to as pit flares, these types of combustion devices do not employ an actual control device, and are not capable of being tested or monitored for efficiency. They do provide a means of minimizing vented gas and is preferable to venting. For the purpose of this analysis, the term completion combustion device represents all types of combustion devices including pit flares.

4.4.3.2 Effectiveness

The efficiency of completion combustion devices, or exploration and production flares, can be expected to achieve 95 percent, on average, over the duration of the completion or recompletion. If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it is more reliable to install an igniter fueled by a consistent and continuous ignition source. This scenario would be especially true for energized fractures where the initial flowback concentration will be extremely high in inert gases. This analysis assumes use of a continuous ignition source with an independent external fuel supply is assumed to achieve an average of 95 percent control over the entire flowback period. Additionally, because of the nature of the flowback (i.e., with periods of water, condensate, and gas in slug flow), conveying the entire portion of this stream to a flare or other control device is not always feasible. Because of the exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (e.g., dry, windy conditions, proximity to residences, etc.). As a result, we are aware that owners and operators may not be able to flare unrecoverable gas safely in every case.

Federal regulations require industrial flares meet a combustion efficiency of 98 percent or higher as outlined in 40 CFR 60.18. This statute does not apply to completion combustion devices. Concerns have been raised on applicability of 40 CFR 60.18 within the oil and gas industry including for the production segment.[30, 36, 37] The design and nature of completion combustion devices must handle multiphase flow and stream compositions that vary during the flowback period. Thus, the applicability criterion that specifies conditions for flares used in highly industrial settings may not be appropriate for flares typically used to control emissions from well completions and recompletions.

4.4.3.3 Cost Impacts

An analysis depicting the cost for wells including completion combustion devices was conducted for the Petroleum Services Association of Canada (PSAC) [38] in 2009 by N.L. Fisher Supervision and Engineering, Ltd.[viii] The data corresponds to 34 gas wells for various types of formations, including coal bed methane and shale. Multiple completion methods were also examined in the study including hydraulic and energized fracturing. Using the cost data points from these natural gas well completions,

[viii] It is important to note that outliers were excluded from the average cost calculation. Some outliers estimated the cost of production flares to be as low as $0 and as high as $56,000. It is expected that these values are not representative of typical flare costs and were removed from the data set. All cost data found in the PSAC study were aggregated values of the cost of production flares and other equipment such as tanks. It is possible the inclusion of the other equipment is not only responsible for the outliers, but also provides a conservatively high estimate for completion flares.

an average completion combustion device cost is approximately $3,523 (2008 dollars).[ix] As with the REC, because completion combustion devices are purchased for these one-time events, annual costs were conservatively assumed to be equal to the capital costs.

It is assumed that the cost of a continuous ignition source is included in the combustion completion device cost estimations. It is understood that multiple completions and recompletions can be controlled with the same completion combustion device, not only for the lifetime of the combustion device but within the same yearly time period. However, to be conservative, costs were estimated as the total cost of the completion combustion device itself, which corresponds to the assumption that only one device will control one completion per year. The cost impacts of using a completion combustion device to reduce emissions from representative completions/recompletions are provided in Table 4-6. Completion combustion devices have a cost-effectiveness of $161 per ton VOC and a co-benefit of $23 per ton methane for completions and recompletions with hydraulic fracturing.

4.4.3.4 Secondary Impacts

Noise and heat are the two primary undesirable outcomes of completion combustion device operation. In addition, combustion and partial combustion of many pollutants also create secondary pollutants including nitrogen oxides (NO_x), carbon monoxide (CO), sulfur oxides (SO_x, carbon dioxide (CO_2), and smoke/particulates (PM). The degree of combustion depends on the rate and extent of fuel mixing with air and the temperature maintained by the flame. Most hydrocarbons with carbon-to-hydrogen ratios greater than 0.33 are likely to smoke.[34] Due to the high methane content of the gas stream routed to the completion combustion device, it suggests that there should not be smoke except in specific circumstances (e.g., energized fractures). The stream to be combusted may also contain liquids and solids that will also affect the potential for smoke. Soot can typically be eliminated by adding steam. Based on current industry trends in the design of completion combustion devices and in the decentralized nature of completions, virtually no completion combustion devices include steam assistance.[34]

Reliable data for emission factors from flare operations during natural gas well completions are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing

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[ix] The Chemical Engineering Cost Index was used to convert dollar years. For the combustion device the 2009 value equals 521.9. The 2009 average value for the combustion device is $3,195.

Table 4-6. Emission Reduction and Cost-effectiveness Summary for Completion Combustion Devices

Well Completion Category	Emission Reduction Per Completion/Workover (tons/year)[a]			Total Capital Cost Per Completion Event ($)*	VOC Cost Effectiveness	Methane Cost Effectiveness
	VOC	Methane	HAP		($/ton)[b]	($/ton)
Natural Gas Well Completions without Hydraulic Fracturing	0.11	0.76	0.0081	3,523	31,619	4,613
Natural Gas Well Completions with Hydraulic Fracturing	21.9	150.6	1.597		160	23
Oil Well Completions	0.01	0.007	0.0000007		520,580	488,557
Natural Gas Well Recompletions without Hydraulic Fracturing	0.007	0.051	0.0005		472,227	68,889
Natural Gas Well Recompletions with Hydraulic Fracturing	21.9	150.6	1.597		160	23
Oil Well Recompletions	0.00	0.001	0.0000001		3,134,431	2,941,615

Minor discrepancies may be due to rounding.

a. This assumes one combustion device will control one completion event per year. This should be considered a conservative estimate, since it is likely multiple completion events will be controlled with the same combustion unit in any given year. Costs are stated in 2008 dollars.

80 percent propylene and 20 percent propane.[34] These emissions factors, however, are the best indication for secondary pollutants from flare operations currently available. These secondary emission factors are provided are provided in Table 4-7.

Since this analysis assumed pit flares achieve 95 percent efficiency over the duration of flowback, it is likely the secondary emission estimations are lower than actuality (i.e. AP-42 assumes 98 percent efficiency). In addition due, to the potential for the incomplete combustion of natural gas across the pit flare plume, the likelihood of additional NO_x formulating is also likely. The degree of combustion is variable and depends on the on the rate and extent of fuel mixing with air and on the flame temperature. Moreover, the actual NO_x (and CO) emissions may be greatly affected when the raw gas contains hydrocarbon liquids and water. For these reasons, the nationwide impacts of combustion devices discussed in Section 4.5 should be considered minimum estimates of secondary emissions from combustion devices.

4.5 Regulatory Options

The REC pollution prevention approach would not result in emissions of CO, NO_x, and PM from the combustion of the completion gases in the flare, and would therefore be the preferred option. As discussed above, REC is only an option for reducing emissions from gas well completions/workovers with hydraulic fracturing. Taking this into consideration, the following regulatory alternatives were evaluated:

- Regulatory Option 1: Require completion combustion devices for conventional natural gas well completions and recompletions;
- Regulatory Option 2: Require completion combustion devices for oil well completions and recompletions;
- Regulatory Option 3: Require combustion devices for all completions and recompletions;
- Regulatory Option 4: Require REC for all completions and recompletions of hydraulically fractured wells;
- Regulatory Option 5: Require REC and combustion operational standards for natural gas well completions with hydraulic fracturing, with the exception of exploratory, and delineation wells;
- Regulatory Option 6: Require combustion operational standards for exploratory and delineation wells; and

Table 4-7. Emission Factors from Flare Operations from AP-42 Guidelines Table 13.4-1[a]

Pollutant	Emission Factor ($lb/10^6$ Btu)
Total Hydrocarbon[b]	0.14
Carbon Monoxide	0.37
Nitrogen Oxides	0.068
Particular Matter[c]	0-274
Carbon Dioxide[d]	60

a. Based on combustion efficiency of 98 percent.
b. Measured as methane equivalent.
c. Soot in concentration values: nonsmoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.
d. Carbon dioxide is measured in kg CO2/MMBtu and is derived from the carbon dioxide emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

- Regulatory Option 7: Require REC and combustion operational standards for all natural gas well recompletions with hydraulic fracturing.

The following sections discuss these regulatory options.

4.5.1 Evaluation of Regulatory Options

The first two regulatory options (completion combustion devices for conventional natural gas well completions and recompletions and completion combustion devices for oil well completions and recompletions) were evaluated first. As shown in Table 4-6, the cost effectiveness associated with controlling conventional natural gas and oil well completions and recompletions ranges from $31,600 per ton VOC to over $3.7 million per ton VOC. Therefore, Regulatory Options 1 and 2 were rejected due to the high cost effectiveness.

The next regulatory option, to require completion combustion devices for all completions and recompletions, was considered. Under Regulatory Option 3, all of the natural gas emitted from the well during flowback would be destroyed by sending flowback gas through a combustion unit. Not only would this regulatory option result in the destruction of a natural resource with no recovery of salable gas, it also would result in an increase in emissions of secondary pollutants (e.g., nitrogen oxides, carbon monoxide, etc.). Therefore, Regulatory Option 3 was also rejected.

The fourth regulatory option would require RECs for all completions and recompletions of hydraulically fractured wells. As stated previously, RECs are not feasible for all well completions, such as exploratory wells, due to their distance from sales lines, etc. Further, RECs are also not technically feasible for each well at all times during completion and recompletion activities due to the variability of the pressure of produced gas and/or inert gas concentrations. Therefore, Regulatory Option 4 was rejected.

The fifth regulatory option was to require an operational standard consisting of a combination of REC and combustion for natural gas well completions with hydraulic fracturing. As discussed for Regulatory Option 4, RECs are not feasible for every well at all times during completion or recompletion activities due to variability of produced gas pressure and/or inert gas concentrations. In order to allow for wellhead owners and operators to continue to reduce emissions when RECs are not feasible due to well characteristics (e.g, wellhead pressure or inert gas concentrations), Regulatory Option 5 also allows for the use of a completion combustion device in combination with RECs.

Under Regulatory Option 5, a numerical limit was considered, but was rejected in favor of an operational standard. Under section 111(h)(2) of the CAA, EPA can set an operational standard which represents the best system of continuous emission reduction, provided the following criteria are met:

> "(A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or
>
> (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations."

As discussed in section 4.4.3, emissions from a completion combustion device cannot be measured or monitored to determine efficiency making an operational standard appropriate. Therefore, an operational standard under this regulatory option consists of a combination of REC and a completion combustion device to minimize the venting of natural gas and condensate vapors to the atmosphere, but allows venting in lieu of combustion for situations in which combustion would present safety hazards, other concerns, or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Sources would also be required, under this regulatory option, to maintain documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion. It was also evaluated whether Regulatory Option 5 should apply to all well completions, including exploratory and delineation wells.

As discussed previously, one of the technical limitations of RECs is that they are not feasible for use at some wells due to their proximity to pipelines. Section 111(b)(2) of the CAA allows EPA to "…distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing…." performance standards. Due to their distance from sales lines, and the relatively unknown characteristics of the formation, completion activities occurring at exploratory or delineation wells were considered to be a different "type" of activity than the types of completion activities occurring at all other gas wells. Therefore, two subcategories of completions were identified: *Subcategory 1* wells are all natural gas wells completed with hydraulic fracturing that do not fit the definition of exploratory or delineation wells. *Subcategory 2* wells are natural gas wells that meet the following definitions of exploratory or delineation wells:

- Exploratory wells are wells outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists or

- Delineation wells means a well drilled in order to determine the boundary of a field or producing reservoir.

Based on this subcategorization, Regulatory Option 5 would apply to the Subcategory 1 wells and a sixth regulatory option was developed for Subcategory 2 wells.

Regulatory Option 6 requires an operational standard for combustion for the Subcategory 2 wells. As described above, REC is not an option for exploratory and delineation wells due to their distance from sales lines. As with the Regulatory Option 5, a numerical limitation is not feasible. Therefore, this regulatory option requires an operational standard where emissions are minimized using a completion combustion device during completion activities at Subcategory 2 wells, with an allowance for venting in situations where combustion presents safety hazards or other concerns or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Consistent with Regulatory Option 5, records would be required to document the overall duration of the completion event, the duration of combustion, the duration of venting, and specific reasons for venting in lieu of combustion.

The final regulatory option was considered for recompletions. Regulatory Option 7 requires an operational standard for a combination of REC and a completion combustion device for all recompletions with hydraulic fracturing performed on new and existing natural gas wells. Regulatory Option 7 has the same requirements as Regulatory Option 5. Subcategorization similar to Regulatory Option 5 was not necessary for recompletions because it was assumed that RECs would be technically feasible for recompletions at all types of wells since they occur at wells that are producing and thus proximity to a sales line is not an issue. While evaluating this regulatory option, it was considered whether or not recompletions at existing wells should be considered modifications and subject to standards.

The affected facility under the New Source Performance Standards (NSPS) is considered to be the wellhead. Therefore, a new well drilled after the proposal date of the NSPS would be subject to emission control requirements. Likewise, wells drilled prior to the proposal date of the NSPS would not be subject to emission control requirements unless they underwent a modification after the proposal date. Under section 111(a) of the Clean Air Act, the term “modification” means:

> "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."

The wellhead is defined as the piping, casing, tubing, and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. In order to fracture an existing well during recompletion, the well would be re-perforated, causing physical change to the wellbore and casing and therefore a physical change to the wellhead, the affected facility. Additionally, much of the emissions data on which this analysis is based demonstrates that hydraulic fracturing results in an increase in emissions. Thus, recompletions using hydraulic fracturing result in an increase in emissions from the existing well producing operations. Based on this understanding of the work performed in order to recomplete the well, it was determined that a recompletion would be considered a modification under CAA section 111(a) and thus, would constitute a new wellhead affected facility subject to NSPS. Therefore, Regulatory Option 7 applies to recompletions using hydraulic fracturing at new and existing wells.

In summary, Regulatory Options 1, 2, 3, and 4 were determined to be unreasonable due to cost considerations, other impacts or technical feasibility and thereby rejected. Regulatory Options 5, 6, and 7 were determined to be applicable to natural gas wells and were evaluated further.

4.5.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Options 5, 6, and 7 which were selected as viable options for setting standards for completions and recompletions.

4.5.2.1 Primary Environmental Impacts of Regulatory Options

Regulatory Options 5, 6, and 7 were selected as options for setting standards for completions and regulatory options as follows:

- Regulatory Option 5: Operational standard for completions with hydraulic fracturing for Subcategory 1 wells (i.e., wells which do not meet the definition of exploratory or delineation wells), which requires a combination of REC with combustion, but allows for venting during specified situations.

- Regulatory Option 6: An operational standard for completions with hydraulic fracturing for exploratory and delineation wells (i.e., Subcategory 2 wells) which requires completion combustion devices with an allowance for venting during specified situations.

- Regulatory Option 7: An operational standard equivalent to Regulatory Option 5 which applies to recompletions with hydraulic fracturing at new and existing wells.

The number of completions and recompletions that would be subject to the regulatory options listed above was presented in Table 4-3. It was estimated that there would be 9,313 uncontrolled developmental natural gas well completions with hydraulic fracturing subject to Regulatory Option 5. Regulatory Option 6 would apply to 446 uncontrolled exploratory natural gas well completions with hydraulic fracturing, and 12,050 uncontrolled recompletions at existing wells would be subject to Regulatory Option 7.[x]

Table 4-8 presents the nationwide emission reduction estimates for each regulatory option. It was estimated that RECs in combination with the combustion of gas unsuitable for entering the gathering line, can achieve an overall 95 percent VOC reduction over the duration of the completion operation. The 95 percent recovery was estimated based on 90 percent of flowback being captured to the sales line and assuming an additional 5 percent of the remaining flowback would be sent to the combustion device. Nationwide emission reductions were estimated by applying this 95 percent VOC reduction to the uncontrolled baseline emissions presented in Table 4-4.

4.5.2.2 Cost Impacts

Cost impacts of the individual control techniques (RECs and completion combustion devices) were presented in section 4.4. For Regulatory Option 6, the costs for completion combustion devices presented in Table 4-6 for would apply to Subcategory 2 completions. The cost per completion event was estimated to be $3,523. Applied to the 446 estimated Subcategory 2 completions, the nationwide costs were estimated to be $1.57 million. Completion combustion devices are assumed to achieve an overall 95 percent combustion efficiency. Since the operational standards for Regulatory Options 5 and 7 include both REC and completion combustion devices, an additional cost impact analysis was

[x] The number of uncontrolled recompletions at new wells is not included in this analysis. Based on the assumption that wells are recompleted once every 10 years, any new wells that are drilled after the date of proposal of the standard would not likely be recompleted until after the year 2015, which is the date of this analysis. Therefore, impacts were not estimated for recompletion of new wells, which will be subject to the standards.

Table 4-8. Nationwide Emission and Cost Analysis of Regulatory Option

Well Completion Category	Number of Sources subject to NSPS[a]	Annual Cost Per Completion Event ($)[b]	Nationwide Emission Reductions (tpy)[c]			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
			VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 5 (operational standard for REC and combustion)												
Subcategory 1: Natural gas Completions with Hydraulic Fracturing	9,313	33,237	204,134	1,399,139	14,831	1,516	net savings	221	net savings	309.5	309.5	(20.24)
Regulatory Option 6 (operational standard for combustion)												
Subcategory 2: Natural gas Completions with Hydraulic Fracturing	446	3,523	9,801	67,178	712	160	160	23	23	1.57	1.57	1.57
Regulatory Option 7 (operational standard for REC and combustion)												
Natural Gas Well Recompletions with Hydraulic Fracturing	12,050	33,237	264,115	1,810,245	19,189	1,516	net savings	221	net savings	400.5	400.5	(26.18)

Minor discrepancies may be due to rounding.

a. Number of sources in each well completion category that are uncontrolled at baseline as presented in Table 4-3.
b. Costs per event for Regulatory Options 5 and 7 are calculated by adding the costs for REC and completion combustion device presented in Tables 4-5 and 4-6, respectively. Cost per event for Regulatory Option 6 is presented for completion combustion devices in Table 4-6.
c. Nationwide emission reductions calculated by applying the 95 percent emission reduction efficiency to the uncontrolled nationwide baseline emissions in Table 4-4.

performed to analyze the nationwide cost impacts of these regulatory options. The total incremental cost of the operational standard for Subcategory 1 completions and for recompletions is estimated at around $33,237, which includes the costs in Table 4-5 for the REC equipment and transportation in addition to the costs in Table 4-6 for the completion combustion device. Applying the cost for the combined REC and completion combustion device to the estimated 9,313 Subcategory 1 completions, the total nationwide cost was estimated to be $309.5 million, with a net annual savings estimated around $20 million when natural gas savings are considered. A cost of $400.5 million was estimated for recompletions, with an overall savings of around $26 million when natural gas savings are considered. The VOC cost effectiveness for Regulatory Options 5 and 7 was estimated at around $1,516 per ton, with a methane co-benefit of $221 per ton.

4.5.2.3 Secondary Impacts

Regulatory Options 5, 6 and 7 all require some amount of combustion; therefore the estimated nationwide secondary impacts are a direct result of combusting all or partial flowback emissions. Although, it is understood the volume of gas captured, combusted and vented may vary significantly depending on well characteristics and flowback composition, for the purpose of estimating secondary impacts for Regulatory Options 5 and 7, it was assumed that ninety percent of flowback is captured and an additional five percent of the remaining gas is combusted. For both Subcategory 1 natural gas well completions with hydraulic fracturing and for natural gas well recompletions with hydraulic fracturing, it is assumed around 459 Mcf of natural gas is combusted on a per well basis. For Regulatory Option 6, Subcategory 2 natural gas completions with hydraulic fracturing, it is assumed that 95 percent (8,716 Mcf) of flowback emissions are consumed by the combustion device. Tons of pollutant per completion event was estimated assuming 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas and applying the AP-42 emissions factors listed in Table 4-7.

From category 1 well completions and from recompletions, it is estimated 0.02 tons of NO_x are produced per event. This is based on assumptions that 5 percent of the flowback gas is combusted by the combustion device. From category 2 well completions, it is estimated 0.32 tons of NO_x are produced in secondary emissions per event. This is based on the assumption 95 percent of flowback gas is combusted by the combustion device. Based on the estimated number of completions and recompletions, the proposed regulatory options are estimated to produce around 507 tons of NO_x in secondary emissions nationwide from controlling all or partial flowback by combustion. Table 4-9 summarizes the estimated secondary emissions of the selected regulatory options.

Table 4-9 Nationwide Secondary Impacts of Selected Regulatory Options[a]

Pollutant	Regulatory Options 5[b] Subcategory 1 Natural Gas Well Completions with Hydraulic Fracturing		Regulatory Option 6[c] Subcategory 2 Natural Gas Well Completions with Hydraulic Fracturing		Regulatory Options 7[b] Natural Gas Well Recompletions with Hydraulic Fracturing	
	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)
Total Hydrocarbons	0.03	326	0.66	296	0.03	422
Carbon Monoxide	0.09	861	1.76	783	0.09	1,114
Nitrogen Oxides	0.02	158	0.32	144	0.02	205
Particulate Matter	0.00000002	0.0002	0.011	5	0.00000002	0.0003
Carbon Dioxide	33.06	307,863	628	280,128	33.06	398,341

a. Nationwide impacts are based on AP-42 Emission Guidelines for Industrial Flares as outlined in Table 4-7. As such, these emissions should be considered the minimum level of secondary emissions expected.
b. The operational standard (Regulatory Options 5 and 7) combines REC and combustion is assumed to capture 90 percent of flowback gas. Five percent of the remaining flowback is assumed to be consumed in the combustion device. Therefore, it is estimated 459 Mcf is sent to the combustion device per completion event. This analysis assumes there are 9,313 Subcategory 1 wells and 12,050 recompletions.
c. Assumes 8,716 Mcf of natural gas is sent to the combustion unit per completion. This analysis assumes 446 exploratory wells fall into this category.
d. Based on 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas.

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5.0 PNEUMATIC CONTROLLERS

The natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature, and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are used throughout the oil and natural gas sector as part of the instrumentation to control the position of valves. This chapter describes pneumatic devices including their function and associated emissions. Options available to reduce emissions from pneumatic devices are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for pneumatic devices.

5.1 Process Description

For the purpose of this document, a pneumatic controller is a device that uses natural gas to transmit a process signal or condition pneumatically and that may also adjust a valve position based on that signal, with the same bleed gas and/or a supplemental supply of power gas. In the vast majority of applications, the natural gas industry uses pneumatic controllers that make use of readily available high-pressure natural gas to provide the required energy and control signals. In the production segment, an estimated 400,000 pneumatic devices control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. There are around 13,000 gas pneumatic controllers located in the gathering, boosting and processing segment that control and monitor temperature, liquid, and pressure levels. In the transmission segment, an estimated 85,000 pneumatic controllers actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.[1]

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate control of a valve. In these “gas-driven” pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs: (1) continuous bleed devices are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) snap-acting devices release gas only when they open or close a valve or as they throttle the gas flow; and (3) self-contained devices release gas to a downstream pipeline instead of to the atmosphere. This analysis assumes self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. Furthermore, it is recognized "closed loop" systems are applicable only in instances with very low pressure[2] and may not be suitable to replace many applications of bleeding pneumatic devices. Therefore, these devices are not further discussed in this analysis.

Snap-acting controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from snap-acting devices is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the device's bleed stream. Since actuation emissions serve the device's functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 5.2.2) account for only the continuous flow of emissions (i.e. the bleed rate) and do not include emissions directly resulting from actuation. Snap-acting controllers are assumed to have zero bleed emissions. Most applications (but not all), snap-acting devices serve functionally different purposes than bleed devices. Therefore, snap-acting controllers are not further discussed in this analysis.

In addition, not all pneumatic controllers are gas driven. At sites without electrical service sufficient to power an instrument air compressor, mechanical or electrically powered pneumatic devices can be used. These "non-gas driven" pneumatic controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed "instrument air." Because these devices are not gas driven, they do not directly release natural gas or VOC emissions. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient to power an air compressor. This analysis assumes that natural gas processing plants are the only facilities in the oil and natural gas sector highly likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of gas driven devices.[9] The application of electrical controls is further elaborated in Section 5.3.

5.2 Emissions Data and Information

5.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic devices and the potential options available to reduce these emissions, numerous studies were consulted. Table 5-1 lists these references with an indication of the type of relevant information contained in each study.

5.2.2 Representative Pneumatic Device Emissions

Bleeding pneumatic controllers can be classified into two types based on their emissions rates: (1) high-bleed controllers and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 standard cubic feet per hour (scfh), while low-bleed devices bleed at a rate less than or equal to 6 scfh.[i]

For this analysis, EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, Subpart W of the Greenhouse Gas Reporting rule, as well as obtained updated data from major vendors of pneumatic devices. The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic device model (or model family). All pneumatic devices that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold.

Although by definition, a low-bleed device can emit up to 6 scfh, through this vendor research, it was determined that the typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have emissions from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.[3,ii] While the vendor data provides useful information on specific makes and models, it did not yield sufficient information about the

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[i] The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the Gas Research Institute (GRI) in 1990 titled "Unaccounted for Gas Project Summary Volume." This classification was adopted for the October 1993 Report to Congress titled "Opportunities to Reduce Anthropogenic Methane Emissions in the United States". As described on page 2-16 of the report, "devices with emissions or 'bleed' rates of 0.1 to 0.5 cubic feet per minute are considered to be 'high-bleed' types (PG&E 1990)." This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

[ii] All rates are listed at an assumed supply gas pressure of 20 psig.

Table 5-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Document [3]	EPA	2010	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2009 [4, 5]	EPA	2011	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry [6, 7, 8, 9]	Gas Research Institute / EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry (draft) [10]	EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry [11]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [12]	Western Regional Air Partnership	2005	Regional	X	
Natural Gas STAR Program[1]	EPA	2000-2010		X	X

prevalence of each model type in the population of devices; which is an important factor in developing a representative emission factor. Therefore, for this analysis, EPA determined that best available emissions estimates for pneumatic devices are presented in Table W-1A and W-1B of the Greenhouse Gas Mandatory Reporting Rule for the Oil and Natural Gas Industry (Subpart W). However, for the natural gas processing segment, a more conservative approach was assumed since it has been determined that natural gas processing plants would have sufficient electrical service to upgrade to non-gas driven controls. Therefore, to quantify representative emissions from a bleed-device in the natural gas processing segment, information from Volume 12 of the EPA/GRI report[iii] was used to estimate the methane emissions from a single pneumatic device by type.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic device type in each industry segment and then estimate VOC and hazardous air pollutants (HAP) using a representative gas composition.[13] The specific ratios from the gas composition were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment. Table 5-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment and device type.

5.3 Nationwide Emissions from New Sources

5.3.1 Approach

Nationwide emissions from newly installed natural gas pneumatic devices for a typical year were calculated by estimating the number of pneumatic devices installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 5-2. The number of new pneumatic devices installed for a typical year was determined for each segment of the industry including natural gas production, natural gas processing, natural gas transmission and storage, and oil production. The methodologies that determined the estimated number of new devices installed in a typical year is provided in section 5.3.2 of this chapter.

5.3.2 Population of Devices Installed Annually

In order to estimate the average number of pneumatic devices installed in a typical year, each industry

[iii] Table 4-11. page 56. epa.gov/gasstar/tools/related.html

Table 5-2. Average Bleed Emission Estimates per Pneumatic Device in the Oil and Natural Gas Sector (tons/year)[a]

Industry Segment	High-Bleed			Low-Bleed		
	Methane	VOC	HAP	Methane	VOC	HAP
Natural Gas Production[b]	6.91	1.92	0.073	0.26	0.072	0.003
Natural Gas Transmission and Storage[c]	3.20	0.089	0.003	0.24	0.007	0.0002
Oil Production[d]	6.91	1.92	0.073	0.26	0.072	0.003
Natural Gas Processing[e]	1.00	0.28	0.01	1.00	0.28	0.01

Minor discrepancies may be due to rounding.

a. The conversion factor used in this analysis is 1 thousand cubic feet of methane (Mcf) is equal to 0.0208 tons methane. Minor discrepancies may be due to rounding.
b. Natural Gas Production methane emissions are derived from Table W-1A and W-1B of Subpart W.
c. Natural gas transmission and storage methane emissions are derived from Table W-3 of Subpart W.
d. Oil production methane emissions are derived from Table W-1A and W-1B of Subpart W. It is assumed only continuous bleed devices are used in oil production.
e. Natural gas processing sector methane emissions are derived from Volume 12 of the 1996 GRI report.[9] Emissions from devices in the processing sector were determined based on data available for snap-acting and bleed devices, further distinction between high and low bleed could not be determined based on available data.

segment was analyzed separately using the best data available for each segment. The number of facilities estimated in absence of regulation was undeterminable due to the magnitude of new sources estimated and the lack of sufficient data that could indicate the number of controllers that would be installed in states that may have regulations requiring low bleed controllers, such as in Wyoming and Colorado.

For the natural gas production and oil production segments, the number of new pneumatics installed in a typical year was derived using a multiphase analysis. First, data from the US Greenhouse Gas Inventory: Emission and Sinks 1990-2009 was used to establish the ratio of pneumatic controllers installed per well site on a regional basis. These ratios were then applied to the number of well completions estimated in Chapter 4 for natural gas well completions with hydraulic fracturing, natural gas well completions without hydraulic fracturing and for oil well completions. On average, one pneumatic device was assumed to be installed per well completion for a total of 33,411 pneumatic devices. By applying the estimated 51 percent of bleed devices (versus snap acting controllers), it is estimated that an average of 17,040 bleed-devices would be installed in the production segment in a typical year.

The number of pneumatic controllers installed in the transmission segment was approximated using the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009. The number of new devices installed in a given year was estimated by subtracting the prior year (e.g. 2007) from the given year's total (e.g. 2008). This difference was assumed to be the number of new devices installed in the latter year (e.g. Number of new devices installed during 2008 = Pneumatics in 2008 – Pneumatics in 2007). A 3-year average was calculated based on the number of new devices installed in 2006 through 2008 in order to determine the average number of new devices installed in a typical year.

Once the population counts for the number of pneumatics in each segment were established, this population count was further refined to account for the number of snap-acting devices that would be installed versus a bleed device. This estimate of the percent of snap-acting and bleed devices was based on raw data found in the GRI study, where 51 percent of the pneumatic controllers are bleed devices in the production segment, and 32 percent of the pneumatic controllers are bleed devices in the transmission segment.9 The distinction between the number of high-bleed and low-bleed devices was not estimated because this analysis assumes it is not possible to predict or ensure where low bleeds will be used in the future. Table 5-3 summarizes the estimated number of new devices installed per year.

Table 5-3. Estimated Number of Pneumatic Devices Installed in an Typical Year

Industry Segment	Number of New Devices Estimated for a Typical Year[a]		
	Snap-Acting	Bleed-Devices	Total
Natural Gas and Oil Production[b]	16,371	17,040	33,411
Natural Gas Transmission and Storage[c]	178	84	262

a. National averages of population counts from the Inventory were refined to include the difference in snap-acting and bleed devices based on raw data found in the GRI/EPA study. This is based on the assumption that 51 percent of the pneumatic controllers are bleed devices in the production segment, while 32 percent are bleed devices in the transmission segment.

b. The number of pneumatics was derived from a multiphase analysis. Data from the US Greenhouse Gas Inventory: Emission and Sinks 1990-2009 was used to establish the number of pneumatics per well on a regional basis. These ratios were applied to the number of well completions estimated in Chapter 4 for natural gas wells with hydraulic fracturing, natural gas wells without hydraulic fracturing and for oil wells.

c. The number of pneumatics estimated for the transmission segment was approximated from comparing a 3 year average of new devices installed in 2006 through 2008 in order to establish an average number of pneumatics being installed in this industry segment in a typical year. This analysis was performed using the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009.

For the natural gas processing segment, this analysis assumes that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e. an instrument air system) and any high-bleed devices that remain are safety related. As a result, the number of new pneumatic bleed devices installed at existing natural gas processing plants was estimated as negligible. A new greenfield natural gas processing plant would require multiple control loops. In Chapter 8 of this document, it is estimated that 29 new and existing processing facilities would be subject to the NSPS for equipment leak detection. In order to quantify the impacts of the regulatory options represented in section 5.5 of this Chapter, it is assumed that half of these facilities are new sites that will install an instrument air system in place of multiple control valves. This indicates about 15 instrument air systems will be installed in a representative year.

5.3.3 Emission Estimates

Nationwide baseline emission estimates for pneumatic devices for new sources in a typical year are summarized in Table 5-4 by industry segment and device type. This analysis assumed for the nationwide emission estimate that all bleed-devices have the high-bleed emission rates estimated in Table 5-2 per industry segment since it cannot be predicted which sources would install a low bleed versus a high bleed controller.

5.4 Control Techniques

Although pneumatic devices have relatively small emissions individually, due to the large population of these devices installed on an annual basis, the cumulative VOC emissions for the industry are significant. As a result, several options to reduce emissions have been developed over the years. Table 5-5 provides a summary of these options for reducing emissions from pneumatic devices including: instrument air, non-gas driven controls, and enhanced maintenance.

Given the various control options and applicability issues, the replacement of a high-bleed with a low-bleed device is the most likely scenario for reducing emissions from pneumatic device emissions. This is also supported by States such as Colorado and Wyoming that require the use of low-bleed controllers in place of high-bleed controllers. Therefore, low-bleed devices are further described in the following section, along with estimates of the impacts of their application for a representative device and nationwide basis. Although snap-acting devices have zero bleed emissions, this analysis assumes the

Table 5-4. Nationwide Baseline Emissions from Representative Pneumatic Device Installed in a Typical Year for the Oil and Natural Gas Industry (tons/year)[a]

Industry Segment	Baseline Emissions from Representative New Unit (tpy)			Number of New Bleed Devices Expected Per Year	Nationwide Baseline Emissions from Bleeding Pneumatic (tpy)[b]		
	VOC	Methane	HAP		VOC	Methane	HAP
Oil and Gas Production	1.9213	6.9112	0.0725	17,040	32,739	117,766	1,237
Natural Gas Transmission and Storage	0.09523	3.423	0.003	84	8	288	0.2

Minor discrepancies may be due to rounding.

a. Emissions have been based on the bleed rates for a high-bleed device by industry segment. Minor discrepancies may be due to rounding.
b. To estimate VOC and HAP, weight ratios were developed based on methane emissions per device. The specific ratios used were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment.

Table 5-5. Alternative Control Options for Pneumatic Devices

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Install Low Bleed Device in Place of High Bleed Device	Low-bleed devices provide the same functional control as a high-bleed device, while emitting less continuous bleed emissions.	Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller.	Low-bleed devices are, on average, around $165 more than high bleed versions.
Convert to Instrument Air[14]	Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. For utility purposes such as small pneumatic pumps, gas compressor motor starters, pneumatic tools and sand blasting, air would not need to be dried. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel.	Replacing natural gas with instrument air in pneumatic controls eliminates VOC emissions from bleeding pneumatics. It is most effective at facilities where there are a high concentration of pneumatic control valves and an operator present. Since the systems are powered by electric compressors, they require a constant source of electrical power or a back-up natural gas pneumatic device. These systems can achieve 100 percent reduction in emissions.	A complete cost analysis is provided in Section 5.4.2. System costs are dependent on size of compressor, power supply needs, labor and other equipment.
Mechanical and Solar Powered Systems in place of Bleed device[15]	Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of back-up power or storage to ensure reliability.	Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric powered valves are only reliable with a constant supply of electricity. Overall, these options are applicable in niche areas but can achieve 100 percent reduction in emissions where applicable.	Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems.
Enhanced Maintenance[16]	Instrumentation in poor condition typically bleeds 5 to 10 scf per hour more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear, or loose control tube fittings. This may not impact the operations but does increase emissions.	Enhanced maintenance to repair and maintain pneumatic devices periodically can reduce emissions. Proper methods of maintaining a device are highly variable and could incur significant costs.	Variable based on labor, time, and fuel required to travel to many remote locations.

devices are not always used in the same functional application as bleed devices and are, therefore, not an appropriate form of control for all bleed devices. It is assumed snap-acting, or no-bleed, devices meet the definition of a low-bleed. This concept is further detailed in Section 5.5 of this chapter. Since this analysis has assumed areas with electrical power have already converted applicable pneumatic devices to instrument air systems, instrument air systems are also described for natural gas processing plants only. Given applicability, efficiency and the expected costs of the other options identified in Table 5-5 (i.e. mechanical controls and enhanced maintenance), were not further conducted for this analysis.

5.4.1 Low-Bleed Controllers

5.4.1.1 Emission Reduction Potential

As discussed in the above sections, low-bleed devices provide the same functional control as a high-bleed device, but have lower continuous bleed emissions. As summarized in Table 5-6, it is estimated on average that 6.6 tons of methane and 1.8 tons of VOC will be reduced annually in the production segment from installing a low-bleed device in place of a high-bleed device. In the transmission segment, the average achievable reductions per device are estimated around 3.7 tons and 0.08 tons for methane and VOC, respectively. As noted in section 5.2, a low-bleed controller can emit up to 6 scfh, which is higher than the expected emissions from the typical low-bleed device available on the current market.

5.4.1.1 Effectiveness

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, it is assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the production and transmission and storage industry segments.[1] This corresponds to 13,632 new high-bleed devices in the production segment (out of 17,040) and 67 new high-bleed devices in the transmission and storage segment (out of 84) that can be replaced with a new low-bleed alternative. For high-bleed devices in natural gas processing, this analysis assumed that the replaceable devices have already been replaced with instrument air and the remaining high-bleed devices are safety related for about half of the existing processing plants.

Table 5-6. Estimated Annual Bleed Emission Reductions from Replacing a Representative High-Bleed Pneumatic Device with a Representative Low-Bleed Pneumatic Device

Segment/Device Type	Emissions (tons/year)[a]		
	Methane	VOC	HAP
Oil and Natural Gas Production	6.65	1.85	0.07
Natural Gas Transmission and Storage	2.96	0.082	0.002

Minor discrepancies may be due to rounding.

a. Average emission reductions for each industry segment based on the typical emission flow rates from high-bleed and low-bleed devices as listed in Table 5-2 by industry segment.

Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller. High-bleed pneumatic devices may not be applicable for replacement with low-bleed devices because a process condition may require a fast or precise control response so that it does not stray too far from the desired set point. A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic devices may monitor the suction and discharge pressure and actuate a re-cycle when one or the other is out of the specified target range. Other scenarios for fast and precise control include transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can accommodate control from a low-bleed device, which is slower-acting and less precise.

Safety concerns may be a limitation issue, but only in specific situations because emergency valves are not bleeding controllers since safety is the pre-eminent consideration. Thus, the connection between the bleed rate of a pneumatic device and safety is not a direct one. Pneumatic devices are designed for process control during normal operations and to keep the process in a normal operating state. If an Emergency Shut Down (ESD) or Pressure Relief Valve (PRV) actuation occurs,[iv] the equipment in place for such an event is spring loaded, or otherwise not pneumatically powered. During a safety issue or emergency, it is possible that the pneumatic gas supply will be lost. For this reason, control valves are deliberately selected to either fail open or fail closed, depending on which option is the failsafe.

5.4.1.2 Cost Impacts

As described in Section 5.2.2, costs were based on the vendor research described in Section 5.2 as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices.[1] As Table 5-7 indicates, the average cost for a low bleed pneumatic is $2,553, while the average cost for a high bleed is $2,338.[v] Thus, the incremental cost of installing a low-bleed device instead of a high-bleed device is on the order of $165 per device. In order to analyze cost impacts, the incremental cost to install a low-bleed instead of a high-bleed was

[iv] ESD valves either close or open in an emergency depending on the fail safe configuration. PRVs always open in an emergency.

[v] Costs are estimated in 2008 U.S. Dollars.

Table 5-7. Cost Projections for the Representative Pneumatic Devices[a]

Device	Minimum cost ($)	Maximum cost ($)	Average cost ($)	Low-Bleed Incremental Cost ($)
High-bleed controller	366	7,000	2,388	$165
Low-bleed controller	524	8,852	2,553	

a. Major pneumatic devices vendors were surveyed for costs, emission rates, and any other pertinent information that would give an accurate picture of the present industry.

annualized for a 10 year period using a 7 percent interest rate. This equated to an annualized cost of around $23 per device for both the production and transmission segments.

Monetary savings associated with additional gas captured to the sales line was estimated based on a natural gas value of $4.00 per Mcf.[vi,17] The representative low-bleed device is estimated to emit 6.65 tons, or 319 Mcf, (using the conversion factor of 0.0208 tons methane per 1 Mcf) of methane less than the average high-bleed device per year. Assuming production quality gas is 82.8 percent methane by volume, this equals 385.5 Mcf natural gas recovered per year. Therefore, the value of recovered natural gas from one pneumatic device in the production segment equates to approximately $1,500. Savings were not estimated for the transmission segment because it is assumed the owner of the pneumatic controller generally is not the owner of the natural gas. Table 5-8 provides a summary of low-bleed pneumatic cost effectiveness.

5.4.1.3 Secondary Impacts

Low-bleed pneumatic devices are a replacement option for high-bleed devices that simply bleed less natural gas that would otherwise be emitted in the actuation of pneumatic valves. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the use of low-bleed pneumatic devices.

5.4.2 Instrument Air Systems

5.4.2.1 Process Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following is a description of each component as described in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air:*

- Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank.

[vi] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the value, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings.

Table 5-8. Cost-effectiveness for Low-Bleed Pneumatic Devices versus High Bleed Pneumatics

Segment	Incremental Capital Cost Per Unit ($)[a]	Total Annual Cost Per Unit ($/yr)[b]		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		without savings	with savings	without savings	with savings	without savings	with savings
Oil and Natural Gas Production	165	23.50	-1,519	13	net savings	4	net savings
Natural Gas Transmission and Storage	165	23.50	23.50	286	286	8	8

a. Incremental cost of a low bleed device versus a high bleed device as summarized in Table 5-7.
b. Annualized cost assumes a 7 percent interest rate over a 10 year equipment lifetime.

For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.

- A critical component of the instrument air control system is the power source required to operate the compressor. Since high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of electric power can be difficult to assure. In some instances, solar-powered battery-operated air compressors can be cost effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.

- Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.

- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. The use of instrument air eliminates natural gas emissions from natural gas powered pneumatic controllers. All other parts of a gas pneumatic system will operate the same way with instrument air as they do with natural gas. The conversion of natural gas pneumatic controllers to instrument air systems is applicable to all natural gas facilities with electrical service available.[14]

5.4.2.2 Effectiveness

The use of instrument air eliminates natural gas emissions from the natural gas driven pneumatic devices; however, the system is only applicable in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is a high concentration of pneumatic control valves and the presence of an operator that can ensure the system is properly functioning.[14]

5.4.2.3 Cost Impacts

Instrument air conversion requires additional equipment to properly compress and control the pressured air. The size of the compressor will depend on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas used to run the existing instrumentation – adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is one cubic foot per minute (cfm) of instrument air for each control loop.[14] As the system is powered by electric compressors, the system requires a constant source of electrical power or a back-up pneumatic device. Table 5-9 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and related equipment and the operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator and a storage vessel. It is assumed that in either an instrument air solution or a natural gas pneumatic solution, gas supply piping, control instruments, and valve actuators of the gas pneumatic system are required. The total cost, including installation and labor, of three representative sizes of compressors were evaluated based on assumptions found in the Natural Gas STAR document, "Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air"[14] and summarized in Table 5-10.[vii]

For natural gas processing, the cost-effectiveness of the three representative instrument air system sizes was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because we assume new processing plants will need to provide instrumentation of multiple control loops and size the instrument air system accordingly. We also assume that existing processing plants have already upgraded to instrument air

[vii] Costs have been converted to 2008 US dollars using the Chemical Engineering Cost Index.

Table 5-9. Compressor Power Requirements and Costs for Various Sized Instrument Air Systems[a]

Compressor Power Requirements[b]			Flow Rate	Control Loops
Size of Unit	hp	kW	(cfm)	Loops/Compressor
small	10	13.3	30	15
medium	30	40	125	63
large	75	100	350	175

a. Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*[14]

b. Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50 percent of the year).

Table 5-10 Estimated Capital and Annual Costs of Various Sized Representative Instrument Air Systems

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital[a]	Annualized Capital[b]	Labor Cost	Total Annual Costs[c]	Annualized Cost of Instrument Air System
Small	$3,772	$754	$2,262	$16,972	$2,416	$1,334	$8,674	$11,090
Medium	$18,855	$2,262	$6,787	$73,531	$10,469	$4,333	$26,408	$36,877
Large	$33,183	$4,525	$15,083	$135,750	$19,328	$5,999	$61,187	$80,515

a. Total Capital includes the cost for two compressors, tank, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the Natural Gas Star Lessons Learned document and converted to 2008 dollars from 2006 dollars using the Chemical Engineering Cost Index.

b. The annualized cost was estimated using a 7 percent interest rate and 10 year equipment life.

c. Annual Costs include the cost of electrical power as listed in Table 5-9 and labor.

unless the function has a specific need for a bleeding device, which would most likely be safety related.[9] Table 5-11 summarizes the cost-effectiveness of the three sizes of representative instrument air systems.

5.4.2.4 Secondary Impacts

The secondary impacts from instrument air systems are indirect, variable and dependent on the electrical supply used to power the compressor. No other secondary impacts are expected.

5.5 Regulatory Options

The affected facility definition for pneumatic controllers is defined as a single natural gas pneumatic controller. Therefore, pneumatic controllers would be subject to a New Source Performance Standard (NSPS) at the time of installation. The following Regulatory alternatives were evaluated:

- Regulatory Option 1: Establish an emissions limit equal to 0 scfh.
- Regulatory Option 2: Establish an emissions limit equal to 6 scfh.

5.5.1 Evaluation of Regulatory Options

By establishing an emission limit of 0 scfh, facilities would most likely install instrument air systems to meet the threshold limit. This option is considered cost effective for natural gas processing plants as summarized in Table 5-11. A major assumption of this analysis, however, is that processing plants are constructed at a location with sufficient electrical service to power the instrument air compression system. It is assumed that facilities located outside of the processing plant would not have sufficient electrical service to install an instrument air system. This would significantly increase the cost of the system at these locations, making it not cost effective for these facilities to meet this regulatory option. Therefore, Regulatory Option 1 was accepted for natural gas processing plants and rejected for all other types of facilities.

Regulatory Option 2 would establish an emission limit equal to the maximum emissions allowed for a low-bleed device in the production and transmissions and storage industry segments. This would most likely be met by the use of low-bleed controllers in place of a high-bleed controller, but allows flexibility in the chosen method of meeting the requirement. In the key instances related to pressure control that would disallow the use of a low-bleed device, specific monitoring and recordkeeping criteria

Table 5-11 Cost-effectiveness of Representative Instrument Air Systems in the Natural Gas Processing Segment

System Size	Number of Control Loops	Annual Emissions Reduction[a] (tons/year)			Value of Product Recovered ($/year)[b]	Annualized Cost of System		VOC Cost-effectiveness ($/ton)		Methane Cost-effectiveness ($/ton)	
		VOC	CH_4	HAP		without savings	with savings	without savings	with savings	without savings	with savings
Small	15	4.18	15	0.16	3,484	11,090	7,606	2,656	1,822	738	506
Medium	63	17.5	63	0.66	14,632	36,877	22,245	2,103	1,269	585	353
Large	175	48.7	175	1.84	40,644	80,515	39,871	1,653	819	460	228

Minor discrepancies may be due to rounding.

a. Based on the emissions mitigated from the entire system, which includes multiple control loops.
b. Value of recovered product assumes natural gas processing is 82.8 percent methane by volume. A natural gas price of $4 per Mcf was assumed.

would be required to ensure the device function dictates the precision of a high bleed device. Therefore, Regulatory Option 2 was accepted for locations outside of natural gas processing plants.

5.5.2 Nationwide Impacts of Regulatory Options

Table 5-12 summarizes the costs impacts of the selected regulatory options by industry segment. Regulatory Option 1 for the natural gas processing segment is estimated to affect 15 new processing plants with nationwide annual costs discounting savings of $166,000. When savings are realized the net annual cost is reduced to around $114,000. Regulatory Option 2 has nationwide annual costs of $320,000 for the production segment and around $1,500 in the natural gas transmission and storage segment. When annual savings are realized in the production segment there is a net savings of $20.7 million in nationwide annual costs.

Table 5-12 Nationwide Cost and Emission Reduction Impacts for Selected Regulatory Options by Industry Segment

Industry Segment	Number of Sources subject to NSPS*	Capital Cost Per Device/IAS ($)**	Annual Costs ($/year)		Nationwide Emission Reductions (tpy)†			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs ($/year)		
			without savings	with savings	VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 1 (emission threshold equal to 0 scfh)														
Natural Gas Processing	15	16,972	11,090	7,606	63	225	2	2,656	1,822	738	506	254,576	166,351	114,094
Regulatory Option 2 (emission threshold equal to 6 scfh)														
Oil and Natural Gas Production	13,632	165	23	(1,519)	25,210	90,685	952	13	net savings	4	net savings	2,249,221	320,071	(20,699,918)
Natural Gas Transmission and Storage	67	165	23	23	6	212	0.2	262	262	7	7	11,039	1,539	1,539

Minor discrepancies may be due to rounding.

a. The number of sources subject to NSPS for the natural gas processing and the natural gas transmission and storage segments represent the number of new devices expected per year reduced by 20 percent. This is consistent with the assumption that 80 percent of high bleed devices can be replaced with a low bleed device. It is assumed all new sources would be installed as a high bleed for these segments. For the natural gas processing segment the number of new sources represents the number of Instrument Air Systems (IAS) that is expected to be installed, with each IAS expected to power 15 control loops (or replace 15 pneumatic devices).
b. The capital cost for regulatory option 2 is equal to the incremental cost of a low bleed device versus a new high bleed device. The capital cost of the IAS is based on the small IAS as summarized in Table 5-10.
c. Nationwide emission reductions vary based on average expected emission rates of bleed devices typically used in each segment industry segment as summarized in Tables 5-2.

5.6 References

1 U.S. Environmental Protection Agency. Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004

2 Memorandum to Bruce Moore from Denise Grubert. Meeting Minutes from EPA Meeting with the American Petroleum Institute. October 2011

3 U.S. Environmental Protection Agency. Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry: Background Technical Support Document. Climate Change Division. Washington, DC. November 2010.

4 U.S Environmental Protection Agency. Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2008. Washington, DC.

5 U.S Environmental Protection Agency. Methodology for Estimating CH4 and CO2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2008. Washington, DC.

6 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080b. June 1996.

7 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080c. June 1996.

8 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080e. June 1996.

9 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080k. June 1996.

10 Radian International LLC, Methane Emissions from the U.S. Petroleum Industry, draft report for the U.S. Environmental Protection Agency, June 14, 1996.

11 ICF Consulting. Estimates of Methane Emissions from the U.S. Oil Industry. Prepared for the U.S. Environmental Protection Agency. 1999.

12 ENVIRON International Corporation. Oil and Gas Emission Inventories for the Western States. Prepared for Western Governors' Association. December 27, 2005.

13 Memorandum to Bruce Moore from Heather Brown. Gas Composition Methodology. July 2011

14 U.S. Environmental Protection Agency. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004

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16 CETAC WEST. Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments. Prepared for the Canadian Association of Petroleum Producers. May 2008.

17 U.S. Energy Information Administration. Annual U.S. Natural Gas Wellhead Price. Energy Information Administration. Natural Gas Navigator. Retrieved online on 12 Dec 2010 at <http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>

6.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and gas industry as prime movers are reciprocating and centrifugal compressors. This chapter discusses the air pollutant emissions from these compressors and provides emission estimates for reducing emission from these types of compressors. In addition, nationwide emissions estimates from new sources are estimated. Options for controlling pollutant emissions from these compressors are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for both reciprocating and centrifugal compressors.

6.1 Process Description

6.1.1 Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time,during operation of the compressor, the rings become worn and the packing system will need to be replaced to prevent excessive leaking from the compression cylinder.

6.1.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and absorbs some compressed natural gas which is released to the atmosphere during the seal oil recirculation process. Alternatively, dry seals can be used to replace the wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic groves and springs. The opposing forcescreate a thin gap of high pressure gas between the rings through which little gas can leak. The rings do not wear or need lubrication because they are not in contact with each other. Therefore, operation and maintenance costs are lower for dry seals in comparison to wet seals.

6.2 Emissions Data and Emission Factors

6.2.1 Summary of Major Studies and Emissions Factors

There are a few studies that have been conducted that provide leak estimates from reciprocating and centrifugal compressors. These studies are provided in Table 6-1, along with the type of information contained in the study.

6.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The methodology for estimating emission from reciprocating compressor rod packing was to use the methane emission factors referenced in the EPA/GRI study[1] and use the methane to pollutant ratios developed in the gas composition memorandum.[2] The emission factors in the EPA/GRI document were expressed in thousand standard cubic feet per cylinder (Mscf/cyl), and were multiplied by the average number of cylinder per reciprocating compressor at each oil and gas industry segment. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the methane emission factors is presented in Table 6-2. Once the methane emissions were calculated, ratios were used to estimate volatile organic compounds (VOC) and hazardous air pollutants (HAP). The specific ratios that were used for this analysis were 0.278 pounds VOC per pound of methane and 0.105 pounds HAP per pound of methane for the production and processing segments, and 0.0277 pounds VOC per pound of methane and 0.0008 pounds HAP per pound of methane for the transmission and storage segments. A summary of the reciprocating compressor emissions are presented in Table 6-3.

The compressor emission factors for wet seals and dry seals are based on data used in the GHG inventory. The wet seals methane emission factor was calculated based on a sampling of 48 wet seal centrifugal compressors. The dry seal methane emission factor was based on data collected by the

Table 6-1. Major Studies Reviewed for Consideration Of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Information	Emissions Information	Control Information
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008[1]	EPA	2010	Nationwide	X	
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Document[2]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry[3]	Gas Research Institute/EPA	1996	Nationwide	X	
Natural Gas STAR Program[4,5]	EPA	1993-2010	Nationwide	X	X

Table 6-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors

Oil and Gas Industry Segment	Reciprocating Compressors			Centrifugal Compressors	
	Methane Emission Factor (scf/hr-cylinder)	Average Number of Cylinders	Pressurized Factor (% of hour/year Compressor Pressurized)	Wet Seal Methane Emission Factor (scf/minute)	Dry Seals Methane Emission Factor (scf/minute)
Production (Well Pads)	0.271[a]	4	100%	N/A[f]	N/A[f]
Gathering & Boosting	25.9[b]	3.3	79.1%	N/A[f]	N/A[f]
Processing	57[c]	2.5	89.7%	47.7[g]	6[g]
Transmission	57[d]	3.3	79.1%	47.7[g]	6[g]
Storage	51[e]	4.5	67.5%	47.7[g]	6[g]

a. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-8.
b. Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites.* (Draft): 2006.
c. EPA/GRI. (1996). Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks. Table 4-14.
d. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-17.
e. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-24.
f. The 1996 EPA/GRI Study Volume 11[3], does not report any centrifugal compressors in the production or gathering/boosting sectors, therefore no emission factor data were published for those two sectors.
g. U.S Environmental Protection Agency. Methodology for Estimating CH4 and CO2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks1990-2009. Washington, DC. April 2011. Annex 3. Page A-153.

Table 6-3.Baseline Emission Estimates for Reciprocating and Centrifugal Compressors

Industry Segment/ Compressor Type	Baseline Emission Estimates (tons/year)		
	Methane	VOC	HAP
Reciprocating Compressors			
Production (Well Pads)	0.198	0.0549	0.00207
Gathering & Boosting	12.3	3.42	0.129
Processing	23.3	6.48	0.244
Transmission	27.1	0.751	0.0223
Storage	28.2	0.782	0.0232
Centrifugal Compressors (Wet seals)			
Processing	228	20.5	0.736
Transmission	126	3.50	0.104
Storage	126	3.50	0.104
Centrifugal Compressors (Dry seals)			
Processing	28.6	2.58	0.0926
Transmission	15.9	0.440	0.0131
Storage	15.9	0.440	0.0131

Natural Gas STAR Program. The methane emissions were converted to VOC and HAP emissions using the same gas composition ratios that were used for reciprocating engines.[4] A summary of the emission factors are presented in Table 6-2 and the individual compressor emission are shown in Table 6-3 for each of the oil and gas industry segments.

6.3 Nationwide Emissions from New Sources

6.3.1 Overview of Approach

The number of new affected facilities in each of the oil and gas sectors was estimated using data from the U.S. Greenhouse Gas Inventory,[5,6] with some exceptions. This basis was used whenever the total number of existing facilities was explicitly estimated as part of the Inventory, so that the difference between two years can be calculated to represent the number of new facilities. The Inventory was not used to estimate the new number of reciprocating compressor facilities in gas production, since more recent information is available in the comments received to subpart W of the mandatory reporting rule. Similarly, the Inventory was not used to estimate the new number of reciprocating compressor facilities in gas gathering, since more recent information is available in comments received as comments to subpart W of the mandatory reporting rule. For both gas production and gas gathering, information received as comments to subpart W of the mandatory reporting rule was combined with additional EPA estimates and assumptions to develop the estimates for the number of new affected facilities.

Nationwide emission estimates for new sources were then determined by multiplying the number of new sources for each oil and gas segment by the expected emissions per compressor using the emission data in Table 6-3. A summary of the number of new reciprocating and centrifugal compressors for each of the oil and gas segments is presented in Table 6-4.

6.3.2 Activity Data for Reciprocating Compressors

6.3.2.1 Wellhead Reciprocating Compressors

The number of wellhead reciprocating compressors was estimated using data from industry comments on Subpart W of the Greenhouse Gas Mandatory Reporting Rule.[7] The 2010 U.S. GHG Inventory reciprocating compressor activity data was not considered in the analysis because it does not distinguish between wellhead and gathering and boosting compressors. Therefore, using data submitted to EPA during the subpart W comment period from nine basins supplied by the El Paso Corporation,[8] the

Table 6-4.Approximate Number of New Sources in the Oil and Gas Industry in 2008

<table>
<tr><th>Industry Segment</th><th>Number of New Reciprocating Compressors</th><th>Number of New Centrifugal Compressors</th></tr>
<tr><td>Wellheads</td><td>6,000</td><td>0</td></tr>
<tr><td>Gathering and Boosting</td><td>210</td><td>0</td></tr>
<tr><td>Processing</td><td>209</td><td>16</td></tr>
<tr><td>Transmission</td><td>20</td><td rowspan="2">14</td></tr>
<tr><td>Storage</td><td>4</td></tr>
</table>

average number of new wellhead compressors per new well was calculated using the 315 well head compressors provided in the El Paso comments and 3,606 wells estimated in the Final Subpart W onshore production threshold analysis. This produced an average of 0.087 compressors per wellhead. The average wellhead compressors per well was multiplied by the total well completions (oil and gas) determined from the HPDI® database[9] between 2007 and 2008, which came to 68,000 new well completions. Using this methodology, the estimated number of new reciprocating compressors at production pads was calculated to be 6,000 for 2008. A summary of the number of new reciprocating compressors located at well pads is presented in Table 6-4.

6.3.2.2 Gathering and Boosting Reciprocating Compressors

The number of gathering & boosting reciprocating compressors was also estimated using data from industry comments on Subpart W. DCP Midstream stated on page 3 of its 2010 Subpart W comments that it operates 48 natural gas processing plants and treaters and 700 gathering system compressor stations. Using this data, there were an average of 14.583 gathering and boosting compressor stations per processing plant. The number of new gathering and boosting compressors was determined by taking the average difference between the number of processing plants for each year in the 2010 U.S Inventory, which references the total processing plants in the Oil and Gas Journal. This was done for each year up to 2008. An average was taken of only the years with an increase in processing plants, up to 2008. The resulting average was multiplied by the 14.583 ratio of gathering and boosting compressor stations to processing plants and the 1.5 gathering and boosting compressors per station yielding 210 new source gathering and boosting compressor stations and is shown in Table 6-4.

6.3.2.3 Processing Reciprocating Compressors

The number of new processing reciprocating compressors at processing facilities was estimated by averaging the increase of reciprocating compressors at processing plants in the greenhouse gas inventory data for 2007, 2008, and 2009.[10,11] The estimated number of existing reciprocating compressors in the processing segment was 4,458, 4,781, and 4,876 for the years 2007, 2008, and 2009 respectively. This calculated to be 323 new reciprocating compressors between 2007 and 2008, and 95 new reciprocating compressors between 2008 and 2009. The average difference was calculated to be 209 reciprocating compressors and was used to estimate the number of new sources in Table 6-4.

6.3.2.4 Transmission and Storage Reciprocating Compressors

The number of new transmission and storage reciprocating compressors was estimated using the differences in the greenhouse gas inventory[12,13] data for 2007, 2008, and 2009 and calculating an average of those differences. The estimated number of existing reciprocating compressors at transmission stations was 7,158, 7,028, and 7,197 for the years 2007, 2008, and 2009 respectively. This calculated to be -130 new reciprocating compressors between 2007 and 2008, and 169 new reciprocating compressors between 2008and 2009. The average difference was calculated to be 20 reciprocating compressors and was used to estimate the number of new sources at transmission stations. The number of existing reciprocating compressors at storage stations was 1,144, 1,178, and 1,152 for the years 2007, 2008, and 2009 respectively. This calculated to be 34 new reciprocating compressors between 2007 and 2008, and -26 new reciprocating compressors between 2008and 2009. The average difference was calculated to be 4 reciprocating compressors and was used to estimate the number of new sources at storage stations in Table 6-4.

6.3.3 Activity Data for Centrifugal Compressors

The number of new centrifugal compressors in 2008 for the processing and transmission/storage segments was determined by taking the average difference between the centrifugal compressor activity data for each year in the 2008 U.S. Inventory . For example, the number of compressors in 1992 was subtracted from the number of compressors in 1993 to determine the number of new centrifugal compressors in 1993. This was done for each year up to 2008. An average was taken of only the years with an increase in centrifugal compressors, up to 2008, to determine the number of new centrifugal compressors in 2008. The result was 16 and 14 new centrifugal compressors in the processing and transmission segments respectively. A summary of the estimates for new centrifugal compressor is presented in Table 6-4.

6.3.4 Emission Estimates

Nationwide baseline emission estimates for new reciprocating and centrifugal compressors are summarized in Table 6-5 by industry segment.

Table 6-5.Nationwide Baseline Emissions for New Reciprocating and Centrifugal Compressors

Industry Segment/ Compressor Type	Nationwide baseline Emissions (tons/year)		
	Methane	**VOC**	**HAP**
Reciprocating Compressors			
Production (Well Pads)	1,186	330	12.4
Gathering & Boosting	2,587	719	27.1
Processing	4,871	1,354	51.0
Transmission	529	14.6	0.435
Storage	113	3.13	0.0929
Centrifugal Compressors			
Processing	3,640	329	11.8
Transmission/Storage	1,768	48.9	1.45

6.4 Control Techniques

6.4.1 Potential Control Techniques

The potential control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. This includesreplacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod.

The replacement of the rod packing is a maintenance task performed on reciprocating compressors to reduce the leakage of natural gas past the piston rod. Over time the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings reduces methane and VOC emissions. Therefore, this control technique was determined to be an appropriate optionfor reciprocating compressors.

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.[14] Rods wear "out-of-round" or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. This analysis assumes operators will choose, at their discretion, when to replace the rod and hence, does not consider this control technique to be a practical control option for reciprocating compressors. A summary of these techniques are presented in the following sections.

Potential control options to reduce emissions from centrifugal compressors include control techniques that limit the leaking of natural gas across the rotating shaft, or capture and destruction of the emissions using a flare. A summary of these techniques are presented in the following sections.

A control technique for limiting or reducing the emission from the rotating shaft of a centrifugal compressor is a mechanical dry seal system. This control technique uses rings to prevent the escape of natural gas across the rotating shaft. This control technique was determined to be a viable option for reducing emission from centrifugal compressors.

For centrifugal compressors equipped with wet seals, a flare was considered to be a reasonable option for reducing emissions from centrifugal compressors. Centrifugal compressors require seals around the rotating shaft to prevent natural gas from escaping where the shaft exits the compressor casing. "Beam" type compressors have two seals, one on each end of the compressor, while "over-hung" compressors have a seal on only the "inboard" (motor end) side. These seals use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. The seal also includes "O-ring" rubber seals, which prevent leakage around the stationary rings. The oil barrier allows some gas to escape from the seal, but considerably more gas is entrained and absorbed in the oil under the high pressures at the "inboard" (compressor side) seal oil/gas interface, thus contaminating the seal oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated back to the seal. As a control measure, the recovered gas would then be sent to a flare or other combustion device.

6.4.2 Reciprocating Compressor Rod Packing Replacement

6.4.2.1 Description

Reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the "nose gasket" around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed gas will escape. Periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod.

6.4.2.2 Effectiveness

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The potential emission reductions were calculated by comparing the average rod packing emissionswith the average emissions from newly installed and worn-in rod packing. Since the estimate for newly installed rod packing was intended for larger processing and transmission compressors, this analysis uses the estimate to calculate reductions from only gathering and boosting compressors and not wellhead compressor which are known to be smaller. The calculation for gathering and boosting reductions is shown in Equation 1.

$$R_{WP}^{G\&B} = \frac{Comp_{New}^{G\&B}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6} \qquad \textbf{Equation 1}$$

where,

$R_{WP}^{G\&B}$ = Potential methane emission reductions from gathering and boosting compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{G\&B}$ = Number of new gathering and boosting compressors;
$E_{G\&B}$ = Methane emission factor for gathering and boosting compressors inTable 6-2, in cubic feet per hour per cylinder;
E_{New}=Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[15] for this analysis;
C = Average number of cylinders for gathering and boosting compressors in Table 6-2;
O = Percent of time during the calendar year the average gathering and boosting compressor is in the operating and standby pressurized modes, 79.1%;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

For wellhead reciprocating compressors, this analysis calculates a percentage reduction using the transmission emission factor from the 1996 EPA/GRI report and the minimum emissions rate from a newly installed rod packing to determine methane emission reductions. The calculation for wellhead compressor reductions is shown in Equation 2 below.

$$R_{Well} = \frac{Comp_{New}^{Well}\left(E_{Well}\right) \times C \times O \times 8760}{10^6}\left(\frac{E_{Trans} - E_{New}}{E_{Trans}}\right) \qquad \textbf{Equation 2}$$

where,

R_{Well} = Potential methane emission reductions from wellhead compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{Well}$ = Number of new wellhead compressors;
E_{Well} = Methane emission factor for wellhead compressors from Table 6-2, cubic feet per hour per cylinder;
C = Average number of cylinders for wellhead compressors in Table 6-2;
O = Percent of time during the calendar year the average gathering and boosting compressor is in the operating and standby pressurized modes, 100%;

E_{Trans} = Methane emissions factor for transmission compressors from Table 6-2 in cubic feet per hour per cylinder;
E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[16] for this analysis;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

The emission reductions for the processing, transmission, and storage segments were calculated by multiplying the number of new reciprocating compressors in each segment by the difference between the average rod packing emission factors in Table 6-2 by the average emission factor from newly installed rod packing. This calculation, shown in the Equation 3 below, was performed for each of the natural gas processing, transmission, and storage/LNG sectors.

$$R_{PTS} = \frac{Comp_{New}^{PTS}\left(E_{G\&B} - E_{New}\right)\times C \times O \times 8760}{10^6} \qquad \textbf{\textit{Equation 3}}$$

where,

R_{PTS} = Potential methane emission reductions from processing, transmission, or storage compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{PTS}$ = Number of new processing, transmission, or storage compressors;
$E_{G\&B}$ = Methane emission factor for processing, transmission, or storage compressors in Table 6-2, in cubic feet per hour per cylinder;
E_{New}=Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[17] for this analysis;
C = Average number of cylinders for processing, transmission, or storage compressors in Table 6-2;
O = Percent of time during the calendar year the average processing, transmission, or storage compressor is in the operating and standby pressurized modes, 89.7%, 79.1%, 67.5% respectively;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

A summary of the potential emission reductions for reciprocating rod packing replacement for each of the oil and gas segments is shown in Table 6-6. The emissions of VOC and HAP were calculated using the methane emission reductions calculated above the gas composition[18] for each of the segments. Reciprocating compressors in the processing sector were assumed to be used to compress production gas.

Table 6-6.Estimated Annual Reciprocating Compressor Emission Reductions from Replacing Rod Packing

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)			Nationwide Emission Reductions (tons/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Production (Well Pads)	6,000	0.158	0.0439	0.00165	947	263	9.91
Gathering & Boosting	210	6.84	1.90	0.0717	1,437	400	15.1
Processing	375	18.6	5.18	0.195	3,892	1,082	40.8
Transmission	199	21.7	0.600	0.0178	423	11.7	0.348
Storage	9	21.8	0.604	0.0179	87.3	2.42	0.0718

6.4.2.3 Cost Impacts

Costs for the replacement of reciprocating compressor rod packing were obtained from a Natural Gas Star Lessons Learned document[19] which estimated the cost to replace the packing rings to be $1,620 per cylinder. It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring becausethe rod packingplacement is based on number of hours that the compressor operates. The replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program. [20] The cost impacts arebased on the replacement of the rod packing 26,000 hours that the reciprocating compressor operates in the pressurized mode. The number of hours used for the cost impacts was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized for all of the new sources. This weighted hours, on average, per year the reciprocating compressor is pressurized was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. This calculates to an average of 3 years for production compressors, 3.8 years for gathering and boosting compressors, 3.3 years for processing compressors, 3.8 years for transmission compressors, and 4.4 years for storage compressors using the operating factors in Table 6-2. The calculated years were assumed to be the equipment life of the compressor rod packing and were used to calculate the capital recovery factor for each of the segments. Assuming an interest rate of 7 percent, the capital recovery factors were calculated to be 0.3848, 0.3122, 0.3490, 0.3122, and 0.2720 for the production, gathering and boosting, processing, transmission, and storage sectors, respectively. The capital costs were calculated using the average rod packing cost of $1,620 and the average number of cylinders per segment in Table 6-2. The annual costs were calculated using the capital cost and the capital recovery factors. A summary of the capital and annual costs for each of the oil and gas segments is shown in Table 6-7.

Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement was estimated using a natural gas price of $4.00 per Mcf.[21] This cost was used to calculate theannual cost with gas savings using the methane emission reductions in Table 6-6. The annual cost with savings is shown in Table 6-7 for each of the oil and gas segments. The cost effectiveness for the reciprocating rod packing replacement option is presented in Table 6-7. There is no gas savings cost benefits for transmission and storage facilities, because they do not own the natural gas that is

Table 6-7. Cost Effectiveness for Reciprocating Compressor Rod Packing Replacement

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor ($/compressor-year)		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		Without savings	With savings	Without savings	With savings	Without savings	With savings
Production	$6,480	$2,493	$2,457	$56,847	$56,013	$15,802	$15,570
Gathering & Boosting	$5,346	$1,669	$83	$877	$43	$244	$12
Processing	$4,050	$1,413	-$2,903	$273	-$561	$76	-$156
Transmission	$5,346	$1,669	N/A	$2,782	N/A	$77	N/A
Storage	$7,290	$2,276	N/A	$3,766	N/A	$104	N/A

compressed at their compressor stations.

6.4.2.4 Secondary Impacts

The reciprocating compressor rod packing replacement is an option that prevents the escape of natural gas from the piston rod. No wastes should be created, no wastewater generated, and no electricity maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring becausethe rod packing

6.4.3 Centrifugal Compressor Dry Seals

6.4.3.1 Description

Centrifugal compressor dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This gas is pumped between the rings by grooves in the rotating ring. The opposing force of high-pressure gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little gas can leak. While the compressor is operating, the rings are not in contact with each other, and therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.

Dry seals substantially reduce methane emissions. At the same time, they significantly reduce operating costs and enhance compressor efficiency. Economic and environmental benefits of dry seals include:

- Gas Leak Rates. During normal operation, dry seals leak at a rate of 6scfmmethane per compressor.[22] While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is re-circulated is usually vented to the atmosphere, bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.[23,24]
- Mechanically Simpler. Dry seal systems do not require additional oil circulation components and treatment facilities.

- Reduced Power Consumption. Because dry seals have no accessory oil circulation pumps and systems, they avoid “parasitic” equipment power losses. Wet seal systems require 50 to 100 kW per hour, while dry seal systems need about 5 kW of power per hour.
- Improved Reliability. The highest percentage of downtime for a compressor using wet seals is due to seal system problems. Dry seals have fewer ancillary components, which translates into higher overall reliability and less compressor downtime.
- Lower Maintenance. Dry seal systems have lower maintenance costs than wet seals because they do not have moving parts associated with oil circulation (e.g., pumps, control valves, relief valves, and the seal oil cost itself).
- Elimination of Oil Leakage from Wet Seals. Substituting dry seals for wet seals eliminates seal oil leakage into the pipeline, thus avoiding contamination of the gas and degradation of the pipeline.

Centrifugal compressors were found in the processing and transmission sectors based on information in the greenhouse gas inventory.[25] Therefore, it was assumed that new compressors would be located in these sectors only.

6.4.3.2 Effectiveness

The control effectiveness of the dry seals was calculated by subtracting the dry seal emissions from a centrifugal compressor equipped with wet seals. The centrifugal compressor emission factors in Table 6-2 were used in combination with an operating factor of 43.6 percent for processing centrifugal compressors and 24.2 percent for transmission centrifugal compressors. The operating factors are used to account for the percent of time in a year that a compressor is in the operating mode. The operating factors for the processing and transmission sectors are based on data in the EPA/GRI study.[26] The wet seals emission factor is an average of 48 different wet seal centrifugal compressors. The dry seal emission factor is based on information from the Natural Gas STAR Program.[27] A summary of the emission reduction from the replacement of wet seals with dry seals is shown in Table 6-8.

6.4.3.3 Cost Impacts

The price difference between a brand new dry seal and brand new wet seal centrifugal compressor is insignificant relative to the cost for the entire compressor. General Electric (GE) stated that a natural gas transmission pipeline centrifugal compressor with dry seals cost between $50,000 and $100,000 more than the same centrifugal compressor with wet seals. However, this price difference is only about 1 to 3

Table 6-8. Estimated Annual Centrifugal Compressor Emission Reductions from Replacing Wet Seals with Dry Seals

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (ton/compressor-year)			Nationwide Emission Reductions (ton/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Transmission/Storage	16	199	18.0	0.643	3,183	287	10.3
Storage	14	110	3.06	0.0908	1,546	42.8	1.27

percent of the total cost of the compressor. The price of a brand new natural gas transmission pipeline centrifugal compressor between 3,000 and 5,000 horsepower runs between \$2 million to \$5 million depending on the number of stages, desired pressure ratio, and gas throughput. The larger the compressor, the less significant the price difference is between dry seals and wet seals. This analysis assumes the additional capital cost for a dry seal compressor is \$75,000. The annual cost was calculatedas the capital recovery of this capital cost assuming a 10-year equipment life and 7 percent interest which came to \$10,678 per compressor. The Natural Gas STAR Program estimated that the operation and maintenance savings from the installation of dry seals is \$88,300 in comparison to wet seals. Monetary savings associated with the amount of gas saved with the replacement of wet seals with dry seals for centrifugal compressors was estimated using a natural gas price of \$4.00 per Mcf.[28] This cost was used to calculate the annual cost with gas savings using the methane emission reductions in Table 6-8. A summary of the capital and annual costs for dry seals is presented in Table 6-9. The methane and VOC cost effectiveness for the dry seal option is also shown in Table 6-9. There is no gas savings cost benefits for transmission and storage facilities, because it is assumed the owners of the compressor station may not own the natural gas that is compressed at the station.

6.4.3.4 Secondary Impacts

Dry seals for centrifugal compressors are an option that prevents the escape of natural gas across the rotating compressor shaft. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the installation of dry seals on centrifugal compressors.

6.4.4 Centrifugal Compressor Wet Seals with a Flare

6.4.4.1 Description

Another control option used to reduce pollutant emissions from centrifugal compressors equipped withwet seals is to route the emissions to a combustion device or capture the emissions and route them to afuel system. A wet seal system uses oil that is circulated under high pressure between three rings aroundthe compressor shaft, forming a barrier against the compressed gas. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. Compressed gas becomes absorbed and entrained in the fluid barrier and is removed using a heater, flash tank, or other degassing technique so that the oil can be recirculated back to the wet seal. The removed gas is either

Table 6-9. Cost Effectiveness for Centrifugal Compressor Dry Seals

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor ($/compressor-yr)		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		without savings	with O&M and gas savings	without savings	with O&M and gas savings	without savings	with O&M and gas savings
Processing	$75,000	$10,678	-$123,730	$595	-$6,892	$54	-$622
Transmission/Storage	$75,000	$10,678	-$77,622	$3,495	-$25,405	$97	-$703

combusted or released to the atmosphere. The control technique investigated in this section is the use of wet seals with the removed gas sent to an enclosed flare.

6.4.4.2 Effectiveness

Flares have been used in the oil and gas industry to combust gas streams that have VOC and HAP. A flare typically achieves 95 percent reduction of these compounds when operated according to the manufacturer instructions. For this analysis, it was assumed that the entrained gas from the seal oil that is removed in the degassing process would be directed to a flare that achieves 95 percent reduction of methane, VOC, and HAP. The wet seal emissions in Table 6-5 were used along with the control efficiency to calculate the emissions reductions from this option. A summary of the emission reductions is presented in Table 6-10.

6.4.4.3 Cost Impacts

The capital and annual cost of the enclosed flare was calculated using the methodology in the EPA Control Cost Manual.[29] The heat content of the gas stream was calculated using information from the gas composition memorandum.[30] A summary of the capital and annual costs for wet seals routed to a flare is presented in Table 6-11. The methane and VOC cost effectiveness for the wet seals routed to a flare option is also shown in Table 6-12. There is no cost saving estimated for this option because the recovered gas is combusted.

6.4.4.4 Secondary Impacts

There are secondary impacts with the option to use wet seals with a flare. The combustion of the recovered gas creates secondary emissions of hydrocarbons, nitrogen oxide (NO_X), carbon dioxide (CO_2), and carbon monoxide (CO) emissions. A summary of the estimated secondary emission are presented in Table 6-11. No other wastes should be created or wastewater generated.

6.5 Regulatory Options

The affected facility definition for a reciprocating compressor is defined as a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of thedriveshaft. A centrifugal compressor is defined as a piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers. Therefore these types of compressor would be

Table 6-10. Estimated Annual Centrifugal Compressor Emission Reductions from Wet Seals Routed to a Flare

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)			Nationwide Emission Reductions (tons/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Processing	16	216	19.5	0.699	3,283	296	10.6
Transmission/Storage	14	120	3.32	0.0986	1,596	44.2	1.31

Table 6-11. Secondary Impacts from Wet Seals Equipped with a Flare

Industry Segment	Secondary Impacts from Wet Seals Equipped with a Flare (tons/year)				
	Total Hydrocarbons	**Carbon Monoxide**	**Carbon Dioxide**	**Nitrogen Oxides**	**Particulate Matter**
Processing	0.0289	0.0205	7.33	0.00377	Negligible
Transmission/Storage	0.00960	0.00889	3.18	0.00163	Negligible

Table 6-12. Cost Effectiveness for Centrifugal Compressor Wet Seals Routed to a Flare

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor ($/compressor-year)		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		without savings	with gas savings	without savings	with gas savings	without savings	with gas savings
Processing	$67,918	$103,371	N/A	$5,299	N/A	$478	N/A
Transmission/Storage	$67,918	$103,371	N/A	$31,133	N/A	$862	N/A

subject to a New Performance Standard (NSPS) at the time of installation. The following Regulatory options were evaluated:

- Regulatory Option 1: Require replacement of the reciprocating compressor rod packing based on26,000 hours of operation while the compressor is pressurized.
- Regulatory Option 2: Require all centrifugal compressors to be equipped with dry seals.
- Regulatory Option 3: Require centrifugal compressors equipped with a wet seal to route the recovered gas emissions to a combustion device.

6.5.1 Evaluation of Regulatory Options

The first regulatory option for replacement of the reciprocating compressor rod packing based on the number of hours that the compressor operates in the pressurized mode was described in Section 6.4.1. The VOC cost effectiveness from $56,847 for reciprocating compressors located at production pads to $273 for reciprocating compressors located at processing plants. The VOC cost effectiveness for the gathering and boosting, transmission, and storage segments were $877, $2,782, and 3,766 respectively. Based on these cost effectiveness values, Regulatory Option 1 was accepted for the processing, gathering and boosting, transmission, and storage segments and rejected for the production segment.

The second regulatory option would require all centrifugal compressors to be equipped with dry seals. As presented in Section 6.4.2, dry seals are effective at reducing emissions from the rotating shaft of a centrifugal compressor. Dry seals also reduce operation and maintenance costs in comparison to wet seals. In addition, a vendor reported in 2003 that 90 percent of new compressors that were sold by the company were equipped with dry seals. Another vendor confirmed in 2010 that the rate at which new compressor sales have dry seals is still 90 percent; thus, it was assumed that from 2003 onward, 90 percent of new compressors are equipped with dry seals. The VOC cost effectiveness of dry seals was calculated to be $595 for centrifugal compressors located at processing plants, and $3,495 for centrifugal compressors located at transmission or storage facilities. Therefore, Regulatory Option 2 was accepted as a regulatory option for centrifugal compressors located at processing, transmission, or storage facilities.

The third regulatory option would allow the use of wet seals if the recovered gas emissions were routed to a flare. Centrifugal compressors with wet seals are commonly used in high pressure applications over 3,000 pounds per square inch (psi). None of the applications in the oil and gas industry operate at these pressures. Therefore, it does not appear that any facilities would be required to operate a centrifugal compressor with wet seals. The VOC control effectiveness for the processing and transmission/storage segments were $5,299 and $31,133 respectively. Therefore, Regulatory Option 3 was rejected due to the high VOC cost effectiveness.

6.5.2 Nationwide Impacts of Regulatory Options

Tables 6-13 and 6-14 summarize the impacts of the selected regulatory options by industry segment. Regulatory Option 1 is estimated to affect 210 reciprocating compressors at gathering and boosting stations, 209 reciprocating compressors at processing plants, 20 reciprocating compressors at transmission facilities, and 4 reciprocating compressors at underground storage facilities. A summary of the capital and annual costs and emission reductions for this option is presented in Table 6-13.

Regulatory Option 2 is expected to affect 16 centrifugal compressors in the processing segment and 14 centrifugal compressors in the transmission and storage segments. A summary of the capital and annual costs and emission reductions for this option is presented in Table 6-14.

Table 6-13. Nationwide Cost Impacts for Regulatory Option 1

Oil & Gas Segment	Number of New Sources Per Year	Nationwide Emission Reductions (tons/year)			Total Nationwide Costs		
		VOC	Methane	HAP	Capital Cost ($)	Annual Cost without savings ($/yr)	Annual Cost with savings ($/yr)
Gathering & Boosting	210	400	1,437	15.1	$1,122,660	$350,503	$17,337
Processing	209	1,082	3,892	40.8	$846,450	$295,397	-$606,763
Transmission	20	11.7	423	0.348	$104,247	$32,547	$32,547
Storage	4	2.42	87.3	0.0718	$29,160	$9,104	$9,104

Table 6-14. Nationwide Cost Impacts for Regulatory Option 2

Oil & Gas Segment	Number of New Sources Per Year	Nationwide Emission Reductions[1] (tons/year)			Total Nationwide Costs[a]		
		VOC	Methane	HAP	Capital Cost ($)	Annual Cost w/o Savings ($/year)	Annual Cost w/ Savings ($/year)
Production (Well Pads)	0	0	0	0	0	0	0
Gathering & Boosting	0	0	0	0	0	0	0
Processing	16	118	422	4.42	$100,196	$14,266	-$120,144
Transmission/Storage	14	3.24	117	0.0962	$50,098	$7,133	-$37,017

a. The nationwide emission reduction and nationwide costs are based on the emission reductions and costs for 2 centrifugal compressors with wet seals located a processing facility and 1 centrifugal compressor equipped with wet seal located at a transmission or storage facility.

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7.0 STORAGE VESSELS

Storage vessels, or storage tanks, are sources of air emissions in the oil and natural gas sector. This chapter provides a description of the types of storage vessels present in the oil and gas sector, and provides emission estimates for a typical storage vessel as well as nationwide emission estimates. Control techniques employed to reduce emissions from storage vessels are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter provides a discussion of considerations used in developing regulatory alternatives for storage vessels.

7.1 Process Description

Storage vessels in the oil and natural gas sector are used to hold a variety of liquids, including crude oil, condensates, produced water, etc. Underground crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons (as well as water) are removed through as series of high-pressure and low-pressure separators. Crude oil under high pressure conditions is passed through either a two phase separator (where the associated gas is removed and any oil and water remain together) or a three phase separator (where the associated gas is removed and the oil and water are also separated). At the separator, low pressure gas is physically separated from the high pressure oil. The remaining low pressure oil is then directedto a storage vessel where it is stored for a period of time before being shipped off-site. The remaining hydrocarbons in the oil are released from the oil as vapors in the storage vessels. Storage vessels are typically installed with similar or identical vessels in a group, referred to in the industry as a tank battery.

Emissions of the remaining hydrocarbons from storage vessels are a function of working, breathing (or standing), and flash losses. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage vesselfrom a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage stage. Temperature of the liquid may also influence the amount of flash emissions.

The volume of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the overall throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vesselwill affect the volume of flashed gases coming out of the oil.

The composition of the vapors from storage vessels varies, and the largest component is methane, but also includes ethane, butane, propane, and hazardous air pollutants (HAP) such as benzene, toluene, ethylbenzene, xylene (collectively referred to as BTEX), and n-hexane.

7.2 Emissions Data

7.2.1 Summary of Major Studies and Emissions

Given the potentially significant emissions from storage vessels, there have been numerous studies conducted to estimate these emissions. Many of these studies were consulted to evaluate the emissions and emission reduction options for emissions from storage vessels. Table 7-1 presents a summary of these studies, along with an indication of the type of information available in each study.

7.2.2 Representative Storage Vessel Emissions

Due to the variability in the sizes and throughputs, model tank batteries were developed to represent the ranges of sizes and population distribution of storage vessels located attank batteries throughout the sector. Model tank batteries were not intended to represent any single facility, but rather a range of facilities with similar characteristics that may be impacted by standards. Model tank batteries were developed for condensate tank batteries and crude oil tank batteries. Average VOC emissions were then developed and applied to the model tank batteries.

7.2.2.1 Model Condensate Tank Batteries

During the development of the national emissions standards for HAP (NESHAP) for oil and natural gas production facilities (40 CFR part 63, subpart HH), model plants were developed to represent condensate tank batteries across the industry.[1]For this current analysis, the most recent inventory data available was the 2008 U.S. Greenhouse Gas Emissions Inventory.[2,3] Therefore, 2008 was chosen to represent the base year for this impacts analysis.To estimate the current condensate battery population and distribution across the model plants, the number of tanks represented by the model plants was scaled

Table 7-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emission Figures	Control Information
VOC Emissions from Oil and Condensate Storage Tanks[4]	Texas Environmental Research Consortium	2009	Regional	X	X
Lessons Learned from Natural Gas STAR Partners:Installing Vapor Recovery Units on Crude Oil Storage Tanks[5]	EPA	2003	National		X
Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation – Final Report[6]	Texas Commission on Environmental Quality	2009	Regional	X	
Initial Economics Impact Analysis for Proposed State Implementation Plan Revisions to the Air Quality Control Commission's Regulation Number [7]	Colorado	2008	n/a		X
E&P TANKS[8]	American Petroleum Institute		National	X	
Inventory of U.S. Greenhouse Gas Emissions and Sinks[2,3]	EPA	2008 and 2009	National	X	

from 1992 (the year for which that the model plants were developed under the NESHAP) to 2008 for this analysis. Based on this approach, it was estimated that there were a total of 59,286 existing condensate tanks in 2008. Condensate throughput data from the U.S. Greenhouse Gas Emissions Inventory was used to scale up from 1992 the condensate tank populations for each model condensate tank battery under the assumption that an increase in condensate production would be accompanied by a proportional increase in number of condensate tanks. The inventory data indicate that condensate production increased from a level of 106 million barrels per year (MMbbl/yr) in 1992to 124 MMbbl/yr in 2008.This increase in condensate production was then distributed across the model condensate tank batteriesin the same proportion as was done for the NESHAP. The model condensate tank batteries are presented in Table 7-2.

7.2.2.2 Model Crude Oil Tank Batteries

According to the Natural Gas STAR program,[5] there were 573,000 crude oil storage tanksin 2003. According to the U.S. Greenhouse Gas Emissions Inventory, crude oil production decreased from 1,464 MMbbl/yr in 2003 to 1,326 MMbbl/yr (a decrease of approximately 9.4 percent) in 2008. Therefore, it was assumed that the number of crude oil tanks in 2008 were approximately 90.6 percent of the number of tanks identified in 2003. Therefore, for this analysis it was assumed that there were 519,161 crude oil storage tanks in 2008. During the development of the NESHAP, model crude oil tank batteries were not developed and a crude oil tank population was not estimated. Therefore, it was assumed that the percentage distribution of crude oil storage tanks across the four model crude oil tank battery classifications was the same as for condensate tank batteries.Table 7-3 presents the model crude oil tank batteries.

7.2.2.3 VOC Emissions from Condensate and Crude Oil Storage Vessels

Once the modelcondensate and crude oil tank battery distributionswere developed, VOC emissions from a representative storage vessel were estimated. Emissions from storage vessels vary considerably depending on many factors, including, but not limited to, throughput, API gravity, Reid vapor pressure, separator pressure, etc. The American Petroleum Institute (API) has developed a software program called E&P TANKS which contains a dataset of more than 100 storage vessels from across the country.[8] A summary of the information contained in the dataset, as well as the output from the E&P TANKS program, is presented in Appendix A of this document. According to industry representatives, this

Table 7-2. Model Condensate Tank Batteries

	Model Condensate Tank Battery			
Parameter	**E**	**F**	**G**	**H**
Condensate throughput (bbl/day)[a]	15	100	1,000	5,000
Condensate throughput (bbl/yr) [a]	5,475	36,500	365,000	1,825,000
Number of fixed-roof product storage vessels [a]				
210 barrel capacity	4	2		
500 barrel capacity		2	2	
1,000 barrel capacity			2	4
Estimated tank battery population (1992)[a]	12,000	500	100	70
Estimated tank battery population (2008) [b]	14,038	585	117	82
Total number of storage vessels (2008) [b]	56,151	2,340	468	328
Percent of number of storage vessels in model condensate tank battery	94.7%	3.95%	0.789%	0.552%
Percent of throughput per model condensate tank battery[a]	26%	7%	15%	51%
Total tank battery condensate throughput (MMbbl/yr)[c]	32.8	9.11	18.2	63.8
Condensate throughput per model condensate battery (bbl/day)	6.41	42.7	427	2,135
Condensate throughput per storage vessel (bbl/day)	1.60	10.7	106.8	534

Minor discrepancies may be due to rounding.

a. Developed for NESHAP (Reference 1).

b. Population of tank batteries for 2008 determined based on condensate throughput increase from 106 MMbbl/yr in 1992 to 124 MMbbl/yr in 2008 (References2,3).

c. 2008 condensate production rate of 124 MMbbl/yr distributed across model tank batteries using same relative ratio as developed for NESHAP (Reference 1).

Table 7-3. Model Crude Oil Tank Batteries

	Model Crude Oil Tank Battery			
Parameter	**E**	**F**	**G**	**H**
Percent of number of condensate storage vessels in model size range[a]	94.7%	3.95%	0.789%	0.552%
Number of storage vessels[b]	491,707	20,488	4,098	2,868
Percent of throughput across condensate tank batteries	26%	7%	15%	51%
Crude oil throughput per model plant category (MMbbl/yr)	351	97.5	195	683
Crude oil throughput per storage vessel (bbl/day)	1.96	13.0	130	652

Minor discrepancies may be due to rounding.

a. Same relative percent of storage vessel population developed for model condensate tank batteries.Refer to Table 7-2.
b. Calculated by applying the percent of number of condensate storage vessels in model size range to total number of crude oil storage vessels (519,161 crude oil storage vessels estimated for 2008) (Reference 5).
c. Same relative percent of throughput developed for model condensate tank batteries.Refer to Table 7-2.

dataset in combination with the output of the E&P TANKS program is representative of the various VOC emissions from storage vessels across the country.[9]

The more than 100 storage vesselsprovided with the E&P TANKS program, which had varying characteristics, were modeled with a constant throughput (based on the assumption that emissions would increase in proportion with throughput) and the relationship of these different characteristics and emissionswas studied. While many of the characteristics impacted emissions, a correlation was found to exist between API gravity and emissions. The average API gravity for all storage vessels in the data set was approximately 40 degrees. Therefore, we selected an API gravity of 40 degrees as a parameter to distinguish between lower emitting storage vessels and higher emitting storage vessels.[i] While the liquid type was not specified for the storage vessels modeled in the study, it was assumed that condensate storage vessels would have higher emissions than crude oil storage vessels. Therefore, based on this study using the E&P TANKS program, it was assumed for this analysis that liquids with API gravity equal to or greater than 40 degrees should be classified as condensate and liquids with API gravity less than 40 degrees should be classified as crude oil.

The VOC emissions from all storage vessels in the analysis are presented in Appendix A.Table 7-4 presents a summary of the average VOC emissions from all storage vessels as well as the average VOC emissions from the storage vessels identified as being condensate storage vessels and those identified as being crude oil storage vessels. As shown in Table 7-4, the storage vessels were modeled at a constant throughput of 500 bpd.[ii]An average emission factor was developed for each type of liquid. The average of condensate storage vessel VOC emissions was modeled to be 1,046 tons/year or 11.5 lb VOC/bbl and the average of crude oil storage vessel VOC emissions was modeled to be 107 tons/year or 1.18 lb VOC/bbl. These emission factors were then applied to each of the two sets of model storage vessels in Tables 7-2 and 7-4 to develop the VOC emissions from the model tank batteries. These are presented in Table 7-5.

[i] The range of VOC emissions within the 95 percent confidence interval for storage vessels with an API gravity greater than 40 degrees was from 667 tons/year to 1425 tons/year. The range for API gravity less than 40 degrees was 76 tons/year to 138.
[ii] This throughput was originally chosen for this analysis to be equal to the 500 bbl/day throughput cutoff in subpart HH. While not part of the analysis described in this document, one of the original objectives of the E&P TANKS analysis was to assess the level of emissions associated with a storage vessel with a throughput below this cutoff. Due to the assumption that emissions increase and decrease in proportion with throughput, it was decided that using a constant throughput of 500 bbl/day would still provide the information necessary to determine VOC emissions from model condensate and crude oil storage vessels for this document.

Table 7-4. Summary of Data from E&P TANKS Modeling

Parameter[a]		Average of Dataset	Average of Storage Vessels with API Gravity > 40 degrees	Average of Storage Vessels with API Gravity ≤ 40 degrees
Throughput Rate (bbl)		500	500	500
API Gravity		40.6	52.8	30.6
VOC	Emissions (tons/year)	531	1046	107
	Emission factor (lb/bbl)	5.8	11.5	1.18

a. Information from analysis of E&P Tanks dataset, refer to Appendix A.

Table 7-5. Model Storage Vessel VOC Emissions

Parameter	Model Tank Battery			
	E	F	G	H
Model Condensate Tank Batteries				
Condensate throughput per storage vessel (bbl/day)	1.60	10.7	107	534
VOC Emissions (tons/year)[b]	3.35	22.3	223	1117
Model Crude Oil Tank Batteries				
Crude Oil throughput per storage vessel (bbl/day)[c]	2.0	13	130	652
VOC Emissions (tons/year)[d]	0.4	2.80	28	140

a. Condensate throughput per storage vessel from table 7-2.

b. Calculated using the VOC emission factor for condensate storage vessels of 11.5 lb VOC/bbl condensate.

c. Crude oil throughput per storage vessel from table 7-3.

d. Calculated using the VOC emission factor for crude oil storage vessels of 1.18 lb VOC/bbl crude oil.

7.3 Nationwide Baseline Emissions from New or Modified Sources

7.3.1 Overview of Approach

The first step in this analysis is to estimate nationwide emissions in absence of a federal rulemaking, referred to as the nationwide baseline emissions estimate. In order to develop the baseline emissions estimate, the number of new storage vessels expected in a typical year was calculated and then multiplied by the expected uncontrolled emissions per storage vessels presented in Table 7-5. In addition, to ensure no emission reduction credit was attributed to new sources that would already be required to be controlled under State regulations, it was necessary to account for the number of storage vessels already subject to State regulations as detailed below.

7.3.2 Number of New Storage Vessels Expected to be Constructed or Reconstructed

The number of new storage vessels expected to be constructed was determined for the year 2015 (the year of analysis for the regulatory impacts). To do this, it was assumed that the number of new or modified storage vessels would increase in proportion with increases in production. The Energy Information Administration (EIA), published crude oil production rates up to the year 2011.[10] Therefore, using the forecast function in Microsoft Excel® , crude oil production was predicted for the year 2015.[iii] From 2009 to 2015,[iv] the expected growth of crude oil production was projected to be 8.25 percent (from 5.36 bpd to 5.80 bpd). Applying this expected growth to the number of existing storage vessels results in an estimate of 4,890 new or modified condensate storage vessels and 42,811 new or modified crude oil storage vessels. The number of new or modified condensate and crude oil storage vessels expected to be constructed or reconstructed is presented in Table 7-6.

7.3.3 Level of Controlled Sources in Absence of Federal Regulation

As stated previously, to determine the impact of a regulation, it was first necessary to determine the current level of emissions from the sources being evaluated, or baseline emissions. To more accurately estimate baseline emissions for this analysis, and to ensure no emission reduction credit was attributed

[iii] The crude oil production values published by the EIA include leased condensate. Therefore, the increase in crude oil production was assumed to be valid for both crude oil and condensate tanks for the purpose of this analysis.
[iv] For the purposes of estimating growth, the crude oil production rate in the year 2008 was considered an outlier for production and therefore was not used in this analysis.

Table 7-6. Nationwide Baseline Emissions for Storage Vessels

	Model Tank Battery				
	E	**F**	**G**	**H**	**Total**
Model Condensate Tank Batteries					
Total number of storage vessels (2008)	56,151	2,340	468	328	59,286
Total projected number of new or modified storage vessels (2015) [a]	4,630	193	39	27	4,889
Number of uncontrolled storage vessels in absence of federal regulation[b]	1,688	70	14	10	1,782
Uncontrolled VOC Emissions from storage vessel at model tank battery[c]	3.35	22.3	223	1,117	1,366
Total Nationwide Uncontrolled VOC Emissions	5,657	1,572	3,143	11,001	21,373
Model Crude Oil Tank Batteries					
Total number of storage vessels (2008)	491,707	20,488	4,098	2,868	519,161
Total projected number of new or modified storage vessels (2015) [a]	40,548	1,689	338	237	42,812
Number of uncontrolled storage vessels in absence of federal regulation[b]	14,782	616	123	86	15,607
Uncontrolled VOC Emissions from storage vessel at model tank battery[c]	0.4	2.80	28	140	171
Total Nationwide Uncontrolled VOC Emissions	6,200	1,722	3,444	12,055	23,421

Minor discrepancies may be due to rounding

a. Calculated by applying the expected 8.25 percent industry growth to the number of storage vessels in 2008.
b. Calculated by applying the estimated 36 percent of storage vessels that are uncontrolled in the absence of a Federal Regulation to the total projected number of new or modified storage vessels in 2015.
c. VOC Emissions from individual storage vessel at model tank battery, see Table 7-5.

for sources already being controlled, it was necessary to determine which storage vessels were already being controlled. To do this, the 2005 National Emissions Inventory (NEI) was used.Storage vessels in the oil and natural gas sector were identified under the review of the maximum achievable control technology (MACT) standards.[11] There were 5,412 storage vessels identified in the NEI, and of these, 1,973 (or 36 percent) were identified as being uncontrolled. Therefore, this percent of storage vessels that would not require controls under State regulations was applied to the number of new or modified storage vessels results in an estimate of 1,782 new or modified condensate storage vessels and 15,607 new or modified crude oil storage vessels.These are also presented in Table 7-6.

7.3.4 Nationwide Emission Estimates for New or Modified Storage Vessels

Nationwide emissions estimates are presented in Table 7-6 for condensate storage vessels and crude oil storage vessels. Model storage vessel emissions were multiplied by the number of expected new or modified storage vessels that would be uncontrolled in the absence of a federal regulation.As shown in Table 7-6, the baseline nationwide emissions are estimated to be 21,373 tons/year for condensate storage vessels and 23,421 tons/year for crude oil storage vessels.

7.4 Control Techniques

7.4.1 Potential Control Techniques

In analyzing controls for storage vessels, we reviewed control techniques identified in the Natural Gas STAR program and state regulations. We identified two ways of controlling storage vessel emissions, both of which can reduce VOC emissions by 95 percent. One option would be to install a vapor recovery unit (VRU) and recover all the vapors from the storage vessels. The other option would be to route the emissions from the storage vessels to a combustor. These control technologies are described below along with their effectiveness as they apply to storage vessels in the oil and gas sector, cost impacts associated with the installation and operation of these control technologies, and any secondary impacts associated with their use.

7.4.2 Vapor Recovery Units

7.4.2.1 Description

Typically, with a VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator, or suction scrubber, to collect any condensed liquids, which are typically recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system. Vapors are then either sent to the pipeline for sale or used as on-site fuel.[5]

7.4.2.2 Effectiveness

Vapor recovery units have been shown to reduce VOC emissions from storage vessels by approximately 95 percent.***Error! Bookmark not defined.***A VRU recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold.If natural gas is recovered, it can be sold as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU also does not have secondary air impacts, as described below. However, a VRU cannot be used in all instances. Some conditions that affect the feasibility of VRU are: availability of electrical service sufficient to power the compressor; fluctuations in vapor loading caused by surges in throughput and flash emissions from the storage vessel; potential for drawing air into condensate storage vessels causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

7.4.2.3 Cost Impacts

Cost data for a VRU was obtained from an Initial Economic Impact Analysis (EIA) prepared for proposed state-only revisions to a Colorado regulation.Cost information contained in the EIA was assumed to be giving in 2007 dollars.[7]Therefore costs were escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4).[12] According to the EIA, the purchased equipment cost of a VRU was estimated to be $85,423 (escalated to 2008 dollars from $75,000 in 2007 dollars). Total capital investment, including freight and design and installation was estimated to be $98,186. These cost data are presented in Table 7-7. Total annual costs were estimated to be $18,983/year.

7.4.2.4 Secondary Impacts

A VRU is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., nitrogen oxides, particulate matter, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the use of a VRU.

Table 7-7. Total Capital Investment and Total Annual Cost of a Vapor Recovery Unit

Cost Item[a]	Capital Costs ($)	Non-Recurring, One-time Costs ($)	Total Capital Investment ($)[b]	O&M Costs ($)	Savings due to Fuel Sales ($/yr)	Annualized Total Cost ($/yr)[c]
VRU	$78,000					
Freight and Design		$1,500				
VRU Installation		$10,154				
Maintenance				$8,553		
Recovered natural gas					($1,063)	
Subtotal Costs (2007)	$78,000	$11,654		$8,553	($1,063)	
Subtotal Costs (2008)[d]	$85,423	$12,763	$98,186	$9,367	($1,164)	
Annualized costs (using 7% interest, 15 year equipment life)	$9,379	$1,401		n/a	n/a	$18,983

Minor discrepancies may be due to rounding

a. Assume cost data provided is for the year 2007. Reference 7.
b. Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.
c. Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.
d. Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 12.

7.4.3 Combustors

7.4.3.1 Description and Effectiveness

Combustors are also used to control emissions from condensate and crude oil storage vessels.The type of combustor used is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.[13] Combustors are used to control VOC in many industrial settings, since thecombustorcan normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[14] For this analysis, the types of combustors installed for the oil and gas sector are assumed to achieve 95 percent efficiency.[7] Combustors do not have the same operational issues as VRUs, however secondary impacts are associated with combustors as discussed below.

7.4.3.2 Cost Impacts

Cost data for a combustor was also obtained from the Initial EIA prepared for proposed state-only revisions to the Colorado regulation.[7] As performed for the VRU, costs were escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4).[12] According to the EIA, the purchased equipment cost of a combustor, including an auto igniter and surveillance system was estimated to be $23,699 (escalated to 2008 dollars from $21,640 in 2007 dollars). Total capital investment, including freight and design and installation was estimated to be $32,301. These cost data are presented in Table 7-8. Total annual costs were estimated to be $8,909/year.

7.4.3.3 Secondary Impacts

Combustion and partial combustion of many pollutants also create secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide, and smoke/particulates. Reliable data for emission factors from combustors on condensate and crude oil storage vessels are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing 80 percent propylene and 20 percent propane.[13] These emissions factors, however, are thebest indication for secondary pollutants from combustors currently available. The secondary emissionsper storage vessel are provided in Table 7-9.

Table 7-8. Total Capital Investment and Total Annual Cost of a Combustor

Cost Item[a]	Capital Costs ($)	Non-Recurring, One-time Costs ($)	Total Capital Investment ($)[b]	O&M Costs ($)	Annualized Total Cost ($/yr) [c]
Combustor	$16,540				
Freight and Design		$1,500			
Combustor Installation		$6,354			
Auto Igniter	$1,500				
Surveillance System[d]	$3,600				
Pilot Fuel				$1,897	
Maintenance				$2,000	
Data Management				$1,000	
Subtotal Costs (2007)	$21,640	$7,854		$4,897	
Subtotal Costs (2008) [e]	$23,699	$8,601	$32,301	$5,363	
Annualized costs (using 7% interest, 15 year equipment life)	$2,602	$944		n/a	$8,909

Minor discrepancies may be due to rounding

a. Assume cost data provided is for the year 2007. Reference 7.
b. Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.
c. Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.
d. Surveillance system identifies when pilot is not lit and attempt to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.
e. Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 12.

Table 7-9. Secondary Impacts for Combustors used to Control Condensate and Crude Oil Storage Vessels

Pollutant	Emission Factor	Units	Emissions per Storage Vessel (tons/year)[a]
THC	0.14	lb/MMBtu	0.0061
CO	0.37	lb/MMBtu	0.0160
CO_2	60	Kg/MMBtu[b]	5.62
NO_X	0.068	lb/MMBtu	2.95E-03
PM	40	µg/l (used lightly smoking flares due to criteria that flares should not have visible emissions i.e. should not smoke)	5.51E-05

a. Converted using average saturated gross heating value of the storage vessel vapor (1,968 Btu/scf) and an average vapor flow rate of 44.07 Mcf per storage vessel. See Appendix A.
b. CO_2 emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

7.5 Regulatory Options and Nationwide Impacts of Regulatory Options

7.5.1 Consideration of Regulatory Options for Condensate and Crude Oil Storage Vessels

The VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (i.e., its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility and temperature of the liquid.Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric pressure. Therefore, in order to determine the most cost effective means of controlling the storage vessels, a cutoff was evaluated to limit the applicability of the standards to these storage vessels. Rather than require a cutoff in terms of emissions that would require a facility to conduct an emissions test on their storage vessel, a throughput cutoff was evaluated. It was assumed that facilities would have storage vessel throughput data readily available. Therefore, we evaluated the costs of controlling storage vessels with varying throughputs to determine which throughput level would provide the most cost effective control option.

The standard would require an emission reduction of 95 percent, which, as discussed above, could be achieved with a VRU or a combustor. A combustoris an option for tank batteries because of the operational issues associated with a VRU as discussed above.However the use of a VRU is preferable to a combustorbecause a combustordestroys, rather than recycles, valuable resources and there are secondary impacts associated with the use of a combustor. Therefore, the cost impacts associated a VRU installed for the control of storage vessels were evaluated.

To conduct this evaluation, emission factor data from a study prepared for the Texas Environmental Research Consortium[15] was used to represent emissions from the different throughputs being evaluated. For condensate storage vessels, an emission factor of 33.3 lb VOC/bbl was used and for crude oil storage vessels, an emission factor of 1.6 lb VOC/bbl was used.Using the throughput for each control option, an equivalent emissions limit was determined.Table 7-10 presents the following regulatory options considered for condensate storage vessels:

- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 0.5 bbl/day (equivalent emissions of 3.0 tons/year);

Table 7-10. Options for Throughput Cutoffs for Condensate Storage Vessels

Regulatory Option	Throughput Cutoff (bbl/day)	Equivalent Emissions Cutoff (tons/year) [a]	Emission Reduction (tons/year) [b]	Annual Costs for VRU ($/yr) [c]	Cost Effectiveness ($/ton)	Number of impacted units[d]
1	0.5	3.0	2.89	$18,983	$6,576	1782
2	1	6.1	5.77	$18,983	$3,288	94
3	2	12.2	11.55	$18,983	$1,644	94
4	5	30.4	28.87	$18,983	$658	24

Minor discrepancies may be due to rounding

a. Emissions calculated using emission factor of 33.3 lb VOC/bbl condensate and the throughput associated with each option.
b. Calculated using 95 percent reduction
c. Refer to Table 7-7 for VRU Annual Costs.
d. Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-6) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its throughput and emissions were greater than the cutoffs for the option.

- Regulatory Option 2: Control condensate storage vessels with a throughput greater than 1 bbl/day (equivalent emissions of 6 tons/year);
- Regulatory Option 3: Control condensate storage vessels with a throughput greater than 2 bbl/day (equivalent emissions of 12 tons/year);
- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 5.0 bbl/day (equivalent emissions of 30 tons/year);

As shown in Table 7-10, Regulatory Option 1 is not cost effective for condensate storage vessels with a throughput of 0.5 bbl/day.Therefore Regulatory Option 1 is rejected.Since the cost effectiveness associated with Regulatory Option 2 is acceptable ($3,288/ton), this option was selected. As shown in Table 7-5, Model Condensate Storage Vessel Categories F, G, and H have throughputs greater than 1 bbl/day and emissions greater than 6 tons/year. Therefore, for the purposes of determining impacts, the populations of new and modified condensate storage vessels associated with categories F, G, and H are assumed to be required to reduce their emissions by 95 percent, a total of 94 new or modified condensate storage vessels.

A similar evaluation was performed for crude oil vessels and is presented in Table 7-11 for the following regulatory options:

- Regulatory Option 1: Control crude oil storage vessels with a throughput greater than 1 bbl/day (equivalent emissions of 0.3 tons/year);
- Regulatory Option 2: Control condensate storage vessels with a throughput greater than 5 bbl/day (equivalent emissions of 1.5 tons/year);
- Regulatory Option 3: Control condensate storage vessels with a throughput greater than 20 bbl/day (equivalent emissions of 6 tons/year);
- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 50 bbl/day (equivalent emissions of 15 tons/year);

As shown in Table 7-11, Regulatory Options 1 and 2 are not cost effective crude oil storage vessels with a throughput of 1 and 5 bbl/day, respectively. Therefore Regulatory Options 1 and 2 are rejected.Since the cost effectiveness associated with Regulatory Option 3 is acceptable ($3,422/ton), this option was selected. As shown in Table 7-5, Model Crude Oil Storage Vessel CategoriesG and H have throughputs greater than 20 bbl/day and emissions greater than 6 tons/year. Therefore, for the purposes of determining impacts, the populations of new and modified crude oil storage vessels associated with categories G

Table 7-11. Options for Throughput Cutoffs for Crude Oil Storage Vessels

Regulatory Option	Throughput Cutoff (bbl/day)	Equivalent Emissions Cutoff (tons/year) [a]	Emission Reduction (tons/year) [b]	Annual Costs for VRU ($/yr) [c]	Cost Effectiveness ($/ton)	Number of impacted units[d]
1	1	0.3	0.28	$18,983	$68,432	15607
2	5	1.5	1.4	$18,983	$13,686	825
3	20	5.8	5.55	$18,983	$3,422	209
4	50	14.6	13.87	$18,983	$1,369	209

Minor discrepancies may be due to rounding

a. Emissions calculated using emission factor of 1.6 lb VOC/bbl condensate and the throughput associated with each option.
b. Calculated using 95 percent reduction
c. Refer to Table 7-7 for VRU Annual Costs.
d. Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-6) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its throughput and emissions were greater than the cutoffs for the option.

and H are assumed to be required to reduce their emissions by 95 percent, a total of 209 new or modified condensate storage vessels.

7.5.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Option 2 for condensate storage vessels and Regulatory Option 3 for crude oil storage vessels which were selected as viable options for setting standards for storage vessels.In addition, combined impacts for a typical storage vessel are presented.

7.5.3 Primary Environmental Impacts of Regulatory Options

Regulatory Option2 (condensate storage vessels) and 3 (crude oil storage vessels) were selected as options for setting standards for storage vessels as follows:

- Regulatory Option 2 (Condensate Storage Vessels): Reduce emissions from condensate storage vessels with an average throughput greater than 1 bbl/day.

- Regulatory Option 3 (Crude Oil Storage Vessels): Reduce emissions from crude oil storage vessels with an average throughput greater than 20 bbl/day.

The number of storage vessels that would be subject to the regulatory options listed above are presented in Tables7-10 and 7-11. It was estimated that there would be 94 new or modified condensate storage vessels not otherwise subject to State regulationsand impacted by Regulatory Option 2 (condensate storage vessels).As shown in Table 7-11, 209 new or modified crude oil storage vessels not otherwise subject to State regulations would be impacted by Regulatory Option 3 (crude oil storage tanks).

Table 7-12 presents the nationwide emission reduction estimates for each regulatory option. Emissions reductions were estimated by applying 95 percent control efficiency to the VOC emissions presented in Table 7-6 for each storage vessel in the model condensate and crude oil tank batteries and multiplying by the number of impacted storage vessels. For Regulatory Option 2 (condensate storage vessels), the total nationwide VOC emission reduction was estimated to be 15,061 tons/year and 14,710 tons/year for Regulatory Option 3 (crude oil storage vessels).

Table 7-12. Nationwide Impacts of Regulatory Options

Model Tank Battery	Number of Sources subject to Regulatory Option[a]	VOC Emissions for a Typical Storage Vessel (tons/year)	Capital Cost forTypical Storage Vessel[b] ($)	Annual Cost for a Typical Storage Vessel[b] ($/yr)		Nationwide Emission Reductions (tons/year)[c]		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
				without savings	with savings	VOC	Methane[d]	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 2: Condensate Storage Vessels														
F	70	22.3	65,243	14,528	13,946	1,483	325	685	658	3129	3004	4.57	1.02	0.98
G	14	223	65,243	14,528	13,946	2,966	649	68	66	313	301	0.913	0.203	0.195
H	10	1117	65,243	14,528	13,946	10,612	2,322	14	13	62.6	60.1	0.652	0.145	0.139
Total for Regulatory Option 2						**15,061**	**3,296**					**6.14**	**1.37**	**1.31**
Regulatory Option 3: Crude Oil Storage Vessels														
G	123	28	65,243	14,528	13,946	3,272	716	546	524	2496	2396	8.02	1.79	1.71
H	86	140	65,243	14,528	13,946	11,438	2,503	109	104	499	479	5.61	1.25	1.20
Total for Regulatory Option 3						**14,710**	**3,219**					**13.6**	**3.04**	**2.91**
Combined Impacts[e]														
Typical Storage Vessel	**304**	**103**	**65,243**	**14,528**	**13,946**	**29,746**	**6,490**	**149**	**143**	**680**	**652**	**19.8**	**4.41**	**4.24**

Minor discrepancies may be due to rounding

a. Number of storage vessels in each model tank battery (refer to Table 7-6) determined to be subject to the regulatory option as outlined in Table 7-10.

b. It was assumed for the purposes of estimating nationwide impacts that 50 percent of facilities would install a combustor and 50 percent a VRU.This accounts for the operational difficulties of using a VRU. Capital and Annual Costs determined using the average of costs presented in Tables 7-7 and 7-8.

c. Nationwide emission reductions calculated by applying a 95 percent emissions reduction to the VOC emissions for a typical storage vessel multiplied by the number of sources subject to the regulatory option.

d. Methane Reductions calculated by applying the average Methane to VOC factor from the E&P Tanks Study (see Appendix A).Methane:VOC = 0.219

e. For purposes of evaluating NSPS impact, impacts were determined for an average storage vessel by calculating total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels to obtain the average VOC emissions per storage vessel.

7.5.4 Cost Impacts

Cost impacts of the individual control techniques (VRU and combustors) were presented in Section 7.4. For both regulatory options, it was assumed that 50 percent of facilities would install a combustor and 50 percent a VRU. This accounts for the operational difficulties of using a VRU. Therefore, the average capital cost of control for each storage vessel was estimated to be $65,243 (the average of the total capital investment for a VRU of $98,186 and $32,301 for a combustor from Tables 7-7 and 7-8, respectively). Similarly, the average annual cost for a typical storage vessel was estimated to be $14,528/yr (average of the total annual cost for a VRU of $20,147/yr and $8,909/yr for a combustor from Tables 7-7 and 7-8, respectively) without including any cost savings due to fuel sales and $13,946/yr (average of the total annual cost for a VRU of $18,983/yr and $8,909/yr for a combustorfrom Tables 7-7 and 7-8, respectively) including cost savings.

Nationwide capital and annual costs were calculated by applying the number of storage vessels subject to the regulatory option. As shown in Table 7-12, the nationwide capital cost of Regulatory Option 2 (condensate storage vessels) was estimated to be $6.14 million and for RegulatoryOption 3 (crude oil storage vessels) nationwide capital cost was estimated to be $13.6 million.Total annual costs without fuel savings were estimated to be $1.37 million/yr for Regulatory Option 2 (condensate storage vessels) and $3.04 million/yr for Regulatory Option 3 (crude oil storage vessels). Total annual costs with fuel savings were estimated to be $1.31 million/yr for Regulatory Option 2 (condensate storage vessels) and $2.91 million/yr for Regulatory Option 3 (crude oil storage vessels).

For purposes of evaluating the impact of a federal standard, impacts were determined for an average storage vessel by calculating the total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels (304) to obtain the average VOC emissions per storage vessel (103 tons/year).Therefore, the nationwide annual costs were estimated to be $4.41 million/yr. A total nationwide VOC emission reduction of 29,746 tons/year results in a cost effectiveness of $149/ton.

7.5.5 Nationwide Secondary Emission Impacts

Regulatory Options 2 (condensate storage vessels) and 3 (crude oil storage vessels) allow for the use of a combustor; therefore the estimated nationwide secondary impacts are a result of combusting 50 percent of all storage vessel emissions. The secondary impacts for controlling a single storage vessel using a combustor are presented in Table 7-9. Nationwide secondary impacts are calculated by

Table 7-13. Nationwide Secondary Combined Impacts for Storage Vessels

Pollutant	Emissions per Storage Vessel (tons/year) [a]	Nationwide Emissions (tons/year)[b]
THC	0.0061	0.927
CO	0.0160	2.43
CO_2	5.62	854
NO_X	2.95E-03	0.448
PM	5.51E-05	0.0084

a. Emissions per storage vessel presented in Table 7-9.
b. Nationwide emissions calculated by assuming that 50 percent of the 304 impacted storage vessels would install a combustor.

multiplying 50 percent of the estimated number of impacted storage vessels (152) by the secondary emissions and are presented in Table 7-13.

7.6 References

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8.0 EQUIPMENT LEAKS

Leaks from components in the oil and natural gas sector are a source of pollutant emissions. This chapter explains the causes for these leaks, and provides emission estimates for “model” facilities in the various segments of the oil and gas sector. In addition, nationwide equipment leak emission estimates from new sources are estimated. Programs that are designed to reduce equipment leak emissions are explained, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for equipment leaks.

8.1 Equipment Leak Description

There are several potential sources of equipment leak emissions throughout the oil and natural gas sector. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. The following sub-sections describe potential equipment leak sources and the magnitude of the volatile emissions from typical facilities in the oil and gas industry.

Due to the large number of valves, pumps, and other components within oil and natural gas production, processing, and/or transmission facilities, total equipment leak VOC emissions from these components can be significant. Tank batteries or production pads are generally small facilities as compared with other oil and gas operations, and are generally characterized by a small number of components. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components.

8.2. Equipment leak Emission Data and Emissions Factors

8.2.1 Summary of Major Studies and Emission Factors

Emissions data from equipment leaks have been collected from chemical manufacturing and petroleum production to develop control strategies for reducing HAP and VOC emissions from these sources.[1,2,3] In the evaluation of the emissions and emission reduction options for equipment leaks, many of these studies were consulted. Table 8-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

8.2.2 Model Plants

Facilities in the oil and gas sector can consist of a variety of combinations of process equipment and components. This is particularly true in the production segment of the industry, where "surface sites" can vary from sites where only a wellhead and associated piping is located to sites where a substantial amount of separation, treatment, and compression occurs. In order to conduct analyses to be used in evaluating potential options to reduce emissions from leaking equipment, a model plant approach was used. The following sections discuss the creation of these model plants.

Information related to equipment counts was obtained from a natural gas industry report. This document provided average equipment counts for gas production, gas processing, natural gas transmission and distribution. These average counts were used to develop model plants for wellheads, well pads, and gathering line and boosting stations in the production segment of the industry, for a natural gas processing plant, and for a compression/transmission station in the natural gas transmission segment. These equipment counts are consistent with those contained in EPA's analysis to estimate methane emissions conducted in support of the Greenhouse Gas Mandatory Reporting Rule (subpart W), which was published in the *Federal Register* on November 30, 2010 (75 FR 74458), These model plants are discussed in the following sections.

8.2.2.1 Oil and Natural Gas Production

Oil and natural gas production varies from site-to site. Many production sites may include only a wellhead that is extracting oil or natural gas from the ground. Other production sites consist of wellheads attached to a well pad. A well pad is a site where the production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) associated with these operations. A well pad can serve one well on a pad or several wells on a pad. A wellhead site consisting of only the wellhead and affiliated piping is not considered to be a well pad. The number of wells feeding into a well pad can vary from one to as many as 7 wells. Therefore, the number of components with potential for equipment leaks can vary depending on the number of wells feeding into the production pad and the amount of processing equipment located at the site.

Table 8-1. Major Studies Reviewed for Consideration or Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor (s)	Emissions Data	Control Options
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Documents	EPA	2010	Nationwide	X	X
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008[4]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry[567]	Gas Research Institute / EPA	1996	Nationwide	X	X
Methane Emissions from the US Petroleum Industry (Draft) [8]	EPA	1996	Nationwide	X	
Methane Emissions from the US Petroleum Industry [9]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [10]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories [11]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[12]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements [13]	Environmental Defense Fund	2009	Regional	X	X
Emissions from oil and Natural Gas Production Facilities [14]	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data[15]	U.S. Energy Information Administration	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations [16]	EPA	1999		X	X
Protocol for Equipment Leak Emission Estimates[17]	EPA	1995	Nationwide	X	X

In addition to wellheads and well pads, model plants were developed for gathering lines and boosting stations. The gathering lines and boosting stations are sites that collect oil and gas from well pads and direct them to the gas processing plants. These stations have similar equipment to well pads; however they are not directly connected to the wellheads.

The EPA/GRI report provided the average number of equipment located at a well pad and the average number of components for each of these pieces of equipment.[4]The type of production equipment located at a well pad include: gas wellheads, separators, meters/piping, gathering compressors, heaters, and dehydrators. The types of components that are associated with this equipment include: valves, connectors, open-ended lines, and pressure relief valves. Four model plants were developed for well pads and are presented in Table 8-2. These model plants were developed starting with one, three, five and seven wellheads, and adding the average numberof other pieces of equipment per wellhead. Gathering compressors are not included at well pads and were included in the equipment for gathering lines and boosting stations.

Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S and the Western U.S. for the EPA/GRI document. A summary of the component counts for oil and gas production well pads is presented in Table 8-3.

Gathering line and boosting station model plants were developed using the average equipment counts for oil and gas production. The average equipment count was assigned Model Plant 2 and Model Plants 1 and 3 were assumed to be equally distributed on either side of the average equipment count. Therefore, Model Plant 1 can be assumed to be a small gathering and boosting station, and Model Plant 3 can be assumed to be a large gathering and boosting station. A summary of the model plant production equipment counts for gathering lines and boosting stations is provided in Table 8-4.

Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S and the Western U.S. from the EPA/GRIdocument. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressors seals are addressed in a Chapter 6 of this document. A summary of the component counts for oil and gas gathering line and boosting stations are presented in Table 8-5.

Table 8-2.Average Equipment Count for Oil and Gas Production Well Pad Model Plants

Equipment	Model Plant 1	Model Plant 2	Model Plant 3
Gas Wellheads	1	5	48
Separators	---	4	40
Meter/Piping	---	2	24
In-Line Heaters	---	2	26
Dehydrators	---	2	19

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and Table 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-3.Average Component Count for Oil and Gas Production Well Pad Model Plants

Component	Model Plant 1	Model Plant 2	Model Plant 3	Model Plant 4
Valve	9	122	235	348
Connectors	37	450	863	1,276
Open-Ended Line	1	15	29	43
Pressure Relief Valve	0	5	10	15

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-4. Average Equipment Count for Oil and Gas Production Gathering Line and Boosting Station Model Plants

Equipment	Model Plant 1	Model Plant 2	Model Plant 3
Separators	7	11	15
Meter/Piping	4	7	10
Gathering Compressors	3	5	7
In-Line Heaters	4	7	10
Dehydrators	3	5	7

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and Table 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-5. Average Component Count for Oil and Gas Production Gathering Line and Boosting Station Model Plants

Component	Model Plant 1	Model Plant 2	Model Plant 3
Valve	547	906	1,265
Connectors	1,723	2,864	4,005
Open-Ended Line	51	83	115
Pressure Relief Valve	29	48	67

DataSource: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8:Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

8.2.2.2 Oil and Natural Gas Processing

Natural gas processing involves the removal of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The types of process equipment used to separate the liquids are separators, glycol dehydrators, and amine treaters. In addition, centrifugal and/or reciprocating compressors are used to pressurize and move the gas from the processing facility to the transmission stations.

New Source Performance Standards (NSPS) have already been promulgated for equipment leaks at new natural gas processing plants (40 CFR Part 60, subpart KKK), and were assumed to be the baseline emissions for this analysis. Only one model plant was developed for the processing sector. A summary of the model plant production components counts for an oil and gas processing facility is provided in Table 8-6.

8.2.2.3 Natural Gas Transmission/Storage

Natural gas transmission/storage stations are facilities that use compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. This source category also does not include emissions from gathering lines and boosting stations. Component counts were obtained from the EPA/GRI report and are presented in Table 8-7.

8.3 Nationwide Emissions from New Sources

8.3.1 Overview of Approach

Nationwide emissions were calculated by using the model plant approach for estimating emissions. Baseline model plant emissions for the natural gas production, processing, and transmission sectors were calculated using the component counts and the component gas service emission factors.[5] Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors for the production and processing sectors that were used to estimate the new source emissions are presented in Table 8-8. Emission factors for the transmission sector are presented in

Table 8-6.Average Component Count for Oil and Gas Processing Model Plant

Component	Gas Plant (non-compressor components)
Valve	1,392
Connectors	4,392
Open-Ended Line	134
Pressure Relief Valve	29

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-13, June 1996. (EPA-600/R-96-080h)

Table 8-7.Average Component Count for a Gas TransmissionFacility

Component	Processing Plant Component Count
Valve	704
Connection	3,068
Open-Ended Line	55
Pressure Relief Valve	14

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-16, June 1996. (EPA-600/R-96-080h)

Table 8-8 Oil and Gas Production and Processing Operations Average Emissions Factors

Component Type	Component Service	Emission Factor (kg/hr/source)
Valves	Gas	4.5E-03
Connectors	Gas	2.0E-04
Open-Ended Line	Gas	2.0E-03
Pressure Relief Valve	Gas	8.8E-03

Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

Table 8-9. Emissions for VOC, hazardous air pollutants (HAP), and methane were calculated using TOC weight fractions.[6] A summary of the baseline emissions for each of the sectors are presented in Table 8-10.

8.3.2 Activity Data

Data from oil and gas technical documents and inventories were used to estimate the number of new sources for each of the oil and gas sectors. Information from the Energy Information Administration (EIA) was used to estimate the number of new wells, well pads, and gathering and boosting stations. The number of processing plants and transmission/storage facilities was estimated using data from the Oil and Gas Journal, and the EPA Greenhouse Gas Inventory. A summary of the steps used to estimate the new sources for each of the oil and gas sectors is presented in the following sections.

8.3.2.1 Well Pads

The EIA provided a forecast of the number of new conventional and unconventional gas wells for the Year 2015 for both exploratory and developmental wells. The EIA projected 19,097 conventional and unconventional gas wells in 2015. The number of wells was converted to number of well pads by dividing the total number of wells by the average number of wells serving a well pad which is estimated to be 5. Therefore, the number of new well pads was estimated to be 3,820. The facilities were divided into the model plants assuming a normal distribution of facilities around the average model plant (Model Plant 2).

8.3.2.2 Gathering and Boosting

The number of new gathering and boosting stations was estimated using the current inventory of gathering compressors listed in the EPA Greenhouse Gas Inventory. The total number of gathering compressors was listed as 32,233 in the inventory. The GRI/EPA document does not include a separate list of compressor counts for gathering and boosting stations, but it does list the average number of compressors in the gas production section. It was assumed that this average of 4.5 compressors for gas production facilities is applicable to gathering and boosting stations. Therefore, using the inventory of 32,233 compressors and the average number of 4.5 compressors per facility, we estimated the number of gathering and boosting stations to be 7,163. To estimate the number of new gathering and boosting stations, we used the same increase of 3.84 percent used to estimate well pads to estimate the number of new gathering and boosting stations. This provided an estimate of 275 new gathering and boosting

Table 8-9 Oil and Gas Transmission/Storage Average Emissions Factors

Component Type	Component Service	Emission Factor (kg/hr/source)
Valves	Gas	5.5E-03
Connectors	Gas	9.3E-04
Open-Ended Line	Gas	7.1E-02
Pressure Relief Valve	Gas	3.98E-02

Data Source:EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-17, June 1996. (EPA-600/R-96-080h)

Table 8-10. Baseline Emissions for the Oil and Gas Production, Processing, and Transmission/Storage Model Plants

Oil and Gas Sector	Model Plant	TOC Emissions (Tons/yr)	Methane Emissions (Tons/yr)	VOC Emissions (Tons/yr)	HAP Emissions (Tons/yr)
Well Pads	1	0.482	0.335	0.0930	0.00351
	2	13.3	9.24	2.56	0.0967
	3	139	96.5	26.8	1.01
Gathering & Boosting	1	30.5	21.2	5.90	0.222
	2	50.6	35.2	9.76	0.368
	3	70.6	49.1	13.6	0.514
Processing	1	74.0	51.4	14.3	0.539
Transmission/Storage	1	108.1	98.1	2.71	0.0806

stations that would be affected sources under the proposed NSPS. The new gathering and boosting stations were assumed to be normally distributed around the average model plant (Model Plant 2).

8.3.2.3 Processing Facilities

The number of new processing facilities was estimated using gas processing data from the Oil and Gas Journal. The Oil and Gas Journal Construction Survey currently shows 6,303 million cubic feet of gas per day (MMcf/day) additional gas processing capacity in various stages of development. The OGJ Gas Processing Survey shows that there is 26.9 trillion cubic feet per year (tcf/year) in existing capacity, with a current throughput of 16.6 tcf/year or 62 percent utilization rate. If the utilization rate remains constant, the new construction would add approximately 1.4 tcf/year to the processing system. This would be an increase of 8.5 percent to the processing sector. The recent energy outlook published by the EIApredicts a 1.03 tcf/year increase in natural gas processing from 21.07 to22.104 tcf/year. This would be an annual increase of 5 percent over the next five years.

The EPA Greenhouse Gas Inventory estimates the number of existing processing facilities to be 577 plants operating in the U.S. Based on the projections provided in Oil and Gas Journal and EIA, it was assumed that the processing sector would increase by 5 percent annually. Therefore the number of new sources was estimated to be 29 new processing facilities in the U.S.

8.3.2.4 Transmission/Storage Facilities

The number of new transmission and storage facilities was estimated using the annual growth rate of 5 percent used for the processing sector and the estimated number of existing transmission and storage facilities in the EPA Greenhouse Inventory. The inventory estimates 1,748 transmission stations and 400 storage facilities for a total of 2,148. Therefore, the number of new transmission/storage facilities was estimated to be 107.

8.3.3 Emission Estimates

Nationwide emission estimates for the new sources for well pads, gathering and boosting, processing, and transmission/storage are summarized in Table 8-11. For well pads and gathering and boosting stations, the numbers of new facilities were assumed to be normally distributed across the range of model plants.

Table 8-11. Nationwide Baseline Emissions for New Sources

Oil and Gas Sector	Model Plant	Number of New Facilities	TOC Emissions (tons/yr)	Methane Emissions (tons/yr)	VOC Emissions (tons/yr)	HAP Emissions (tons/yr)
Well Pads	1	605	292	203	56.3	2.12
	2	2,610	34,687	24,116	6,682	252
	3	605	84,035	58,389	16,214	612
	Total	3,820	119,014	82,708	22,952	866
Gathering & Boosting	1	44	1,312	912	254	9.55
	2	187	9,513	6,618	1,835	69.2
	3	44	3,106	2,160	598	22.6
	Total	275	13,931	9,690	2,687	101
Processing	1	29	2,146	1,490	415	15.6
Transmission/Storage	1	107	11,567	10,497	290	8.62

8.4 Control Techniques

8.4.1 Potential Control Techniques

EPA has determined that leaking equipment, such as valves, pumps, and connectors, are a significant source of VOC and HAP emissions from oil and gas facilities. The following section describes the techniques used to reduce emissions from these sources.

The most effective control technique for equipment leaks is the implementation of a leak detection and repair program (LDAR). Emissions reductions from implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators, decrease exposure of hazardous chemicals to the surrounding community, reduce emissions fees, and help facilities avoid enforcement actions. The elements of an effective LDAR program include:

- Identifying Components;
- Leak Definition;
- Monitoring Components;
- Repairing Components; and
- Recordkeeping.

The primary source of equipment leak emissions from oil and gas facilities are from valves and connectors, because these are the most prevalent components and can number in the thousands. The major cause of emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., leak definition) for the applicable regulation. Leak definitions vary by regulation, component type, service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring interval. Most NSPS regulations have a leak definition of 10,000 ppm, while many NESHAP regulations use a 500-ppm or 1,000-ppm leak definition. In addition, some regulations define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting or clouding from or around components), sound (such as hissing), and smell.

For many NSPS and NESHAP regulations with leak detection provisions, the primary method for monitoring to detect leaking components is EPA Reference Method 21 (40 CFR Part 60, Appendix A). Method 21 is a procedure used to detect VOC leaks from process equipment using toxic vapor analyzer (TVA) or organic vapor analyzer (OVA). In addition, other monitoring tools such as; infrared camera, soap solution, acoustic leak detection, and electronic screening device, can be used to monitor process components.

In optical gas imaging, a live video image is produced by illuminating the view area with laser light in the infrared frequency range. In this range, hydrocarbons absorb the infrared light and are revealed as a dark image or cloud on the camera. The passive infrared cameras scan an area to produce images of equipment leaks from a number of sources. Active infrared cameras point or aim an infrared beam at a potential source to indicate the presence of equipment leaks. The optical imaging camera is easy to use and very efficient in monitoring many components in a short amount of time. However, the optical imaging camera cannot quantify the amount or concentration of equipment leak. To quantify the leak, the user would need to measure the concentration of the leak using a TVA or OVA. In addition, the optical imaging camera has a high upfront capital cost of purchasing the camera.

Acoustic leak detectors measure the decibel readings of high frequency vibrations from the noise of leaking fluids from equipment leaks using a stethoscope-type device. The decibel reading, along with the type of fluid, density, system pressure, and component type can be correlated into leak rate by using algorithms developed by the instrument manufacturer. The acoustic detector does not decrease the monitoring time because components are measured separately, like the OVA or TVA monitoring. The accuracy of the measurements using the acoustic detector can also be questioned due to the number of variables used to determine the equipment leak emissions.

Monitoring intervals vary according to the applicable regulation, but are typically weekly, monthly, quarterly, and yearly. For connectors, the monitoring interval can be every 1, 2, 4, or 8 years. The monitoring interval depends on the component type and periodic leak rate for the component type. Also, many LDAR requirements specify weekly visual inspections of pumps, agitators, and compressors for indications of liquids leaking from the seals. For each component that is found to be leaking, the first attempt at repair is to be made no later than five calendar days after each leak is detected. First attempts at repair include, but are not limited to, the following best practices, where practicable and appropriate:

- Tightening of bonnet bolts;

- Replacement of bonnet bolts;
- Tightening of packing gland nuts; and
- Injection of lubricant into lubricated packing.

Once the component is repaired; it should be monitored daily over the next several days to ensure the leak has been successfully repaired. Another method that can be used to repair component is to replace the leaking component with “leakless” or other technologies.

The LDAR recordkeeping requirement for each regulated process requires that a list of all ID numbers be maintained for all equipment subject to an equipment leak regulation. A list of components that are designated as “unsafe to monitor” should also be maintained with an explanation/review of conditions for the designation. Detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams should also be maintained with the results of performance testing and leak detection monitoring, which may include leak monitoring results per the leak frequency, monitoring leakless equipment, and non-periodic event monitoring.

Other factors that can improve the efficiency of an LDAR program that are not addressed by the standards include training programs for equipment monitoring personnel and tracking systems that address the cost efficiency of alternative equipment (e.g., competing brands of valves in a specific application).

The first LDAR option is the implementation of a subpart VVa LDAR program. This program is similar to the VV monitoring, but finds more leaks due to the lower leak definition, thereby achieving better emission reductions. The VVa LDAR program requires the annual monitoring of connectors using an OVA or TVA (10,000 ppm leak definition), monthly monitoring of valves (500 ppm leak definition) and requires open-ended lines and pressure relief devices to operate with no detectable emissions (500 ppm leak definition). The monitoring of each of the equipment types were also analyzed as a possible option for reducing equipment leak emissions. The second option involves using the monitoring requirements in subpart VVa for each type of equipment which include: valves; connectors; pressure relief devices; and open-ended lines for each of the oil and gas sectors.

The thirdoption that was investigated was the implementation of a LDAR program using an optical gas imaging system. This option is currently available as an alternative work practice (40 CFR Part 60, subpart A) for monitoring emissions from equipment leaks in subpart VVa. The alternative work practice requires monthly monitoring of all components using the optical gas imaging system and an annual monitoring of all components using a Method 21 monitoring device. The Method 21 monitoring allows the facility to quantify emissions from equipment leaks, since the optical gas imaging system can only provide the magnitude of the equipment leaks.

A fourth option that was investigated is a modification of the 40 CFR Part 60, subpart Aalternative work practice. The alternative work practice was modified by removing the required annual monitoring using a Method 21 instrument. This option only requires the monthly monitoring of components using the optical gas imaging system.

8.4.2 Subpart VVa LDAR Program

8.4.2.1 Description

The subpart VVa LDAR requires the monitoring of pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors. These components are monitored with an OVA or TVA to determine if a component is leaking and measure the concentration of the organics if the component is leaking. Connectors, valves, and pressure relief devices have a leak definition of 500 parts per million by volume (ppmv). Valves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves have no monitoring requirements, but are required to operate without any detectable emissions. Compressors are not included in this LDAR option and are regulated separately.

8.4.2.2 Effectiveness

The control effectiveness of the LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks. A summary of the chemical manufacturing and petroleum refinery control effectiveness for each of the components is shown in Table 8-12. As shown in the table the control effectiveness for all of the components varies from 45 to 96 percent and is dependent on the frequency of monitoring and the leak definition. Descriptions of the frequency of monitoring and leak definition are described further below.

> Monitoring Frequency: The monitoring frequency is the number of times each component is checked for leaks. For an example, quarterly monitoring requires that each component be checked for leaks 4 times per year, and annual monitoring requires that each component be checked for leaks once per year. As shown in Table 8-12, monthly monitoring provides higher control effectiveness than quarterly

Table 8-12. Control Effectiveness for an LDAR program at a Chemical Process Unit and a Petroleum Refinery

Equipment Type and Service	Control Effectiveness (% Reduction)		
	Monthly Monitoring 10,000 ppmv Leak Definition	Quarterly Monitoring 10,000 ppmv Leak Definition	500 ppm Leak Definition[a]
Chemical Process Unit			
Valves – Gas Service[b]	87	67	92
Valves – Light Liquid Service[c]	84	61	88
Pumps – Light Liquid Service[c]	69	45	75
Connectors – All Services	---	---	93
Petroleum Refinery			
Valves – Gas Service[b]	88	70	96
Valves – Light Liquid Service[c]	76	61	95
Pumps – Light Liquid Service[c]	68	45	88
Connectors – All Services	---	---	81

Source: Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Nov 1995.

a. Control effectiveness attributable to the HON-negotiated equipment leak regulation (40 CFR 63, Subpart H) is estimated based on equipment-specific leak definitions and performance levels. However, pumps subject to the HON at existing process units have a 1,000 to 5,000 ppm leak definition, depending on the type of process.
b. Gas (vapor) service means the material in contact with the equipment component is in a gaseous state at the process operating conditions.
c. Light liquid service means the material in contact with the equipment component is in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure above 0.3 kilopascals (kPa) at 20°C is greater than or equal to 20% by weight.

monitoring. This is because leaking components are found and repaired more quickly, which lowers the amount of emissions that are leaked to the atmosphere.

> <u>Leak Definition:</u> The leak definition describes the local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound. Decreasing the leak definition concentration generally increases the number of leaks found during a monitoring period, which generally increases the number of leaks that are repaired.

The control effectiveness for the well pad, gathering and boosting stations, processing facilities, and transmissions and storage facilities were calculated using the LDAR control effectiveness and leak fraction equations for oil and gas production operation units in the EPA equipment leaks protocol document. The leak fraction equation uses the average leak rate (e.g., the component emission factor) and leak definition to calculate the leak fraction.[7] This leak fraction is used in a steady state set of equations to determine the final leak rate after implementing a LDAR program.[8] The initial leak rate and the final leak rate after implementing a LDAR program were then used to calculate the control effectiveness of the program. The control effectiveness for implementing a subpart VVa LDAR program was calculated to be 93.6 perccent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.2.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Subpart VVa monitoring frequency and leak definition were used for processing plants since they are already required to do subpart VV requirements. Connectors were assumed to be monitored over a 4-year period after initial annual compliance monitoring.
- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Subsequent monitoring costs are $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

It was assumed that a single Method 21 monitoring device could be used at multiple locations for production pads, gathering and boosting stations, and transmission and storage facilities. To calculate the shared cost of the Method 21 device, the time required to monitor a single facility was estimated. For production pads and gathering and boosting stations, it was assumed that it takes approximately 1 minute to monitor a single component, and approximately 451 components would have to be monitored at an average facility in a month. This calculates to be 451 minutes or 7.5 hours per day. Assuming 20 working days in a typical month, a single Method 21 device could monitor 20 facilities. Therefore, the capital cost of the Method 21 device ($6,500) was divided by 20 to get a shared capital cost of $325 per facility. It was assumed for processing facilities that the full cost of the Method 21 monitoring device would apply to each individual plant. The transmission and storage segment Method 21 device cost was estimated using assuming the same 1 minute per component monitoring time. The average number of components that would need to be monitored in a month was estimated to be 1,440, which calculates to be 24 hours of monitoring time or 3 days. Assuming the same 20 day work month, the total number of facilities that could be monitored by a single Method 21 device is 7. Therefore, the shared cost of the Method 21 monitoring device was calculated to be $929 per site.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectors are provided in Table 8-13. In addition to the full subpart VVa LDAR monitoring, a component by component LDAR analysis was performed for each of the oil and gas sectors using the component count for an average size facility. This Model Plant 2 for well pads, Model Plant 2 for gathering and boosting stations, and Model Plant 1 for processing plants and transmission and storage facilities.

Table 8-13. Summary of the Model Plant Cost Effectiveness for the Subpart VVa Option

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	0.0876	0.00330	0.315	$15,418	$23,423	$23,350	$267,386	$7,088,667	$74,253
2	2.43	0.0915	8.73	$69,179	$37,711	$35,687	$15,549	$412,226	$4,318
3	25.3	0.956	91.3	$584,763	$175,753	$154,595	$6,934	$183,835	$1,926
Gathering and Boosting Stations									
1	5.58	0.210	20.1	$148,885	$57,575	$52,921	$10,327	$273,769	$2,868
2	9.23	0.348	33.2	$255,344	$84,966	$77,259	$9,203	$243,987	$2,556
3	12.9	0.486	46.4	$321,203	$105,350	$94,591	$8,174	$216,692	$2,270
Processing Plants									
1	13.5	0.508	48.5	$7,522	$45,160	$33,915	$3,352	$88,870	$931
Transmission/Storage Facilities									
1	2.62	0.0780	94.9	$94,482	$51,875	N/A	$19,769	$665,155	$546

Note: Transmission and storage facilities do not own the natural gas; therefore they do not receive any cost benefits from reducing the amount of natural gas as the result of equipment leaks.

The component costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Subsequent monitoring costs are $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.
- Administrative costs and initial planning and training costs are were included for the component option and are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost for purchasing a TVA or OVA monitoring system was estimated to be $6,500.

The component control effectiveness for the subpart VVa component option were 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices. These were the same control effectiveness's that were used for the subpart VVa facility option. The control effectiveness for the modified subpart VVa option with less frequent monitoring was estimated assuming the control effectiveness follows a hyperbolic curve or a 1/x relationship with the monitoring frequency. Using this assumption the component cost effectiveness's were determined to be 87.2 percent for valves, 81.0 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices. The assumption is believed to provide a conservative estimate of the control efficiency based on less frequent monitoring. A summary of the capital and annual costs and the cost effectiveness for each of the components for each of the oil and gas sectors are provided in Tables 8-14, 8-15, 8-16, and 8-17.

8.4.2.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

Table 8-14. Summary of Component Cost Effectiveness for Well Pads for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	235	12	1.84	0.0696	6.64	$11,175	$27,786	$15,063	$399,331	$4,183
Connectors	863	1/0.25[a]	0.308	0.0116	1.11	$7,830	$22,915	$74,283	$1,969,328	$20,628
PRD	10	0	0.164	0.00619	0.591	$48,800	$29,609	$180,537	$4,786,215	$50,135
OEL	29	0	0.108	0.00408	0.389	$9,458	$22,915	$211,992	$5,620,108	$58,870
Modified Subpart VVa– Less Frequent Monitoring										
Valves	235	1	1.31	0.0496	4.73	$11,175	$23,436	$17,828	$472,640	$4,951
Connectors	863	1/0.125[b]	0.261	0.00983	0.938	$7,830	$22,740	$87,277	$2,313,795	$24,237
PRD	5	0	0.164	0.00619	0.591	$48,800	$29,609	$180,537	$4,786,215	$50,135
OEL	29	0	0.108	0.00408	0.389	$9,458	$22,915	$211,992	$5,620,108	$58,870

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.

b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

Table 8-15. Summary of Component Cost Effectiveness for Gathering and Boosting Stations for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	906	12	7.11	0.268	25.6	$24,524	$43,234	$6,079	$161,162	$1,688
Connectors	2,864	1/0.25[a]	1.02	0.0386	3.69	$10,914	$24,164	$23,603	$625,752	$6,555
PRD	48	0	0.787	0.0297	2.83	$195,140	$57,091	$72,523	$1,922,648	$20,139
OEL	83	0	0.309	0.0117	1.11	$14,966	$23,917	$77,310	$2,049,557	$21,469
Modified Subpart VVa – Less Frequent Monitoring										
Valves	906	1	5.07	0.191	18.2	$24,524	$24,461	$5,221	$138,417	$1,450
Connectors	2,864	1/0.125[b]	0.865	0.0326	3.11	$10,914	$23,584	$27,274	$723,067	$7,574
PRD	48	0	0.787	0.0297	2.83	$195,140	$57,091	$72,523	$1,922,648	$20,139
OEL	83	0	0.309	0.0117	1.11	$14,966	$23,917	$77,310	$2,049,557	$21,469

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

Table 8-16. Summary of Incremental Component Cost Effectiveness for Processing Plants for the Subpart VVa Option

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Incremental Component Cost for Subpart VV to Subpart VVa Option										
Valves	1,392	12	10.9	0.412	39.3	$6,680	$1,576	$144	$3,824	$40
Connectors	4,392	1/0.25[a]	1.57	0.0592	5.65	$2,559	$6,845	$4,360	$115,585	$1,211
PRD	29	0	0.499	0.0188	1.80	$0	$0	$0	$0	$0
OEL	134	0	0.476	0.0179	1.71	$0	$0	$0	$0	$0

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.

Table 8-17. Summary of Component Cost Effectiveness for Transmission and Storage Facilities for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	673	12	0.878	0.0261	31.8	$19,888	$37,870	$43,111	$1,450,510	$1,192
Connectors	3,068	1/0.25[a]	0.665	0.0198	24.1	$11,229	$24,291	$36,527	$1,229,005	$1,010
PRD	14	0	0.133	0.00397	4.83	$61,520	$32,501	$243,525	$8,193,684	$6,732
OEL	58	0	0.947	0.0282	34.3	$12,416	$23,453	$24,762	$833,137	$684
Modified Subpart VVa – Less Frequent Monitoring										
Valves	673	1	0.626	0.0186	22.6	$19,888	$25,410	$40,593	$1,365,801	$1,122
Connectors	3,068	1/0.125[b]	0.562	0.0167	20.3	$11,229	$23,669	$42,140	$1,417,844	$1,165
PRD	14	0	0.133	0.00397	4.83	$61,520	$32,501	$243,525	$8,193,684	$6,732
OEL	58	0	0.947	0.0282	34.3	$12,416	$23,453	$24,762	$833,137	$684

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

8.4.3 LDAR with Optical Gas Imaging

8.4.3.1 Description

The alternative work practice for equipment leaks in §60.18 of 40 CFR Part 60, subpart A allows the use of an optical gas imaging system to monitor leaks from components. This LDAR requires monthly monitoring and repair of components using an optical gas imaging system, and annual monitoring of components using a Method 21 instrument. This requirement does not have a leak definition because the optical gas imaging system can only measure the magnitude of a leak and not the concentration. However, this alternative work practice does not require the repair of leaks below 500 ppm. Compressors are not included in this LDAR option and arediscussed in Chapter 6 of this document.

8.4.3.2 Effectiveness

No data was found on the control effectiveness of the alternative work practice. It is believed that this option would provide the same control effectiveness as the subpart VVa monitoring program. Therefore, the control effectiveness's for implementing an alternative work practice was assumed to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.3.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are \$17.70 for valves, \$1.13 per connector, \$78.00 for pressure relief valve disks, \$3,852 for pressure relief valve disk holder and valves, and \$102 for open-ended lines.
- Monthly optical gas imaging monitoring costs are estimated to be \$0.50 for valves, connectors, pressure relief valve devices, and open-ended lines.
- Annual monitoring costs using a Method 21 device are estimated to be \$1.50 for valves and connectors, \$2.00 for pressure relief valve disks, and \$5.00 for pressure relief devices and open-ended lines.
- A wage rate of \$30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

It was assumed that a single optical gas imaging and a Method 21 monitoring device could be used at multiple locations for production pads, gathering and boosting stations, and transmission and storage facilities. To calculate the shared cost of the optical gas imaging system and the Method 21 device, the time required to monitor a single facility was estimated. For production pads and gathering and boosting stations, it was assumed that 8 production pads could be monitored per day. This means that 160 production facilities could be monitored in a month. In addition, it was assumed 13 gathering and boosting station would service these wells and could be monitored during the same month for a total of 173 facilities. Therefore, the capital cost of the optical gas imaging system (Flir Model GF320, $85,000) and the Method 21 device ($6,500) was divided by 173 to get a shared capital cost of $529 per facility. It was assumed for processing facilities that the full cost of the optical gas imaging system and the Method 21 monitoring device would apply to each individual plant. The transmission and storage segment Method 21 device cost was estimated assuming that one facility could be monitored in one hour, and the travel time between facilities was one hour. Therefore, in a typical day 4 transmission stations could be monitored in one day. Assuming the same 20 day work month, the total number of facilities that could be monitored by a single optical gas imaging system and Method 21 device is 80. Therefore, the shared cost of the Method 21 monitoring device was calculated to be $1,144 per site.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectorusing the alternative work practice monitoring is provided in Table 8-18. A component cost effectiveness analysis for the alternative work practice was not performed, because the optical gas imaging system is not conducive to component monitoring, but is intended for facility-wide monitoring.

8.4.3.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of

Table 8-18. Summary of the Model Plant Cost Effectiveness for the Optical Gas Imaging and Method 21 Monitoring Option

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	0.0876	0.00330	0.315	$15,428	$21,464	$21,391	$245,024	$6,495,835	$68,043
2	2.43	0.0915	8.73	$64,858	$39,112	$37,088	$16,127	$427,540	$4,478
3	25.3	0.956	91.3	$132,891	$135,964	$114,807	$5,364	$142,216	$1,490
Gathering and Boosting Stations									
1	5.58	0.210	20.1	$149,089	$63,949	$59,295	$11,470	$304,078	$3,185
2	9.23	0.348	33.2	$240,529	$93,210	$85,503	$10,096	$267,659	$2,804
3	12.9	0.486	46.4	$329,725	$121,820	$111,060	$9,451	$250,567	$2,625
Processing Plants									
1	13.5	0.508	48.5	$92,522	$87,059	$75,813	$6,462	$171,321	$1,795
Transmission/Storage Facilities									
1	2.62	0.0780	94.9	$20,898	$51,753	N/A	$19,723	$663,591	$545

Minor discrepancies may be due to rounding.

Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission segment..

equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

8.4.4 Modified Alternative Work Practice with Optical Gas Imaging

8.4.4.1 Description

The modified alternative work practice for equipment leaks in §60.18 of 40 CFR Part 60, subpart A allows the use of an optical gas imaging system to monitor leaks from components, but removes the requirement of the annual Method 21 device monitoring. Therefore, the modified work practice would require only monthly monitoring and repair of components using an optical gas imaging system. This requirement does not have a leak definition because the optical gas imaging system can only measure the magnitude of a leak and not the concentration. However, this alternative work practice does not require the repair of leaks below 500 ppm. Compressors are not included in this LDAR option and are regulated separately.

8.4.4.2 Effectiveness

No data was found on the control effectiveness of this modified alternative work practice. However, it is believed that this option would provide the similar control effectiveness and emission reductions as the subpart VVa monitoring program. Therefore, the control effectiveness's for implementing an alternative work practice was assumed to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.4.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Monthly optical gas imaging monitoring costs are estimated to be $0.50 for valves, connectors, pressure relief valve devices, and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The shared capital cost for optical gas imaging system is $491 for production and gathering and boosting, $85,000 for processing, and $1,063 for transmission for a FLIR Model GF320 optical gas imaging system.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectors using the alternative work practice monitoring is provided in Table 8-19. A component cost effectiveness analysis for the alternative work practice was not performed, because the optical gas imaging system is not conducive to component monitoring, but is intended for facility-wide monitoring.

8.4.4.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

8.5 Regulatory Options

The LDAR pollution prevention approach is believed to be the best method for reducing pollutant emissions from equipment leaks. Therefore, the following regulatory options were considered for reducing equipment leaks from well pads, gathering and boosting stations, processing facilities, and transmission and storage facilities:

- Regulatory Option 1: Require the implementation of a subpart VVa LDAR program;
- Regulatory Option 2: Require the implementation of a component subpart VVa LDAR program;
- Regulatory Option 3: Require the implementation of the alternative work practice in §60.18 of 40 CFR Part 60;

Table 8-19. Summary of the Model Plant Cost Effectiveness for Monthly Gas Imaging Monitoring

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	N/A	N/A	N/A	$15,390	$21,373	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	$64,820	$37,049	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	$537,313	$189,174	N/A	N/A	N/A	N/A
Gathering and Boosting Stations									
1	N/A	N/A	N/A	$149,051	$59,790	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	$240,491	$86,135	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	$329,687	$11,940	N/A	N/A	N/A	N/A
Processing Plants									
1	N/A	N/A	N/A	$92,522	$76,581	N/A	N/A	N/A	N/A
Transmission/Storage Facilities									
1	N/A	N/A	N/A	$20,817	$45,080	N/A	N/A	N/A	N/A

Note: This option only provides the number and magnitude of the leaks. Therefore, the emission reduction from this program cannot be quantified and the cost effectiveness values calculated.

- Regulatory Option 4: Require the implementation of a modified alternative work practice in §60.18 of 40 CFR Part 60 that removes the requirement for annual monitoring using a Method 21 device.

The following sections discuss these regulatory options.

8.5.1 Evaluation of Regulatory Options for Equipment Leaks

8.5.1.1 Well pads

The first regulatory option of a subpart VVa LDAR program was evaluated for well pads, which include the wells, processing equipment (separators, dehydrators, acid gas removal), as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. For well pads the VOC cost effectiveness for the model plants ranged from $267,386 per ton of VOC for a single well head facility to $6,934 ton of VOC for a well pad servicing 48 wells. Because of the high VOC cost effectiveness, Regulatory Option 1 was rejected for well pads.

The second regulatory option that was evaluated for well pads was Regulatory Option 2, which would require the implementation of a component subpart VVa LDAR program. The VOC cost effectiveness of this option ranged from $15,063 for valves to $211,992 for open-ended lines. These costs were determined to be unreasonable and therefore this regulatory option was rejected.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option ranged from $5,364 per ton of VOC for Model Plant 3to $245,024 per ton of VOC for Model Plant 1. This regulatory option was determined to be not cost effective and was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.2 Gathering and Boosting Stations

The first regulatory option was evaluated for gathering and boosting stations which include the processing equipment (separators, dehydrators, acid gas removal), as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. The VOC cost effectiveness for the gathering and boosting model plants ranged from $10,327 per ton of VOC for

Model Plant 1 to $8,174per ton of VOC for Model Plant 3. Regulatory Option 1 was rejected due to the high VOC cost effectiveness.

The second regulatory option that was evaluated for gathering and boosting stations was Regulatory Option 2. The VOC cost effectiveness of this option ranged from $6,079 for valves to $77,310 per ton of VOC for open-ended lines. These costs were determined to be unreasonable and therefore this regulatory option was also rejected.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option was calculated to be $10,724 per ton of VOC for Model Plant 1 and $8,685 per ton of VOC for Model Plant 3. This regulatory option was determined to be not cost effective and was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.3 Processing Plants

The VOC cost effectiveness of the first regulatory option was calculated to be $3,352 per ton of VOC. This cost effectiveness was determined to be reasonable and therefore this regulatory option was accepted.

The second option was evaluated for processing plants and the VOC cost effectiveness ranged from $0 for open-ended lined and pressure relief devices to $4,360 for connectors. Because the emission benefits and the cost effectiveness of Regulatory Option 1 were accepted, this option was not accepted.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option was calculated to be $6,462 per ton of VOC and was determined to be not cost effective. Therefore, this regulatory option was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.4 Transmission and Storage Facilities

The first regulatory option was evaluated for transmission and storage facilities which include separators and dehydrators, as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. This sector moves processed gas from the processing facilities to the city gates. The VOC cost effectiveness for Regulatory Option 1 was $19,769per ton of VOC. The high VOC cost effectiveness is due to the inherent low VOC concentration in the processed natural gas, therefore the VOC reductions from this sector are low in comparison to the other sectors. Regulatory Option 1 was rejected due to the high VOC cost effectiveness.

The second option was evaluated for transmission facilities and the VOC cost effectiveness ranged from $24,762 for open-ended lined to $243,525 for connectors. This option was not accepted because of the high cost effectiveness.

The third regulatory option that was evaluated for transmission and storage facilities was Regulatory Option 3. The VOC cost effectiveness of this option was calculated to be $19,723 per ton of VOC. Again, because of the low VOC content of the processed gas, the regulatory option has a low VOC reduction. This cost was determined to be unreasonable and therefore this regulatory option was also rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.2 Nationwide Impacts of Regulatory Options

Regulatory Option 1 was selected as an option for setting standards for equipment leaks at processing plants. This option would require the implementation of an LDAR program using the subpart VVa requirements. For production facilities, 29 facilities per year are expected to be affected sources by the NSPS regulation annually. Table 8-20 provides a summary of the expected emission reductions from the implementation of this option.

Table 8-20. Nationwide Emission and Cost Analysis of Regulatory Options

Category	Estimated Number of Sources subject to NSPS	Facility Capital Cost ($)	Nationwide Emission Reductions (tpy)			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
			VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 2 (Subpart VVa LDAR Program)												
Processing Plants	29	$7,522	392	1,407	14.7	$3,352	$2,517	$931	$699	0.218	1.31	0.984

8.6 References

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APPENDIX A

E&P TANKS ANALYSIS FOR STORAGE VESSELS

Tank ID	Sample Tank No. 1	Sample Tank No. 2	Sample Tank No. 3	Sample Tank No. 4	Sample Tank No. 5	Sample Tank No. 6	Sample Tank No. 7	Sample Tank No. 8
E&P Tank Number	**Tank No. 58**	**Tank No. 59**	**Tank No. 60**	**Tank No. 61**	**Tank No. 62**	**Tank No. 63**	**Tank No. 64**	**Tank No. 65**
Total Emissions (tpy)	289.778	230.196	129.419	129.853	201.547	738.511	294.500	142.371
VOC Emissions (tpy)	43.734	111.414	101.853	63.343	154.313	578.379	205.794	89.728
Methane Emissions (tpy)	0.197	56.006	10.064	50.910	8.343	47.831	26.305	24.276
HAP Emissions (tpy)	**4.236**	**13.100**	**5.050**	**2.730**	**3.500**	**37.840**	**4.480**	**2.680**
Benzene	*0.828*	*6.343*	*0.501*	*0.285*	*0.051*	*7.568*	*0.116*	*0.219*
Toluene	*1.194*	*3.539*	*0.648*	*0.243*	*0.067*	*5.950*	*0.085*	*0.301*
E-Benzene	*0.041*	*0.083*	*0.040*	*0.008*	*0.002*	*0.086*	*0.006*	*0.020*
Xylenes	*0.165*	*0.327*	*0.233*	*0.066*	*0.046*	*0.679*	*0.018*	*0.152*
n-C6	*2.008*	*2.809*	*3.623*	*2.132*	*3.333*	*23.553*	*4.252*	*1.989*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	66	66	13	64	28	95	29	44
Separator Temperature (F)	83	90	110	74	78	118	60	71
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	83	90	110	74	78	118	60	71
C10+ SG	0.848	0.865	0.879	0.866	0.864	0.862	0.841	0.849
C10+ MW	234	237	294	301	281	312	224	349
API Gravity	**40.0**	**40.0**	**40.0**	**40.0**	**42.0**	**42.0**	**44.0**	**44.0**
Production Rate (bbl/day)	500	500	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.00	4.10	4.80	3.90	4.20	8.10	5.70	7.00
GOR (scf/bbl)	25.96	30.32	12.30	19.58	19.68	68.74	32.46	16.92
Heating Value of Vapor (Btu/s	398.80	1689.70	2486.42	1567.19	2261.27	2529.29	2162.56	2003.83
LP Oil Component	mol %							
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	5.0200	0.2700	0.0000	0.0800	0.0400	0.0000	0.0100	0.0200
N2	0.0000	0.0100	0.0000	0.0200	0.3100	0.0200	0.0200	0.0100
C1	0.0100	2.2600	0.4700	2.6500	0.4000	2.2500	1.1300	1.2900
C2	0.0400	1.2000	0.4800	0.3900	0.6500	3.1100	1.4100	1.0300
C3	0.2000	1.3200	1.5800	0.9200	1.7500	4.1100	3.2900	2.3000
i-C4	0.2800	0.7100	0.6200	0.9800	0.9200	1.3300	0.4500	1.1200
n-C4	0.4800	1.0800	2.6100	1.4700	2.4500	3.8100	4.0200	3.2200
i-C5	0.7600	1.2000	1.8100	2.0500	2.3900	2.5400	0.7000	2.3600
n-C5	0.7400	1.1300	2.9300	2.1600	2.9500	3.5100	4.0700	2.9600
C6	1.5100	2.0000	3.8800	3.4500	2.7600	3.0900	0.9600	3.0600
C7	4.6600	6.7600	10.7300	7.9400	10.8800	8.0100	5.5900	9.5000
C8	6.6100	9.4200	12.5300	9.6900	11.6400	7.6800	5.5200	11.5900
C9	4.8700	6.5600	6.9400	6.5600	6.1800	4.4400	4.2700	6.3200
C10+	70.1100	49.2600	47.3100	56.3900	52.0200	47.6400	63.0500	47.7200
Benzene	0.5700	4.9100	0.5800	0.4300	0.0700	1.3400	0.1600	0.3600
Toluene	2.1400	7.7900	1.9900	1.1000	0.2700	2.6800	0.3700	1.4900
E-Benzene	0.1700	0.4600	0.2900	0.1000	0.0200	0.0900	0.0700	0.2600
Xylenes	0.7600	2.0500	1.9000	0.9000	0.5500	0.8000	0.2500	2.2900
n-C6	1.0700	1.6100	3.3500	2.7200	3.7500	3.5500	4.6600	3.1000
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 9**	**Sample Tank No. 10**	**Sample Tank No. 11**	**Sample Tank No. 12**	**Sample Tank No. 13**	**Sample Tank No. 14**	**Sample Tank No. 15**
E&P Tank Number	**Tank No. 66**	**Tank No. 67**	**Tank No. 68**	**Tank No. 69**	**Tank No. 70**	**Tank No. 71**	**Tank No. 72**
Total Emissions (tpy)	357.688	134.789	314.446	505.131	306.443	256.029	1061.274
VOC Emissions (tpy)	243.348	79.118	224.158	437.555	252.987	204.571	987.647
Methane Emissions (tpy)	56.846	37.876	18.892	21.472	15.159	21.237	32.940
HAP Emissions (tpy)	**5.590**	**5.680**	**7.030**	**13.450**	**15.330**	**6.500**	**56.780**
Benzene	*0.244*	*1.308*	*0.242*	*0.119*	*1.048*	*0.464*	*5.791*
Toluene	*0.440*	*1.184*	*0.385*	*0.146*	*1.488*	*0.927*	*6.793*
E-Benzene	*0.039*	*0.029*	*0.043*	*0.019*	*0.062*	*0.051*	*0.303*
Xylenes	*0.208*	*0.488*	*0.167*	*0.162*	*0.734*	*0.590*	*4.255*
n-C6	*4.661*	*2.671*	*6.191*	*13.008*	*12.001*	*4.468*	*39.634*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	60	41	20	23	24	52	45
Separator Temperature (F)	60	72	68	85	114	108	140
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	72	68	85	114	108	140
C10+ SG	0.878	0.854	0.926	0.848	0.87	0.886	0.893
C10+ MW	270	270	290	275	274	269	277
API Gravity	**44.0**	**45.0**	**45.0**	**46.0**	**46.0**	**47.0**	**47.0**
Production Rate (bbl/day)	500	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.10	5.20	8.10	4.70	5.00	5.30	6.00
GOR (scf/bbl)	41.30	17.66	30.80	43.26	26.30	24.28	78.80
Heating Value of Vapor (Btu/s	2060.54	1812.87	2234.66	2651.81	2611.90	2491.55	3120.85
LP Oil Component							
H2S	0.0000	0.0000	0.0000	0.0500	0.0700	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0500	0.0400	0.3100	0.2400	0.1700	0.0000	0.0400
N2	0.0000	0.0100	0.0200	0.0100	0.0000	0.0000	0.0000
C1	2.3400	1.8400	0.6900	0.9400	0.6200	0.9700	1.2100
C2	1.5600	0.6100	0.9400	0.6600	0.5200	0.7700	0.7600
C3	3.8500	1.2700	2.7300	2.1500	1.6800	2.0200	2.9200
i-C4	1.3600	0.8900	1.7300	1.1100	0.9900	1.5500	4.1500
n-C4	3.9600	1.5600	3.9300	4.5400	3.1200	2.1400	3.0600
i-C5	3.1300	1.8000	3.8800	3.0600	2.4500	3.3400	3.9300
n-C5	4.0300	1.8800	4.1000	4.9800	3.4200	2.8800	3.0900
C6	3.6100	3.4300	5.1500	4.1100	4.4300	3.2600	4.9100
C7	7.7900	10.7400	12.0700	10.2100	8.8900	9.0800	13.0800
C8	13.7700	12.6900	18.2000	10.6800	18.5800	11.7900	14.6200
C9	4.8300	7.8700	8.8800	5.4300	8.7200	5.8500	7.6300
C10+	42.2300	43.0100	27.3600	45.2800	36.2600	49.3100	31.1400
Benzene	0.2400	1.5600	0.3000	0.0600	0.5300	0.3000	0.6900
Toluene	1.3400	3.8100	1.4700	0.2100	1.9700	1.6000	1.9400
E-Benzene	0.3200	0.2200	0.4400	0.0700	0.1900	0.2100	0.1900
Xylenes	1.9700	4.1900	1.9600	0.6700	2.5500	2.7300	2.9800
n-C6	3.6200	2.5800	5.8400	5.5400	4.8400	2.2000	3.6600
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 16	Sample Tank No. 17	Sample Tank No. 18	Sample Tank No. 19	Sample Tank No. 20	Sample Tank No. 21
E&P Tank Number	**Tank No. 73**	**Tank No. 74**	**Tank No. 75**	**Tank No. 76**	**Tank No. 77**	**Tank No. 78**
Total Emissions (tpy)	464.597	214.658	1331.488	3972.618	540.533	1228.897
VOC Emissions (tpy)	383.349	135.482	1146.617	2331.105	399.555	940.078
Methane Emissions (tpy)	18.132	32.283	31.967	755.826	38.624	105.184
HAP Emissions (tpy)	**10.980**	**7.530**	**77.780**	**82.380**	**7.580**	**13.230**
Benzene	*0.222*	*1.269*	*7.661*	*12.470*	*2.447*	*0.543*
Toluene	*0.208*	*0.708*	*3.775*	*23.584*	*1.643*	*0.466*
E-Benzene	*0.058*	*0.019*	*0.113*	*0.056*	*0.051*	*0.006*
Xylenes	*0.193*	*0.411*	*0.929*	*0.635*	*0.256*	*0.052*
n-C6	*10.296*	*5.124*	*65.304*	*45.632*	*3.186*	*12.160*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	40	31	50	700	20	98
Separator Temperature (F)	76	76	125	100	48	40
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	76	76	125	100	48	40
C10+ SG	0.885	0.839	0.842	0.878	0.877	0.929
C10+ MW	318	296	287	178	179	324
API Gravity	**47.0**	**49.0**	**49.0**	**50.0**	**50.0**	**51.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.60	5.00	8.90	7.40	9.40	11.20
GOR (scf/bbl)	41.32	24.48	106.60	491.90	56.44	128.16
Heating Value of Vapor (Btu/s	2421.27	2045.68	2822.40	1916.15	2275.04	2279.83
LP Oil Component						
H2S	0.0000	0.0000	1.2800	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0400	0.0800	0.0300	0.4200	0.0100	0.0100
N2	0.8400	0.0100	0.0000	0.0700	0.0100	0.0400
C1	0.7800	1.4000	1.2700	15.3300	1.1400	3.2200
C2	0.7500	0.9700	2.0800	8.9600	1.6000	2.9500
C3	3.5300	1.3500	4.5700	8.2100	4.0100	6.4800
i-C4	2.0700	1.0500	1.8900	2.3100	2.3400	2.2000
n-C4	6.8800	2.4200	6.4800	4.1900	4.7300	8.5300
i-C5	5.0000	2.7100	3.8800	2.4300	4.1700	4.6800
n-C5	7.4800	3.2900	7.0400	2.3500	2.9700	7.4700
C6	4.1000	4.6900	3.0500	3.1100	4.3800	5.7300
C7	11.3200	11.3500	6.8200	8.4700	8.8100	15.8300
C8	11.7900	12.4100	7.7800	8.8400	12.3800	12.6400
C9	6.1100	9.3100	7.2300	3.7100	5.4900	4.0800
C10+	32.0700	36.0900	37.9300	23.5600	32.1400	18.1600
Benzene	0.1400	1.4000	0.8300	0.8200	2.8900	0.3400
Toluene	0.3800	2.3200	1.0200	4.6700	6.4200	1.0200
E-Benzene	0.2700	0.1600	0.0700	0.0300	0.5700	0.0400
Xylenes	1.0300	4.0200	0.6500	0.3900	3.3000	0.4000
n-C6	5.4200	4.9700	6.1000	2.1300	2.6400	6.1800
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 22**	**Sample Tank No. 23**	**Sample Tank No. 24**	**Sample Tank No. 25**	**Sample Tank No. 26**	**Sample Tank No. 27**
E&P Tank Number	**Tank No. 79**	**Tank No. 80**	**Tank No. 81**	**Tank No. 82**	**Tank No. 83**	**Tank No. 84**
Total Emissions (tpy)	362.298	790.092	557.188	5007.636	175.911	714.052
VOC Emissions (tpy)	175.304	665.349	483.599	3386.300	77.584	639.895
Methane Emissions (tpy)	109.676	24.115	10.288	842.206	54.660	18.553
HAP Emissions (tpy)	**7.150**	**28.770**	**14.580**	**101.610**	**4.770**	**30.190**
Benzene	*0.353*	*3.892*	*1.930*	*9.782*	*0.929*	*4.165*
Toluene	*0.102*	*6.465*	*1.651*	*12.547*	*0.909*	*2.542*
E-Benzene	*0.120*	*0.119*	*0.055*	*0.040*	*0.050*	*0.192*
Xylenes	*0.437*	*2.017*	*0.631*	*0.716*	*0.221*	*1.424*
n-C6	*6.133*	*16.273*	*10.317*	*78.528*	*2.665*	*21.871*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	115	30	15	770	39	38
Separator Temperature (F)	73	100	86	100	66	95
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	73	100	86	100	66	95
C10+ SG	0.873	0.901	0.878	0.858	0.854	0.823
C10+ MW	200	220	254	195	175	375
API Gravity	**54.0**	**54.0**	**54.0**	**55.0**	**57.0**	**57.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	5.30	9.40	10.30	7.80	5.70	9.60
GOR (scf/bbl)	51.34	68.32	47.12	578.20	25.46	57.38
Heating Value of Vapor (Btu/s	1678.80	2676.21	2764.90	2043.18	1632.00	2897.16
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0900	0.1100	0.0200	0.5500	0.0700	0.0400
N2	0.0300	0.0200	0.0100	0.0300	0.0000	0.0000
C1	3.5600	0.7100	0.3300	16.1500	1.7200	0.7000
C2	1.4300	1.5400	1.0900	7.1400	0.9000	1.0900
C3	1.8700	4.5900	3.8300	9.6600	1.3800	3.5600
i-C4	0.6800	2.3400	3.7000	3.8100	1.0000	2.9000
n-C4	2.0000	4.4400	4.8700	5.9600	1.4900	6.2100
i-C5	1.6600	3.9000	4.4800	3.5300	1.4600	6.0400
n-C5	2.0600	3.8000	3.9800	3.7200	1.5300	5.8400
C6	2.4100	5.0900	6.0500	3.8400	4.0600	7.3200
C7	15.0800	12.9700	15.6400	8.7600	14.5700	13.0000
C8	25.1900	19.0700	17.5800	8.9200	23.7200	12.2200
C9	12.4900	6.9500	6.1000	3.1000	13.7700	7.9600
C10+	24.3900	18.9200	21.1300	17.9300	20.9800	20.0200
Benzene	0.2400	1.2000	1.0500	0.5800	1.4900	1.2200
Toluene	0.2100	5.5400	2.6000	2.3000	4.5300	2.0500
E-Benzene	0.6600	0.2500	0.2200	0.0200	0.6700	0.3800
Xylenes	2.7600	4.8300	2.8900	0.4200	3.4200	3.2200
n-C6	3.1900	3.7300	4.4300	3.5800	3.2400	6.2300
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 28	Sample Tank No. 29	Sample Tank No. 30	Sample Tank No. 31	Sample Tank No. 32	Sample Tank No. 33
E&P Tank Number	**Tank No. 85**	**Tank No. 86**	**Tank No. 87**	**Tank No. 88**	**Tank No. 89**	**Tank No. 90**
Total Emissions (tpy)	801.228	983.881	4326.573	3074.670	2951.879	616.490
VOC Emissions (tpy)	757.176	750.313	2406.579	1892.668	1439.584	332.126
Methane Emissions (tpy)	5.307	49.123	1088.727	746.499	999.175	120.918
HAP Emissions (tpy)	**29.510**	**14.080**	**58.180**	**47.230**	**44.040**	**9.140**
Benzene	*3.415*	*1.119*	*4.653*	*5.891*	*1.409*	*0.576*
Toluene	*5.329*	*1.453*	*5.785*	*6.575*	*2.934*	*1.658*
E-Benzene	*0.192*	*0.049*	*0.186*	*0.022*	*0.159*	*0.079*
Xylenes	*1.786*	*0.263*	*0.989*	*0.316*	*1.136*	*0.806*
n-C6	*18.788*	*11.194*	*46.561*	*34.427*	*38.406*	*6.016*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	65	54	870	600	780	60
Separator Temperature (F)	80	60	78	70	70	56
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	80	60	78	70	70	60
C10+ SG	0.899	0.868	0.868	0.847	0.905	0.905
C10+ MW	166	268	268	176	174	174
API Gravity	**57.0**	**57.0**	**57.0**	**57.0**	**58.0**	**58.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.80	13.10	13.10	7.50	8.00	8.00
GOR (scf/bbl)	61.26	97.00	578.20	396.24	436.98	79.54
Heating Value of Vapor (Btu/s	3046.83	2390.47	1789.23	1831.51	1633.60	1851.14
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	0.0800	0.4200	0.5800	0.2700	0.0800
N2	0.0000	0.0000	0.0800	0.0200	0.0200	0.0100
C1	0.1500	1.4800	21.2000	16.0200	20.3000	3.3900
C2	0.5700	2.9100	8.2900	4.1200	5.1800	2.4300
C3	2.4100	6.9600	8.5400	6.9000	5.6800	3.8400
i-C4	1.7300	2.6300	2.3000	2.7500	1.4200	1.3000
n-C4	3.5500	7.2100	5.8400	4.9100	4.1400	3.2000
i-C5	4.1400	4.6400	3.3500	3.6000	2.5400	2.4100
n-C5	3.8600	5.7100	4.0400	3.9000	3.1000	2.5600
C6	6.5100	5.0100	3.4200	3.9500	3.7700	3.7700
C7	18.7100	13.5500	9.1200	10.3800	11.2200	13.2600
C8	19.4300	15.0600	10.0900	11.3000	14.7500	22.4400
C9	6.8400	6.2300	4.1700	4.2100	7.0600	11.1300
C10+	15.5200	18.8400	12.5900	19.2800	13.5400	16.0600
Benzene	1.1800	0.5900	0.4000	0.8200	0.1800	0.4100
Toluene	5.2100	2.5000	1.6800	3.0600	1.2600	3.8600
E-Benzene	0.4600	0.2400	0.1600	0.0300	0.2000	0.5200
Xylenes	4.8600	1.4900	1.0000	0.5000	1.6700	6.1500
n-C6	4.8600	4.8700	3.3100	3.6700	3.7000	3.1800
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 34**	**Sample Tank No. 35**	**Sample Tank No. 36**	**Sample Tank No. 37**	**Sample Tank No. 38**	**Sample Tank No. 39**
E&P Tank Number	**Tank No. 91**	**Tank No. 92**	**Tank No. 93**	**Tank No. 94**	**Tank No. 95**	**Tank No. 96**
Total Emissions (tpy)	2575.122	2774.089	653.459	3495.242	363.650	4744.399
VOC Emissions (tpy)	1494.749	2092.925	394.781	2876.860	223.772	3658.384
Methane Emissions (tpy)	581.208	346.071	121.446	169.818	84.912	381.967
HAP Emissions (tpy)	**65.980**	**48.710**	**14.210**	**93.030**	**10.760**	**89.970**
Benzene	*9.303*	*2.750*	*0.871*	*10.232*	*0.500*	*11.564*
Toluene	*14.114*	*2.311*	*2.688*	*11.558*	*0.279*	*11.735*
E-Benzene	*0.019*	*0.128*	*0.136*	*0.034*	*0.060*	*0.033*
Xylenes	*0.409*	*0.872*	*1.400*	*0.580*	*0.256*	*0.472*
n-C6	*42.130*	*42.650*	*9.111*	*70.629*	*9.661*	*66.162*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	500	300	110	750	85	730
Separator Temperature (F)	84	80	72	90	85	84
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	84	80	72	90	85	84
C10+ SG	0.909	0.882	0.901	0.898	0.9	0.898
C10+ MW	204	296	162	215	202	225
API Gravity	**58.0**	**58.0**	**59.0**	**60.0**	**61.0**	**61.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	9.10	10.60	10.00	9.40	7.00	9.80
GOR (scf/bbl)	323.88	287.10	79.90	320.48	45.04	475.20
Heating Value of Vapor (Btu/s	1892.64	2289.04	1946.32	2541.49	1921.87	2340.56
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.2300	0.0300	0.0800	0.3400	0.0400	0.4100
N2	0.0600	0.0900	0.0100	0.0200	0.0200	0.0300
C1	12.9800	8.4300	3.3900	3.7500	2.6100	7.3900
C2	5.7800	4.2300	2.4300	4.7700	1.1600	6.6400
C3	4.6400	5.9100	3.8400	9.2600	2.2100	10.9400
i-C4	2.0900	5.1700	1.3000	4.8100	0.9300	4.5800
n-C4	4.1800	6.2200	3.2000	7.0200	2.4900	8.3400
i-C5	4.9600	8.9100	2.4100	5.5900	2.1300	5.5000
n-C5	4.0700	4.9700	2.5600	6.1200	2.9200	5.8200
C6	6.0700	9.1100	3.7700	6.1300	3.5400	5.3200
C7	13.1100	11.3400	13.2600	12.8200	19.5300	11.2900
C8	11.9500	10.3900	22.4400	12.5200	27.1600	11.1800
C9	4.8600	5.9600	11.1300	4.0100	14.7000	3.1900
C10+	14.1100	11.7500	16.0600	11.4200	13.8800	8.8000
Benzene	1.1400	0.3700	0.4100	1.1000	0.2900	1.1400
Toluene	5.4100	0.9800	3.8600	3.7900	0.4700	3.7600
E-Benzene	0.0200	0.1500	0.5200	0.0300	0.2600	0.0300
Xylenes	0.5000	1.1900	6.1500	0.5900	1.2600	0.5000
n-C6	3.8400	4.8000	3.1800	5.9100	4.4000	5.1400
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 40**	**Sample Tank No. 41**	**Sample Tank No. 42**	**Sample Tank No. 43**	**Sample Tank No. 44**	**Sample Tank No. 45**
E&P Tank Number	**Tank No. 97**	**Tank No. 98**	**Tank No. 99**	**Tank No. 100**	**Tank No. 101**	**Tank No. 102**
Total Emissions (tpy)	907.495	277.197	3410.034	2122.607	8152.118	6780.555
VOC Emissions (tpy)	734.651	158.333	2732.261	1066.705	5678.554	4276.160
Methane Emissions (tpy)	49.578	75.426	159.904	736.341	1206.981	1045.765
HAP Emissions (tpy)	**24.160**	**8.820**	**67.500**	**64.680**	**81.710**	**48.890**
Benzene	*1.573*	*0.204*	*9.290*	*9.500*	*10.844*	*5.934*
Toluene	*3.102*	*0.854*	*9.192*	*15.007*	*8.516*	*1.416*
E-Benzene	*0.094*	*0.042*	*0.016*	*0.161*	*0.012*	*0.222*
Xylenes	*1.079*	*0.375*	*0.371*	*1.585*	*0.288*	*1.359*
n-C6	*18.314*	*7.344*	*48.628*	*38.425*	*62.050*	*39.961*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	57	72	730	580	730	807
Separator Temperature (F)	82	80	80	77	80	96
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	82	80	80	77	80	96
C10+ SG	0.884	0.869	0.883	0.85	0.895	0.811
C10+ MW	240	190	226	190	197	173
API Gravity	**62.0**	**63.0**	**63.0**	**64.0**	**64.0**	**66.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.40	7.00	11.90	6.40	11.00	11.80
GOR (scf/bbl)	84.20	36.56	321.62	309.64	924.96	804.54
Heating Value of Vapor (Btu/s	2521.70	1805.12	2477.18	1622.20	2083.02	2013.21
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0800	0.0400	0.3200	0.0700	0.5600	0.2200
N2	0.0100	0.0300	0.0200	0.0700	0.0300	0.0800
C1	1.4000	2.3500	3.4800	16.3500	16.9100	16.2600
C2	1.7700	1.0000	5.5300	3.6400	8.6200	11.7100
C3	4.8200	2.0700	10.1700	3.5600	12.0400	11.6100
i-C4	2.8200	0.7100	4.9900	1.6900	5.2700	4.3900
n-C4	5.9700	2.2600	8.1400	2.9800	9.0700	7.5600
i-C5	4.3100	1.7000	5.8700	2.6800	5.6500	4.5200
n-C5	4.1900	2.7400	6.1600	2.7900	5.8200	3.9400
C6	6.5100	3.4900	5.7200	3.8200	5.1000	3.3600
C7	17.7500	17.7300	12.3800	18.1400	8.0600	5.9200
C8	18.6400	27.9100	12.3100	19.4700	7.5500	11.6900
C9	7.4400	16.1500	3.7900	4.5900	2.2200	5.9200
C10+	11.6100	12.2800	9.9100	6.7300	5.6700	8.9300
Benzene	0.5600	0.1600	1.2800	1.2200	0.8500	0.3700
Toluene	3.2800	1.9800	4.0500	6.0700	2.3800	0.3000
E-Benzene	0.2600	0.2500	0.0200	0.1800	0.0100	0.1400
Xylenes	3.4100	2.5800	0.5300	2.0600	0.2900	1.0100
n-C6	5.1700	4.5700	5.3300	3.8900	3.9000	2.0700
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 46	Sample Tank No. 47	Sample Tank No. 48	Sample Tank No. 49	Sample Tank No. 50	Sample Tank No. 51
E&P Tank Number	**Tank No. 103**	**Tank No. 1**	**Tank No. 2**	**Tank No. 3**	**Tank No. 4**	**Tank No. 5**
Total Emissions (tpy)	927.902	95.816	112.738	74.503	155.244	93.073
VOC Emissions (tpy)	623.038	6.175	61.936	28.446	61.470	51.471
Methane Emissions (tpy)	167.129	0.115	1.927	0.309	46.064	0.440
HAP Emissions (tpy)	**20.320**	**0.460**	**2.960**	**0.990**	**1.760**	**3.190**
Benzene	*1.625*	*0.006*	*0.076*	*0.012*	*0.010*	*0.218*
Toluene	*1.876*	*0.013*	*0.060*	*0.031*	*0.037*	*0.074*
E-Benzene	*0.062*	*0.007*	*0.019*	*0.002*	*0.025*	*0.006*
Xylenes	*0.696*	*0.018*	*0.105*	*0.041*	*0.069*	*0.048*
n-C6	*16.059*	*0.421*	*2.704*	*0.904*	*1.616*	*2.845*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	170	45	22	20	53	15
Separator Temperature (F)	75	106	155	160	101	120
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	75	106	155	160	101	120
C10+ SG	0.801	0.972	0.972	0.952	0.961	0.984
C10+ MW	196	425	436	458	394	551
API Gravity	**68.0**	**15.0**	**17.0**	**18.0**	**19.0**	**19.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	12.50	0.80	2.00	0.60	2.30	4.80
GOR (scf/bbl)	106.60	8.88	9.60	6.44	17.78	7.52
Heating Value of Vapor (Btu/s	2081.33	181.43	1738.61	1076.97	1365.68	1718.17
LP Oil Component						
H2S	0.0000	0.1100	0.0000	0.0400	0.5100	0.1400
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	2.8500	1.3000	1.5400	1.1900	1.5000
N2	0.0100	0.0000	0.0000	0.0300	0.0100	0.0000
C1	4.9300	0.0100	0.1500	0.0300	1.5300	0.0400
C2	2.5800	0.0100	0.4000	0.0400	0.5300	0.2400
C3	3.4200	0.0200	0.7800	0.2200	0.8100	0.8500
i-C4	3.4300	0.0500	0.5600	0.1600	0.5000	0.6500
n-C4	3.7300	0.1800	1.2600	0.4700	1.2000	1.6500
i-C5	5.5500	0.3200	0.8700	0.4300	1.1500	2.1900
n-C5	3.6500	0.4500	1.2400	0.6500	1.3400	3.1500
C6	8.0700	0.6000	1.9800	0.6100	1.7500	4.7300
C7	14.6500	1.7200	3.4500	1.5800	3.6200	6.2500
C8	13.2600	2.1800	4.2600	2.0700	3.5300	10.2800
C9	7.8000	1.8400	3.6600	2.2800	3.5300	5.9300
C10+	19.6300	88.7100	78.1500	88.9700	76.8100	57.9100
Benzene	0.5400	0.0100	0.0500	0.0100	0.0100	0.3000
Toluene	1.9200	0.0600	0.0900	0.0600	0.1000	0.2600
E-Benzene	0.1700	0.0800	0.0600	0.0100	0.1600	0.0500
Xylenes	2.2200	0.2300	0.3700	0.1800	0.5100	0.4300
n-C6	4.4300	0.5700	1.3700	0.6200	1.2100	3.4500
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 52	Sample Tank No. 53	Sample Tank No. 54	Sample Tank No. 55	Sample Tank No. 56	Sample Tank No. 57
E&P Tank Number	**Tank No. 6**	**Tank No. 7**	**Tank No. 8**	**Tank No. 9**	**Tank No. 10**	**Tank No. 11**
Total Emissions (tpy)	24.484	26.091	29.739	114.630	42.075	
VOC Emissions (tpy)	3.087	17.629	11.288	74.707	8.263	
Methane Emissions (tpy)	15.587	2.836	5.908	25.400	27.176	
HAP Emissions (tpy)	**0.190**	**0.510**	**0.330**	**2.120**	**0.090**	
Benzene	*0.003*	*0.007*	*0.013*	*0.039*	*0.028*	
Toluene	*0.006*	*0.014*	*0.008*	*0.071*	*0.010*	
E-Benzene	*0.000*	*0.001*	*0.003*	*0.007*	*0.000*	
Xylenes	*0.005*	*0.012*	*0.007*	*0.090*	*0.001*	
n-C6	*0.175*	*0.474*	*0.298*	*1.919*	*0.052*	
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	
Separator Pressure (psig)	23	17	18	54	35	
Separator Temperature (F)	79	106	75	125	76	
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	
Ambient Temperature (F)	79	106	75	125	76	
C10+ SG	0.947	0.967	0.963	0.943	0.923	
C10+ MW	368	383	401	363	278	
API Gravity	**20.0**	**20.0**	**20.0**	**21.0**	**23.0**	
Production Rate (bbl/day)	500	500	500	500	500	
Reid Vapor Pressure (psia)	1.20	3.30	3.80	1.10	1.80	
GOR (scf/bbl)	4.98	2.82	3.94	13.90	8.52	
Heating Value of Vapor (Btu/s	1067.32	2208.23	1236.41	1980.20	1192.63	
LP Oil Component						
H2S	0.0100	0.0000	0.0000	0.0000	0.0000	
O2	0.0000	0.0000	0.0000	0.0000	0.0000	
CO2	0.0700	0.0000	0.2500	0.0000	0.0600	
N2	0.0900	0.0000	0.2100	0.0100	0.0100	
C1	1.2500	0.1900	0.5300	1.8000	1.7700	
C2	0.2000	0.2300	0.3300	0.5400	0.2900	
C3	0.0800	0.7500	0.7500	0.5200	0.3700	
i-C4	0.0900	0.4900	0.4900	0.2800	0.2300	
n-C4	0.1800	1.5700	1.5000	0.9200	0.3100	
i-C5	0.4000	1.5300	1.3500	0.9800	0.4900	
n-C5	0.4500	1.9100	1.7700	0.9700	0.2400	
C6	1.0500	2.7500	2.3700	1.6800	0.2500	
C7	2.3300	3.9000	4.3000	3.0100	0.5900	
C8	2.9800	6.8100	5.5200	3.7300	0.5000	
C9	2.6000	4.0100	3.5700	3.5400	0.2500	
C10+	87.0300	73.0300	74.2800	80.2500	94.2100	
Benzene	0.0200	0.0400	0.1000	0.0300	0.1100	
Toluene	0.1100	0.2200	0.1900	0.1400	0.1200	
E-Benzene	0.0200	0.0500	0.1900	0.0300	0.0100	
Xylenes	0.2700	0.5100	0.4700	0.4500	0.0500	
n-C6	0.7700	2.0100	1.8300	1.1200	0.1400	
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	
	100.0000	100.0000	100.0000	100.0000	100.0000	0.0000

Tank ID	Sample Tank No. 58	Sample Tank No. 59	Sample Tank No. 60	Sample Tank No. 61	Sample Tank No. 62	Sample Tank No. 63
E&P Tank Number	**Tank No. 12**	**Tank No. 13**	**Tank No. 14**	**Tank No. 15**	**Tank No. 16**	**Tank No. 17**
Total Emissions (tpy)	134.719	26.214	195.573	142.068	191.224	35.095
VOC Emissions (tpy)	63.729	5.207	109.615	69.135	105.838	25.578
Methane Emissions (tpy)	16.689	12.924	7.759	5.438	4.313	3.029
HAP Emissions (tpy)	**1.170**	**0.430**	**2.810**	**1.760**	**2.110**	**0.750**
Benzene	*0.020*	*0.008*	*0.033*	*0.024*	*0.041*	*0.011*
Toluene	*0.014*	*0.032*	*0.032*	*0.053*	*0.079*	*0.022*
E-Benzene	*0.007*	*0.002*	*0.023*	*0.003*	*0.003*	*0.003*
Xylenes	*0.027*	*0.019*	*0.064*	*0.041*	*0.016*	*0.011*
n-C6	*1.104*	*0.371*	*2.659*	*1.640*	*1.969*	*0.701*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	30	20	20	22	20	19
Separator Temperature (F)	66	122	88	86	68	133
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	66	122	88	86	68	133
C10+ SG	0.946	0.926	0.945	0.944	0.964	0.928
C10+ MW	382	336	381	404	444	327
API Gravity	**23.0**	**24.0**	**24.0**	**24.0**	**24.0**	**25.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.00	0.60	3.90	4.60	4.80	4.10
GOR (scf/bbl)	15.42	4.60	19.12	13.74	17.84	3.48
Heating Value of Vapor (Btu/s	1553.86	1059.39	1747.39	1543.44	1703.42	2314.31
LP Oil Component						
H2S	0.4400	0.0000	0.5200	0.4500	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.6400	0.1200	0.9600	1.1500	1.4200	0.0500
N2	0.0100	0.1000	0.1200	0.0200	0.0200	0.0000
C1	1.0700	0.9400	0.4900	0.3600	0.2700	0.2500
C2	0.5400	0.0500	0.6500	0.5000	0.6200	0.4900
C3	1.4100	0.0700	1.7300	1.5900	1.9400	1.1600
i-C4	0.7000	0.0600	0.7400	0.7600	1.1000	0.6000
n-C4	1.9400	0.1000	2.4600	2.4000	3.0100	1.5900
i-C5	1.8900	0.2400	1.7900	1.7300	2.1900	1.4300
n-C5	2.3600	0.2300	2.3100	2.1400	3.2100	1.4400
C6	2.7100	0.9100	2.6100	2.6400	3.9300	1.9900
C7	5.1800	2.8000	5.3300	5.5200	5.6800	3.5100
C8	5.3700	4.2200	5.5400	6.0700	11.3000	4.4100
C9	3.9800	4.3400	4.2100	4.6000	6.7600	4.4400
C10+	68.6500	84.5400	67.0700	66.9000	54.5000	76.8100
Benzene	0.0500	0.0200	0.0400	0.0400	0.0800	0.0300
Toluene	0.1100	0.2100	0.1100	0.2600	0.4700	0.1500
E-Benzene	0.1500	0.0300	0.2000	0.0400	0.0400	0.0400
Xylenes	0.6500	0.3100	0.6300	0.5800	0.2900	0.1800
n-C6	2.1500	0.7100	2.4900	2.2500	3.1700	1.4300
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 64**	**Sample Tank No. 65**	**Sample Tank No. 66**	**Sample Tank No. 67**	**Sample Tank No. 68**	**Sample Tank No. 69**
E&P Tank Number	**Tank No. 18**	**Tank No. 19**	**Tank No. 20**	**Tank No. 21**	**Tank No. 22**	**Tank No. 23**
Total Emissions (tpy)	139.887	70.761	171.538	38.394	215.631	148.757
VOC Emissions (tpy)	89.426	46.290	110.120	12.834	164.956	138.780
Methane Emissions (tpy)	21.590	4.142	15.382	16.424	8.875	1.515
HAP Emissions (tpy)	**1.190**	**2.570**	**1.670**	**0.720**	**4.240**	**5.310**
Benzene	*0.011*	*0.371*	*0.013*	*0.224*	*0.985*	*1.086*
Toluene	*0.035*	*0.697*	*0.017*	*0.209*	*0.787*	*0.854*
E-Benzene	*0.010*	*0.039*	*0.004*	*0.007*	*0.020*	*0.025*
Xylenes	*0.025*	*0.176*	*0.025*	*0.066*	*0.118*	*0.122*
n-C6	*1.109*	*1.292*	*1.613*	*0.216*	*2.331*	*3.227*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	30	25	31	23	17	20
Separator Temperature (F)	60	136	64	79	86	120
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	136	64	79	86	120
C10+ SG	0.94	0.916	0.938	0.908	0.946	0.932
C10+ MW	380	431	340	324	323	326
API Gravity	**25.0**	**27.0**	**27.0**	**29.0**	**29.0**	**29.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.90	3.30	5.20	3.10	4.80	4.90
GOR (scf/bbl)	16.66	6.76	18.46	6.36	20.11	11.50
Heating Value of Vapor (Btu/s	1966.88	2041.97	1887.18	1405.21	2354.30	2985.81
LP Oil Component						
H2S	0.0000	0.3800	0.2400	0.0000	0.2700	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0600	0.2200	0.2100	0.0900	0.0800	0.0300
N2	0.0400	0.1000	0.3000	0.0000	0.0000	0.0000
C1	1.3500	0.3200	0.8600	1.1200	0.4400	0.0800
C2	0.8500	0.4100	0.5400	0.5300	0.7000	0.2000
C3	2.0900	1.0700	1.7500	0.7000	2.0600	1.3000
i-C4	1.1400	0.5700	1.1600	0.4500	0.9700	1.0400
n-C4	2.7100	1.4500	3.1500	0.6300	2.7500	3.8800
i-C5	2.1900	1.5700	2.9100	0.6400	2.7000	2.2100
n-C5	2.4600	1.5100	2.5900	0.4600	2.3200	3.2000
C6	2.2400	2.5400	3.7200	0.8400	3.5000	2.5500
C7	5.7900	3.5300	5.8600	4.7900	8.3100	7.2000
C8	4.7900	4.9600	5.6200	8.9000	7.2900	7.2300
C9	4.4800	4.1700	3.7300	5.8000	7.0500	4.7500
C10+	66.3000	72.0600	63.8500	67.7100	53.9500	59.2600
Benzene	0.0300	0.4300	0.0300	1.0000	1.2400	1.1600
Toluene	0.2900	1.9600	0.1200	2.7600	2.8500	2.3500
E-Benzene	0.2200	0.2400	0.0800	0.2400	0.1800	0.1600
Xylenes	0.6500	1.2100	0.5400	2.5900	1.2300	0.8600
n-C6	2.3200	1.3000	2.7400	0.7500	2.1100	2.5400
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 70**	**Sample Tank No. 71**	**Sample Tank No. 72**	**Sample Tank No. 73**	**Sample Tank No. 74**	**Sample Tank No. 75**
E&P Tank Number	**Tank No. 24**	**Tank No. 25**	**Tank No. 26**	**Tank No. 27**	**Tank No. 28**	**Tank No. 29**
Total Emissions (tpy)	243.873	502.831	13.397	154.387	119.805	263.134
VOC Emissions (tpy)	151.292	330.274	4.231	125.001	48.333	168.558
Methane Emissions (tpy)	7.881	124.465	6.395	4.603	45.716	54.016
HAP Emissions (tpy)	**2.480**	**13.120**	**0.070**	**10.900**	**1.090**	**3.440**
Benzene	*0.188*	*0.954*	*0.008*	*0.053*	*0.189*	*0.435*
Toluene	*0.276*	*1.256*	*0.003*	*0.110*	*0.076*	*0.413*
E-Benzene	*0.007*	*0.086*	*0.000*	*0.031*	*0.004*	*0.046*
Xylenes	*0.114*	*0.732*	*0.008*	*0.305*	*0.033*	*0.285*
n-C6	*1.896*	*10.096*	*0.055*	*10.401*	*0.785*	*2.257*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	22	280	4	25	64	80
Separator Temperature (F)	98	106	80	180	70	77
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	98	106	80	180	70	77
C10+ SG	0.917	0.921	0.893	0.916	0.898	0.896
C10+ MW	311	450	313	304	368	309
API Gravity	**29.0**	**30.0**	**30.0**	**30.0**	**30.0**	**33.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	6.20	4.80	2.60	2.70	2.80	2.20
GOR (scf/bbl)	24.26	61.80	2.34	11.76	18.78	32.78
Heating Value of Vapor (Btu/s	2141.84	1933.26	1394.74	2814.20	1478.45	1920.70
LP Oil Component						
H2S	1.0100	0.0000	0.0000	0.0300	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.1100	0.1200	0.0200	0.2700	0.1700	0.0300
N2	0.0000	0.0500	0.0000	0.0000	0.0200	0.0200
C1	0.4000	7.9800	0.5900	0.2600	3.1300	2.9000
C2	1.6600	1.5600	0.4000	0.4800	0.7000	1.1000
C3	2.2300	2.8200	0.5500	0.8100	1.0700	1.7100
i-C4	1.1500	1.4300	0.4500	0.3600	0.8800	1.0700
n-C4	1.9500	2.4400	0.6300	1.1800	1.1100	1.1500
i-C5	2.8400	2.1200	0.4800	1.2900	1.0500	1.5000
n-C5	1.3600	2.0900	0.4500	2.0600	1.0000	1.2300
C6	3.0700	2.5400	1.0000	2.6800	1.5300	2.3300
C7	6.9000	6.3500	4.3100	6.5200	4.4300	6.0000
C8	7.6500	8.0300	4.9000	7.3900	5.8900	8.7700
C9	5.8200	3.5600	4.1700	4.8600	4.2200	6.3100
C10+	61.2100	54.9600	80.5100	68.2000	72.4400	60.3600
Benzene	0.1500	0.2000	0.0900	0.0200	0.3100	0.3800
Toluene	0.6100	0.6800	0.1100	0.0900	0.3800	1.0700
E-Benzene	0.0400	0.1100	0.0200	0.0500	0.0500	0.3100
Xylenes	0.7000	1.0600	0.8100	0.5400	0.5000	2.2000
n-C6	1.1400	1.9000	0.5100	2.9100	1.1200	1.5600
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 76	Sample Tank No. 77	Sample Tank No. 78	Sample Tank No. 79	Sample Tank No. 80	Sample Tank No. 81
E&P Tank Number	**Tank No. 30**	**Tank No. 31**	**Tank No. 32**	**Tank No. 33**	**Tank No. 34**	**Tank No. 35**
Total Emissions (tpy)	75.697	67.111	33.481	98.139	246.837	206.565
VOC Emissions (tpy)	48.997	21.176	9.640	41.538	186.576	136.694
Methane Emissions (tpy)	15.026	39.198	18.906	45.393	13.777	5.258
HAP Emissions (tpy)	**1.330**	**0.460**	**0.290**	**1.230**	**7.150**	**4.120**
Benzene	*0.115*	*0.055*	*0.025*	*0.118*	*1.477*	*0.060*
Toluene	*0.088*	*0.025*	*0.040*	*0.085*	*1.336*	*0.122*
E-Benzene	*0.010*	*0.002*	*0.004*	*0.008*	*0.030*	*0.010*
Xylenes	*0.038*	*0.011*	*0.023*	*0.165*	*0.263*	*0.100*
n-C6	*1.075*	*0.362*	*0.196*	*0.852*	*4.047*	*3.833*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	20	60	18	40	18	15
Separator Temperature (F)	115	78	70	110	80	108
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	115	78	70	110	80	108
C10+ SG	0.885	0.866	0.875	0.87	0.923	0.887
C10+ MW	280	324	277	297	346	272
API Gravity	**33.0**	**34.0**	**34.0**	**34.0**	**35.0**	**35.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.10	2.00	2.20	3.20	4.70	4.50
GOR (scf/bbl)	8.96	12.60	6.20	16.18	24.36	18.78
Heating Value of Vapor (Btu/s	1989.27	1308.40	1280.62	1473.81	2361.43	2135.62
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0100	0.0500
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0300	0.0500	0.0700	0.0400	0.0600	0.6100
N2	0.0000	0.0000	0.0000	0.0100	0.0100	0.0500
C1	0.8400	2.8100	1.1600	2.9100	0.6400	0.2600
C2	0.3700	0.3100	0.2400	0.4400	1.0500	0.7800
C3	0.9200	0.6200	0.4900	0.6800	2.2200	1.7400
i-C4	1.0000	0.4700	0.4300	0.5800	0.8300	0.8400
n-C4	1.3200	0.7300	0.6500	0.6300	2.7600	2.3700
i-C5	1.3500	0.7100	0.8000	0.5300	2.1100	2.2400
n-C5	1.2200	0.6600	0.7000	0.4900	3.1100	2.2500
C6	1.8500	1.0800	1.2900	0.8900	3.5800	3.1500
C7	4.6800	2.3500	3.6200	4.6300	11.4200	6.1800
C8	5.5400	2.9600	5.5500	5.3100	11.2400	6.7100
C9	3.8000	1.9300	3.8000	4.5800	8.3200	5.0700
C10+	74.8700	84.1900	78.1200	76.3800	40.2000	64.3300
Benzene	0.1700	0.1100	0.1400	0.1000	1.6600	0.0500
Toluene	0.3400	0.1500	0.6900	0.1900	4.4100	0.2700
E-Benzene	0.0900	0.0300	0.1800	0.0400	0.2500	0.0500
Xylenes	0.3900	0.2000	1.2000	0.9800	2.5500	0.5900
n-C6	1.2200	0.6400	0.8700	0.5900	3.5700	2.4100
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 82**	**Sample Tank No. 83**	**Sample Tank No. 84**	**Sample Tank No. 85**	**Sample Tank No. 86**	**Sample Tank No. 87**
E&P Tank Number	**Tank No. 36**	**Tank No. 37**	**Tank No. 38**	**Tank No. 39**	**Tank No. 40**	**Tank No. 41**
Total Emissions (tpy)	176.370	34.019	82.578	113.253	204.693	178.190
VOC Emissions (tpy)	121.493	16.601	32.683	56.649	107.904	100.629
Methane Emissions (tpy)	10.526	12.380	40.189	30.738	57.039	28.323
HAP Emissions (tpy)	**3.520**	**1.050**	**1.820**	**2.310**	**3.540**	**2.460**
Benzene	*0.068*	*0.262*	*0.364*	*0.285*	*0.530*	*0.307*
Toluene	*0.092*	*0.297*	*0.293*	*0.292*	*0.386*	*0.280*
E-Benzene	*0.019*	*0.011*	*0.016*	*0.018*	*0.030*	*0.012*
Xylenes	*0.072*	*0.048*	*0.125*	*0.138*	*0.208*	*0.068*
n-C6	*3.266*	*0.435*	*1.023*	*1.573*	*2.383*	*1.789*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	17	30	50	57	75	28
Separator Temperature (F)	100	125	68	80	81	60
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	100	125	68	80	81	60
C10+ SG	0.887	0.863	0.879	0.883	0.883	0.891
C10+ MW	283	276	356	294	288	277
API Gravity	**35.0**	**36.0**	**36.0**	**36.0**	**36.0**	**36.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.90	2.50	3.80	3.90	4.10	3.80
GOR (scf/bbl)	17.62	5.02	14.02	15.52	27.84	22.04
Heating Value of Vapor (Btu/s	2307.25	1616.36	1437.32	1721.01	1718.90	1846.39
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.2000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0900	0.0300	0.0300	0.0600	0.1400	0.0600
N2	0.0100	0.0000	0.0100	0.0100	0.0100	0.0100
C1	0.5300	0.9100	2.4200	1.5900	2.9000	1.3300
C2	1.1100	0.3200	0.4500	0.7200	0.9500	0.9300
C3	1.7600	0.5700	0.8100	1.1100	1.4500	1.7200
i-C4	0.8000	0.3900	0.5400	0.7700	1.0000	0.4400
n-C4	2.3800	0.5800	1.1700	1.6000	1.8400	1.9800
i-C5	2.1600	0.6500	1.3400	1.5200	1.6700	1.2300
n-C5	2.6700	0.5700	1.6000	1.6700	1.7900	2.2100
C6	3.3700	1.0700	2.4800	2.5900	2.1500	2.4300
C7	6.0700	3.3600	7.6400	7.1400	6.1000	9.4100
C8	6.8700	5.7300	10.3500	9.7000	7.9700	10.5500
C9	6.0400	4.2600	5.9100	5.1000	5.2600	6.0500
C10+	62.5300	77.9200	57.3100	59.8700	61.4100	54.5600
Benzene	0.0700	0.5500	0.8300	0.5000	0.5100	0.6300
Toluene	0.2600	1.5800	2.0500	1.5100	1.0900	1.8200
E-Benzene	0.1300	0.1300	0.2900	0.2400	0.2200	0.2100
Xylenes	0.5600	0.6500	2.6900	2.1000	1.7300	1.4100
n-C6	2.5900	0.7300	2.0800	2.2000	1.8100	2.8200
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 88**	**Sample Tank No. 89**	**Sample Tank No. 90**	**Sample Tank No. 91**	**Sample Tank No. 92**	**Sample Tank No. 93**
E&P Tank Number	**Tank No. 42**	**Tank No. 43**	**Tank No. 44**	**Tank No. 45**	**Tank No. 46**	**Tank No. 47**
Total Emissions (tpy)	264.744	77.810	341.571	746.422	120.452	114.826
VOC Emissions (tpy)	197.667	45.796	126.289	598.797	71.033	53.659
Methane Emissions (tpy)	4.156	20.047	121.935	12.450	24.855	41.873
HAP Emissions (tpy)	**5.070**	**1.720**	**2.060**	**7.990**	**1.310**	**1.960**
Benzene	*0.536*	*0.269*	*0.294*	*3.587*	*0.126*	*0.496*
Toluene	*6.120*	*0.232*	*0.161*	*0.449*	*0.199*	*0.291*
E-Benzene	*0.040*	*0.014*	*0.036*	*0.061*	*0.009*	*0.009*
Xylenes	*0.205*	*0.121*	*0.106*	*0.072*	*0.077*	*0.052*
n-C6	*3.677*	*1.081*	*1.462*	*3.820*	*0.900*	*1.109*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	18	18	190	22	24	60
Separator Temperature (F)	95	98	70	50	68	72
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	95	98	70	50	68	72
C10+ SG	0.9	0.871	0.861	0.918	0.872	0.863
C10+ MW	288	270	270	372	239	318
API Gravity	**36.0**	**37.0**	**37.0**	**37.0**	**38.0**	**38.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	7.20	3.90	3.00	4.90	3.60	4.50
GOR (scf/bbl)	23.68	10.02	53.74	67.22	15.46	17.44
Heating Value of Vapor (Btu/s	2352.89	1820.80	1489.35	2491.03	1867.10	1590.85
LP Oil Component						
H2S	0.8700	0.0000	0.0000	0.1400	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.1200	0.0500	0.3100	0.5300	0.0200	0.0500
N2	0.0200	0.0000	0.0300	0.0000	0.0000	0.0000
C1	0.1900	1.0400	6.2500	0.5600	1.1400	2.5500
C2	0.6800	0.4200	2.2000	2.3100	0.5800	0.8600
C3	2.5400	0.9700	2.0200	4.1000	1.2600	1.3500
i-C4	1.1400	1.1500	0.5500	1.9100	0.9300	0.9700
n-C4	3.8100	1.3100	1.1800	5.0000	1.4400	1.3600
i-C5	2.9900	1.6600	0.8300	3.4000	1.6100	1.4200
n-C5	2.9100	1.2800	0.7100	3.5100	1.3900	1.3400
C6	3.7100	2.1200	1.3200	3.0200	2.3200	2.1100
C7	9.0500	5.2700	3.8300	13.2800	6.5000	5.5300
C8	7.1100	7.7200	6.7800	13.1300	8.7200	7.6500
C9	5.9500	4.7200	2.8000	5.9600	5.9100	5.6600
C10+	52.8400	67.1300	69.1900	36.1900	62.7500	64.2400
Benzene	0.4700	0.5000	0.1800	2.6100	0.3100	0.8400
Toluene	1.5000	1.1900	0.3000	1.0600	1.5000	1.4900
E-Benzene	0.2400	0.1800	0.1800	0.4000	0.1800	0.1200
Xylenes	1.4100	1.7200	0.6100	0.5500	1.7900	0.8100
n-C6	2.4500	1.5700	0.7300	2.3400	1.6500	1.6500
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 94	Sample Tank No. 95	Sample Tank No. 96	Sample Tank No. 97	Sample Tank No. 98	Sample Tank No. 99
E&P Tank Number	**Tank No. 48**	**Tank No. 49**	**Tank No. 50**	**Tank No. 51**	**Tank No. 52**	**Tank No. 53**
Total Emissions (tpy)	54.705	437.309	165.905	279.758	608.810	254.487
VOC Emissions (tpy)	37.588	181.269	149.208	103.605	571.582	161.927
Methane Emissions (tpy)	8.963	1.079	0.600	12.141	8.030	48.433
HAP Emissions (tpy)	**2.550**	**4.660**	**4.640**	**1.630**	**17.380**	**7.830**
Benzene	*0.263*	*0.041*	*0.202*	*0.453*	*0.424*	*2.228*
Toluene	*0.317*	*0.110*	*0.380*	*0.085*	*0.458*	*1.268*
E-Benzene	*0.024*	*0.053*	*0.035*	*0.015*	*0.025*	*0.039*
Xylenes	*0.218*	*0.149*	*0.168*	*0.017*	*0.441*	*0.399*
n-C6	*1.726*	*4.311*	*3.855*	*1.063*	*16.032*	*3.892*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	32	62	13	28	22	66
Separator Temperature (F)	149	80	113	45	114	89
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	149	80	113	45	114	89
C10+ SG	0.862	0.894	0.882	0.904	0.877	0.877
C10+ MW	251	310	294	294	337	282
API Gravity	**38.0**	**38.0**	**38.0**	**38.0**	**38.0**	**39.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.00	5.20	5.70	7.40	3.10	3.70
GOR (scf/bbl)	5.82	37.60	13.60	28.24	45.82	30.08
Heating Value of Vapor (Btu/s	2216.65	1206.29	2853.46	1313.43	3053.30	1945.58
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	4.1200	0.0100	2.0000	0.0400	0.1800
N2	0.0000	0.0200	0.0000	0.0000	0.2000	0.0000
C1	0.5100	0.0500	0.0300	0.5300	0.4200	2.2600
C2	0.4400	0.3200	0.4500	1.0400	0.5700	0.8400
C3	0.5900	1.4800	2.4200	1.9800	2.1600	1.4800
i-C4	0.5400	0.8700	1.1900	1.4200	1.1400	1.0300
n-C4	0.6500	3.3500	3.2300	3.7800	4.2600	1.6000
i-C5	1.3500	3.0800	2.0600	2.9700	2.9000	2.0600
n-C5	1.1500	2.8200	3.0500	2.9500	4.2900	1.8600
C6	2.5000	4.7100	2.3400	2.6800	3.5200	3.4100
C7	6.4600	10.0400	7.7900	11.8900	10.3400	8.6400
C8	8.5600	11.8100	8.3700	11.7900	9.9300	11.0300
C9	3.4500	6.4100	6.4400	6.6500	4.4300	5.1000
C10+	69.3200	46.8100	57.0400	45.6300	51.0200	51.2400
Benzene	0.3200	0.0300	0.2000	1.1100	0.1100	1.6600
Toluene	0.9100	0.2400	0.9900	0.7100	0.3100	2.6900
E-Benzene	0.1500	0.3000	0.2100	0.3600	0.0400	0.2100
Xylenes	1.4800	0.9700	1.1500	0.4800	0.7800	2.4200
n-C6	1.6100	2.5700	3.0300	2.0300	3.5400	2.2900
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 100**	**Sample Tank No. 101**	**Sample Tank No. 102**	**Sample Tank No. 103**
E&P Tank Number	**Tank No. 54**	**Tank No. 55**	**Tank No. 56**	**Tank No. 57**
Total Emissions (tpy)	173.095	363.718	391.465	274.631
VOC Emissions (tpy)	97.629	237.995	191.567	204.825
Methane Emissions (tpy)	52.151	56.163	3.830	22.453
HAP Emissions (tpy)	**4.410**	**2.820**	**5.090**	**19.640**
Benzene	*0.242*	*0.369*	*0.970*	*5.674*
Toluene	*0.281*	*0.045*	*0.836*	*4.267*
E-Benzene	*0.031*	*0.026*	*0.019*	*0.070*
Xylenes	*0.164*	*0.129*	*0.135*	*0.436*
n-C6	*3.689*	*2.253*	*3.127*	*9.194*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	60	60	33	42
Separator Temperature (F)	80	58	60	110
Ambient Pressure (psia)	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	58	60	110
C10+ SG	0.891	0.877	0.907	0.879
C10+ MW	265	309	295	283
API Gravity	**39.0**	**39.0**	**39.0**	**39.0**
Production Rate (bbl/day)	500	500	500	500
Reid Vapor Pressure (psia)	5.60	6.80	6.40	5.40
GOR (scf/bbl)	23.36	43.14	36.04	26.60
Heating Value of Vapor (Btu/s	1766.66	2016.56	1509.76	2428.31
LP Oil Component				
H2S	0.0000	0.0000	0.1100	0.0000
O2	0.0000	0.0000	0.0000	0.0000
CO2	0.0500	0.0300	2.4000	0.0100
N2	0.0100	0.0100	0.0000	0.0000
C1	2.3200	2.6700	0.1600	1.0900
C2	0.7200	1.7300	0.7600	1.5000
C3	1.1900	3.6000	2.6400	2.1200
i-C4	0.8900	1.8800	0.9100	0.8400
n-C4	1.8300	3.2300	3.5800	2.2800
i-C5	2.3500	2.4900	2.6500	1.6400
n-C5	3.2400	2.1100	3.4400	2.5200
C6	3.9900	2.7200	3.7800	2.6100
C7	9.9400	8.1600	10.7700	9.7300
C8	11.5600	11.9800	11.8300	8.9300
C9	6.0600	4.9500	6.1900	5.8900
C10+	48.9900	50.3400	40.8600	47.7300
Benzene	0.3000	0.3800	1.2700	2.7500
Toluene	1.0300	0.1500	3.4900	5.3000
E-Benzene	0.2900	0.2400	0.2200	0.2000
Xylenes	1.7800	1.3700	1.8000	1.3900
n-C6	3.4600	1.9600	3.1400	3.4700
224Trimethylp	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000

Tank ID					API > 40		
E&P Tank Number		**Average**	**ratios to HAP**	**Ratio to VOC**	**Maximum**	**Minimum**	**Average**
Total Emissions (tpy)	Total	785.812			8152.118	129.419	1530.229
VOC Emissions (tpy)	VOC	530.750	**33.837**		5678.554	43.734	1046.343
Methane Emissions (tpy)	Methane	116.167	**7.406**	**0.219**	1206.981	0.197	230.569
HAP Emissions (tpy)	**HAP**	**15.685**		**0.030**	**101.610**	**2.680**	**30.684**
Benzene							
Toluene							
E-Benzene							
Xylenes							
n-C6							
224Trimethylp							
Separator Pressure (psig)	Separator Pressure	126.451			870.000	13.000	231.870
Separator Temperature (F)	Separator Temperature	88.657			140.000	40.000	82.500
Ambient Pressure (psia)							
Ambient Temperature (F)							
C10+ SG		0.893			0.929	0.801	0.873
C10+ MW		292.72			375.000	162.000	241.304
API Gravity	**API Gravity**	**40.6**			**68.0**	**40.0**	**52.8**
Production Rate (bbl/day)							
Reid Vapor Pressure (psia)	RVP	5.691			13.100	3.000	7.983
GOR (scf/bbl)	GOR	88.149			924.960	12.300	172.479
Heating Value of Vapor (Btu/s	Heating value	1968.085					
LP Oil Component		**Composition**					
H2S		0.0679					
O2		0.0000					
CO2		0.3661					
N2		0.0360					
C1		2.9248					
C2		1.6262					
C3		2.7564					
i-C4		1.3958					
n-C4		2.9738					
i-C5		2.4711					
n-C5		2.7194					
C6		3.2723					
C7		8.5230					
C8		10.3202					
C9		5.6686					
C10+		48.1339					
Benzene		0.6044					
Toluene		1.6882					
E-Benzene		0.1797					
Xylenes		1.4353					
n-C6		2.8369					
224Trimethylp		0.0000					
		100.0000					

Tank ID	API <40		
E&P Tank Number	**Maximum**	**Minimum**	**Average**
Total Emissions (tpy)	746.422	13.397	174.327
VOC Emissions (tpy)	598.797	3.087	107.227
Methane Emissions (tpy)	124.465	0.115	22.193
HAP Emissions (tpy)	**19.640**	**0.070**	**3.366**
Benzene	5.674	0.003	0.445
Toluene	6.120	0.003	0.431
E-Benzene	0.086	0.000	0.019
Xylenes	0.732	0.001	0.120
n-C6	16.032	0.052	2.449
224Trimethylp	0.000	0.000	0.000
Separator Pressure (psig)	280.000	4.000	39.857
Separator Temperature (F)			
Ambient Pressure (psia)			
Ambient Temperature (F)			
C10+ SG	0.984	0.861	0.910
C10+ MW	551.000	239.000	334.946
API Gravity	**39.0**	**15.0**	**30.6**
Production Rate (bbl/day)			
Reid Vapor Pressure (psia)	7.400	0.600	3.809
GOR (scf/bbl)	67.220	2.340	18.878
Heating Value of Vapor (Btu/s			
LP Oil Component			
H2S			
O2			
CO2			
N2			
C1			
C2			
C3			
i-C4			
n-C4			
i-C5			
n-C5			
C6			
C7			
C8			
C9			
C10+			
Benzene			
Toluene			
E-Benzene			
Xylenes			
n-C6			
224Trimethylp			

API Gravity >40

VOC Emissions (tpy)	
Mean	1046.343
Standard Error	188.1410357
Median	530.989
Mode	#N/A
Standard Deviation	1276.034588
Sample Variance	1628264.269
Kurtosis	3.35522263
Skewness	1.864492873
Range	5634.82
Minimum	43.734
Maximum	5678.554
Sum	48131.778
Count	46
Largest(1)	5678.554
Confidence Level(95.0%)	378.9354921

	667.4075079
VOC	1046.343
	1425.278492

API Gravity <40

VOC Emissions (tpy)	
Mean	107.2265
Standard Error	15.51304
Median	72.87
Mode	#N/A
Standard Deviation	116.0889
Sample Variance	13476.64
Kurtosis	9.02191
Skewness	2.680349
Range	595.71
Minimum	3.087
Maximum	598.797
Sum	6004.685
Count	56
Largest(1)	598.797
Confidence Level(95.0%)	31.08882

	76.1377
VOC	107.2265
	138.3153

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Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study

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[1] The multispecies analysis of daily air samples collected at the NOAA Boulder Atmospheric Observatory (BAO) in Weld County in northeastern Colorado since 2007 shows highly correlated alkane enhancements caused by a regionally distributed mix of sources in the Denver-Julesburg Basin. To further characterize the emissions of methane and non-methane hydrocarbons (propane, n-butane, i-pentane, n-pentane and benzene) around BAO, a pilot study involving automobile-based surveys was carried out during the summer of 2008. A mix of venting emissions (leaks) of raw natural gas and flashing emissions from condensate storage tanks can explain the alkane ratios we observe in air masses impacted by oil and gas operations in northeastern Colorado. Using the WRAP Phase III inventory of total volatile organic compound (VOC) emissions from oil and gas exploration, production and processing, together with flashing and venting emission speciation profiles provided by State agencies or the oil and gas industry, we derive a range of bottom-up speciated emissions for Weld County in 2008. We use the observed ambient molar ratios and flashing and venting emissions data to calculate top-down scenarios for the amount of natural gas leaked to the atmosphere and the associated methane and non-methane emissions. Our analysis suggests that the emissions of the species we measured are most likely underestimated in current inventories and that the uncertainties attached to these estimates can be as high as a factor of two.

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1. Introduction

[2] Since 2004, the National Oceanic and Atmospheric Administration Earth System Research Laboratory (NOAA ESRL) has increased its measurement network density over North America, with continuous carbon dioxide (CO_2) and carbon monoxide (CO) measurements and daily collection of discrete air samples at a network of tall towers (A. E. Andrews et al., manuscript in preparation, 2012) and bi-weekly discrete air sampling along vertical aircraft profiles (C. Sweeney et al., manuscript in preparation, 2012). Close to 60 chemical species or isotopes are measured in the discrete air samples, including long-lived greenhouse gases (GHGs) such as CO_2, methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6), tropospheric ozone precursors such as CO and several volatile organic compounds (VOCs), and stratospheric-ozone-depleting substances. The NOAA multispecies regional data set provides unique information on how important atmospheric trace gases vary in space and time over the continent, and it can be used to quantify how different processes contribute to GHG burdens and/or affect regional air quality.

[3] In this study we focus our analysis on a very strong alkane atmospheric signature observed downwind of the Denver-Julesburg Fossil Fuel Basin (DJB) in the Colorado Northern Front Range (Figure 1 and auxiliary material

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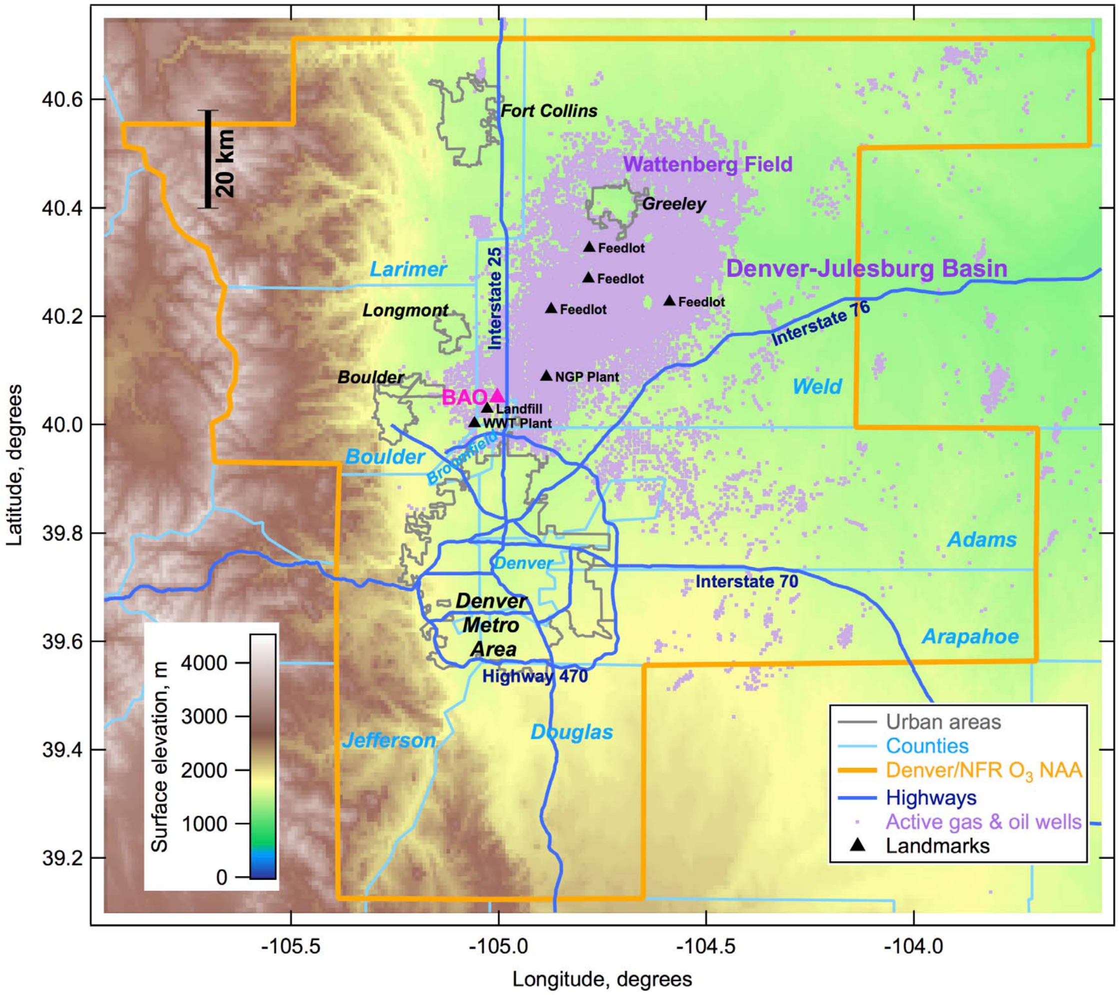

Figure 1. Map of the study area centered on the Boulder Atmospheric Observatory (BAO), located 25 km east-northeast of Boulder. Overlaid on this map are the locations of active oil and gas wells (light purple dots) as of April 2008 (data courtesy of SkyTruth, http://blog.skytruth.org/2008/06/colorado-all-natural-gas-and-oil-wells.html, based on COGCC well data). Also shown are the locations of landmarks used in the study, including selected point sources (NGP Plant = natural gas processing plant, WWT Plant = Lafayette wastewater treatment plant).

Figure S1).[1] In 2008, the DJB was home to over 20,000 active natural gas and condensate wells. Over 90% of the production in 2008 came from tight gas formations.

[4] A few recent studies have looked at the impact of oil and gas operations on air composition at the local and regional scales in North America. *Katzenstein et al.* [2003] reported results of two intensive surface air discrete sampling efforts over the Anadarko Fossil Fuel Basin in the southwestern United States in 2002. Their analysis revealed substantial regional atmospheric CH_4 and non-methane hydrocarbon (NMHC) pollution over parts of Texas, Oklahoma, and Kansas, which they attributed to emissions from the oil and gas industry operations. More recently, *Schnell et al.* [2009] observed very high wintertime ozone levels in the vicinity of the Jonah-Pinedale Anticline natural gas field in western Wyoming. *Ryerson et al.* [2003], *Wert et al.* [2003], *de Gouw et al.* [2009] and *Mellqvist et al.* [2010] reported elevated emissions of alkenes from petrochemical plants and refineries in the Houston area and studied their contribution to ozone formation. *Simpson et al.* [2010] present an extensive analysis of atmospheric mixing ratios for a long list of trace gases over oil sands mining operations in Alberta during one flight of the 2008 Arctic Research of the Composition of the Troposphere from Aircraft and Satellites campaign. Our study distinguishes itself from previous ones by the fact that it relies substantially on the analysis of daily air samples collected at a single tall-tower monitoring site between August 2007 and April 2010.

[5] Colorado has a long history of fossil fuel extraction [*Scamehorn*, 2002]. Colorado natural gas production has been increasing since the 1980s, and its share of national production jumped from 3% in 2000 to 5.4% in 2008. 1.3% of the nationally produced oil in 2008 also came from Colorado, primarily from the DJB in northeastern Colorado and from the Piceance Basin in western Colorado. As of

[1]Auxiliary materials are available in the HTML. doi:10.1029/2011JD016360.

2004, Colorado also contained 43 natural gas processing plants, representing 3.5% of the conterminous U.S. processing capacity [*U.S. Energy Information Administration* (*EIA*), 2006], and two oil refineries, located in Commerce City, in Adams County just north of Denver.

[6] Emissions management requirements for both air quality and climate-relevant gases have led the state of Colorado to build detailed baseline emissions inventories for ozone precursors, including volatile organic compounds (VOCs), and for GHGs. Since 2004, a large fraction of the Colorado Northern Front Range, including Weld County and the Denver metropolitan area, has been in violation of the 8-h ozone national ambient air quality standard [*Colorado Department of Public Health and Environment* (*CDPHE*), 2008]. In December 2007, the Denver and Colorado Northern Front Range (DNFR) region was officially designated as a Federal Non-Attainment Area (NAA) for repeated violation in the summertime of the ozone National Ambient Air Quality Standard (see area encompassed by golden boundary in Figure 1). At the end of 2007, Colorado also adopted a Climate Action Plan, which sets greenhouse gas emissions reduction targets for the state [*Ritter*, 2007].

[7] Methane, a strong greenhouse gas with a global warming potential (GWP) of 25 over a 100 yr time horizon [*Intergovernmental Panel on Climate Change*, 2007], accounts for a significant fraction of Colorado GHG emissions, estimated at 14% in 2005 (*Strait et al.* [2007] and auxiliary material Table S1; note that in this report, the oil and gas industry CH_4 emission estimates were calculated with the EPA State Greenhouse Gas Inventory Tool). The natural gas industry (including exploration, production, processing, transmission and distribution) is the single largest source of CH_4 in the state of Colorado (estimated at 238 Gg/yr or ktonnes/yr), followed closely by coal mining (233 Gg/yr); note that all operating surface and underground coal mines are now in western Colorado. Emission estimates for oil production operations in the state were much lower, at 9.5 Gg/yr, than those from gas production. In 2005, Weld County represented 16.5% of the state's natural gas production and 51% of the state crude oil/ natural gas condensate production (auxiliary material Table S2). Scaling the state's total CH_4 emission estimates from *Strait et al.* [2007], rough estimates for the 2005 CH_4 source from natural gas production and processing operations and from natural gas condensate/oil production in Weld County are 19.6 Gg and 4.8 Gg, respectively. It is important to stress here that there are large uncertainties associated with these inventory-derived estimates.

[8] Other important sources of CH_4 in the state include large open-air cattle feedlots, landfills, wastewater treatment facilities, forest fires, and agriculture waste burning, which are all difficult to quantify. 2005 state total CH_4 emissions from enteric fermentation and manure management were estimated at 143 and 48 Gg/yr, respectively [*Strait et al.*, 2007]; this combined source is of comparable magnitude to the estimate from natural gas systems. On-road transportation is not a substantial source of methane [*Nam et al.*, 2004].

[9] In 2006, forty percent of the DNFR NAA's total anthropogenic VOC emissions were estimated to be due to oil and gas operations [*CDPHE*, 2008]. Over the past few years, the State of Colorado has adopted more stringent VOC emission controls for oil and gas exploration and processing activities. In 2007, the Independent Petroleum Association of Mountain States (IPAMS, now Western Energy Alliance), in conjunction with the Western Regional Air Partnership (WRAP), funded a working group to build a state-of-the-knowledge process-based inventory of total VOC and NOx sources involved in oil and gas exploration, production and gathering activities for the western United State's fossil fuel basins, hereafter referred to as the WRAP Phase III effort (http://www.wrapair.org/forums/ogwg/index.html). Most of the oil and gas production in the DJB is concentrated in Weld County. Large and small condensate storage tanks in the County are estimated to be the largest VOC fossil fuel production source category (59% and 9% respectively), followed by pneumatic devices (valve controllers) and unpermitted fugitives emissions (13% and 9% respectively). A detailed breakdown of the WRAP oil and gas source contributions is shown in auxiliary material Figure S2 for 2006 emissions and projected 2010 emissions [*Bar-Ilan et al.*, 2008a, 2008b]. The EPA NEI 2005 for Weld County, used until recently by most air quality modelers, did not include VOC sources from oil and natural gas operations (auxiliary material Table S3).

[10] Benzene (C_6H_6) is a known human carcinogen and it is one of the 188 hazardous air pollutants (HAPs) tracked by the EPA National Air Toxics Assessment (NATA). Benzene, like VOCs and CH_4, can be released at many different stages of oil and gas production and processing. Natural gas itself can contain varying amounts of aromatic hydrocarbons, including C_6H_6 [*U. S. Environmental Protection Agency* (*EPA*), 1998]. Natural gas associated with oil production (such sources are located in several places around the DJB) usually has higher C_6H_6 levels [*Burns*, 1999] than non-associated natural gas. Glycol dehydrators used at wells and processing facilities to remove water from pumped natural gas can vent large amounts of C_6H_6 to the atmosphere when the glycol undergoes regeneration [*EPA*, 1998]. Condensate tanks, venting and flaring at the wellheads, compressors, processing plants, and engine exhaust are also known sources of C_6H_6 [*EPA*, 1998]. C_6H_6 can also be present in the liquids used for fracturing wells [*EPA*, 2004].

[11] In this paper, we focus on describing and interpreting the measured variability in CH_4 and C_{3-5} alkanes observed in the Colorado Northern Front Range. We use data from daily air samples collected at a NOAA tall tower located in Weld County as well as continuous CH_4 observations and discrete targeted samples from an intensive mobile sampling campaign in the Colorado Northern Front Range. These atmospheric measurements are then used together with other emissions data sets to provide an independent view of methane and non-methane hydrocarbon emissions inventory results.

[12] The paper is organized as follows. Section 2 describes the study design and sampling methods. Section 3 presents results from the tall tower and the Mobile Lab surveys, in particular the strong correlation among the various alkanes measured. Based on the multispecies analysis in the discrete air samples, we were able to identify two major sources of C_6H_6 in Weld County. In section 4.1 we discuss the results and in section 4.2 we compare the observed ambient molar ratios with other relevant data sets, including raw natural gas composition data from 77 gas wells in the DJB. The last discussion section 4.3, is an attempt to shed new light on

Table 1. Locations of a Subset of the NOAA ESRL Towers and Aircraft Profile Sites Used in This Study[a]

Site Code	City	State	Latitude (°N)	Longitude (°E)	Elevation (Meters Above Sea Level)	Sampling Height (Meters Above Ground)
BAO	Erie	Colorado	40.05	105.01	1584	300
LEF	Park Falls	Wisconsin	45.93	90.27	472	396
NWF	Niwot Ridge	Colorado	40.03	105.55	3050	23
STR	San Francisco	California	37.755	122.45	254	232
WGC	Walnut Grove	California	38.26	121.49	0	91
WKT	Moody	Texas	31.32	97.33	251	457
SGP[b]	Southern Great Plains	Oklahoma	36.80	97.50	314	<650

[a]STR and WGC in Northern California are collaborations with Department of Energy Environmental Energy Technologies Division at Lawrence Berkeley National Laboratory (PI: Marc Fischer). The last column gives the altitudes of the quasi-daily flask air samples used in this study. We use midday data for all sites, but at Niwot Ridge Forest we used nighttime data to capture background air from summertime downslope flow. We also show the location information of SGP, a NOAA ESRL aircraft site in north central Oklahoma, for which we used samples taken below 650 m altitude.
[b]Aircraft discrete air samples.

methane and VOC emission estimates from oil and gas operations in Weld County. We first describe how we derived speciated bottom-up emission estimates based on the WRAP Phase III total VOC emission inventories for counties in the DJB. We then used (1) an average ambient propane-to-methane molar ratio, (2) a set of bottom-up estimates of propane and methane flashing emissions in Weld County and (3) three different estimates of the propane-to-methane molar ratio for the raw gas leaks to build top-down methane and propane emission scenarios for venting sources in the county. We also scaled the top-down propane (C_3H_8) estimates with the observed ambient alkane ratios to calculate top-down emission estimates for n-butane (n-C_4H_{10}), i- and n-pentane (i-C_5H_{12}, n-C_5H_{12}), and benzene. We summarize our main conclusions in section 5.

2. The Front Range Emissions Study: Sampling Strategy, Instrumentation, and Sample Analysis

2.1. Overall Experimental Design

[13] The Colorado Northern Front Range study was a pilot project to design and test a new measurement strategy to characterize GHG emissions at the regional level. The anchor of the study was a 300-m tall tower located in Weld County, 25 km east-northeast of Boulder and 35 km north of Denver, called the Boulder Atmospheric Observatory (BAO) [40.05°N, 105.01°W; base of tower at 1584 m above sea level] (Figure 1). The BAO is situated on the southwestern edge of the DJB. A large landfill and a wastewater treatment plant are located a few kilometers southwest of BAO. Interstate 25, a major highway going through Denver, runs in a north-south direction 2 km east of the site. Both continuous and discrete air sampling have been conducted at BAO since 2007.

[14] To put the BAO air samples into a larger regional context and to better understand the sources that impacted the discrete air samples, we made automobile-based on-road air sampling surveys around the Colorado Northern Front Range in June and July 2008 with an instrumented "Mobile Lab" and the same discrete sampling apparatus used at all the NOAA towers and aircraft sampling sites.

2.2. BAO and Other NOAA Cooperative Tall Towers

[15] The BAO tall tower has been used as a research facility of boundary layer dynamics since the 1970s [*Kaimal and Gaynor*, 1983]. The BAO tower was instrumented by the NOAA ESRL Global Monitoring Division (GMD) in Boulder in April 2007, with sampling by a quasi-continuous CO_2 non-dispersive infrared sensor and a CO Gas Filter Correlation instrument, both oscillating between three intake levels (22, 100 and 300 m above ground level) (Andrews et al., manuscript in preparation, 2012). Two continuous ozone UV-absorption instruments have also been deployed to monitor ozone at the surface and at the 300-m level.

[16] The tower is equipped to collect discrete air samples from the 300-m level using a programmable compressor package (PCP) and a programmable flasks package (PFP) described later in section 2.4. Since August 2007 one or two air samples have been taken approximately daily in glass flasks using PFPs and a PCP. The air samples are brought back to GMD for analysis on three different systems to measure a series of compounds, including methane (CH_4, also referred to as C_1), CO, propane (C_3H_8, also referred to as C_3), n-butane (n-C_4H_{10}, nC_4), isopentane (i-C_5H_{12}, iC_5), n-pentane (n-C_5H_{12}, nC_5), acetylene (C_2H_2), benzene, chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs) and hydrofluorocarbons (HFCs). Ethane and i-butane were not measured.

[17] In this study, we use the results from the NOAA GMD multispecies analysis of air samples collected midday at the 300-m level together with 30- second wind speed and direction measured at 300-m. 30-min averages of the wind speed and direction prior to the collection time of each flask are used to separate samples of air masses coming from three different geographic sectors: the North and East (NE sector), where the majority of the DJB oil and gas wells are located; the South (S sector), mostly influenced by the Denver metropolitan area; and the West (W sector), with relatively cleaner air.

[18] In 2008, NOAA and its collaborators were operating a regional air sampling network of eight towers and 18 aircraft profiling sites located across the continental U.S. employing in situ measurements (most towers) and flask sampling protocols (towers and aircraft sites) that were similar to those used at BAO. Median mixing ratios for several alkanes, benzene, acetylene, and carbon monoxide from BAO and a subset of five other NOAA towers and from one aircraft site are presented in the Results (section 3). Table 1 provides the three letter codes used for each sampling site, their locations and sampling heights. STR is located in San Francisco. WGC is located 34 km south of downtown Sacramento in California's Central Valley where

Table 2. List of the Front Range Mobile Lab Measurement and Flasks Sampling Surveys[a]

Road Survey Number	Road Survey Date	Geographical Area/Target Sources	Measurements/Sampling Technique
1	June 4	Boulder	12 flasks
2	June 11	Boulder + Foothills	12 flasks
3	June 19	NOAA-Longmont-Fort Collins- Greeley (Oil and Gas Drilling, Feedlots)	24 flasks
4	July 1	NOAA - Denver	12 flasks
5	July 9	Around Denver	Picarro
6	July 14	NOAA - Greeley	12 flasks
7	July 15	NOAA-Greeley	Picarro
8	July 25	BAO surroundings - Natural Gas Processing Plant - Feedlot	Picarro + 8 flasks
9	July 31	"Regional" CH_4 enhancements, Landfill, Corn field	Picarro + 12 flasks

[a]Some trips (1, 2, 3, 4, 6) sampled air using the flask only. Surveys 5 and 7 used only the continuous analyzers on the Mobile Lab with no discrete flask collection. The last two trips targeted flask sampling close to known point or area sources based on the continuous methane measurement display in the Mobile Lab.

agriculture is the main economic sector. Irrigated crop fields and feedlots contribute to the higher CH_4 observed at WGC. The LEF tower in northern Wisconsin is in the middle of the Chequamegon National Forest which is a mix of temperate/boreal forest and lowlands/wetlands [*Werner et al.*, 2003]. Air samples from NWF (surface elevation 3050 m), in the Colorado Rocky Mountains, mostly reflect relatively unpolluted air from the free troposphere. The 457m tall Texas tower (WKT) is located between Dallas/Fort Worth and Austin. It often samples air masses from the surrounding metropolitan areas. In summer especially, it also detects air masses with cleaner background levels arriving from the Gulf of Mexico. The SGP NOAA aircraft sampling site (Sweeney et al., manuscript in preparation, 2012; http://www.esrl.noaa.gov/gmd/ccgg/aircraft/) in northern Oklahoma is also used in the comparison study. At each aircraft site, twelve discrete air samples are collected at specified altitudes on a weekly or biweekly basis. Oklahoma is the fourth largest state for natural gas production in the USA (EIA, Natural gas navigator, 2008, http://tonto.eia.doe.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm) and one would expect to observe signatures of oil and gas drilling operations at both SGP and BAO. Additional information on the tower and aircraft programs is available at http://www.esrl.noaa.gov/gmd/ccgg/. Median summer mixing ratios for several alkanes, C_2H_2, C_6H_6 and CO are presented in the Results section.

2.3. Mobile Sampling

[19] Two mobile sampling strategies were employed during this study. The first, the Mobile Lab, consisted of a fast response CO_2 and CH_4 analyzer (Picarro, Inc.), a CO gas-filter correlation instrument from Thermo Environmental, Inc., an O_3 UV-absorption analyzer from 2B Technologies and a Global Positioning System (GPS) unit. All were installed onboard a vehicle. A set of 3 parallel inlets attached to a rack on top of the vehicle brought in outside air from a few meters above the ground to the instruments. Another simpler sampling strategy was to drive around and collect flask samples at predetermined locations in the Front Range region. A summary of the on-road surveys is given in Table 2.

[20] The Mobile Lab's Picarro Envirosense $CO_2/CH_4/H_2O$ analyzer (model G1301, unit CFADS09) employs Wavelength-Scanned Cavity Ring-Down Spectroscopy (WS-CRDS), a time-based measurement utilizing a near-infrared laser to measure a spectral signature of the molecule. CO_2, CH_4, and water vapor were measured at a 5-s sampling rate (0.2 Hz), with a standard deviation of 0.09 ppm in CO_2 and 0.7 ppb for CH_4. The sample was not dried prior to analysis, and the CO_2 and CH_4 mole fractions were corrected for water vapor after the experiment based on laboratory tests. For water mole fractions between 1% and 2.5%, the relative magnitude of the CH_4 correction was quasi-linear, with values between 1 and 2.6%. CO_2 and CH_4 mole fractions were assigned against a reference gas tied to the relevant World Meteorological Organization (WMO) calibration scale. Total measurement uncertainties were 0.1 ppm for CO_2 and 2 ppb for CH_4 (Sweeney et al., manuscript in preparation, 2012). The CO and ozone data from the Mobile Lab are not discussed here. GPS data were also collected in the Mobile Lab at 1 Hz, to allow data from the continuous analyzers to be merged with the location of the vehicle.

[21] The excursions with the flask sampler (PFP) focused on characterizing the concentrations of trace gases in Boulder (June 4 and 11, 2008), the northeastern Front Range (June 19), Denver (July 1) and around oil and gas wells and feedlots in Weld County south of Greeley (July 14) (see Table 2). Up to 24 sampling locations away from direct vehicle emissions were chosen before each drive.

[22] Each Mobile Lab drive lasted from four to six hours, after a ~30 min warm-up on the NOAA campus for the continuous analyzer before switching to battery mode. The first two Mobile Lab drives, which did not include discrete air sampling, were surveys around Denver (July 9) and between Boulder and Greeley (July 15). The last two drives with the Mobile Lab (July 25 and 31) combined in situ measurements with discrete flask sampling to target emissions from specific sources: the quasi-real-time display of the data from the continuous CO_2/CH_4 analyzer was used to collect targeted flask samples at strong CH_4 point sources in the vicinity of BAO. Discrete air samples were always collected upwind of the surveying vehicle and when possible away from major road traffic.

2.4. Chemical Analyses of Flask Samples

[23] Discrete air samples were collected at BAO and during the road surveys with a two-component collection apparatus. One (PCP) includes pumps and batteries, along with an onboard microprocessor to control air sampling. Air was drawn through Teflon tubing attached to an expandable 3-m long fishing pole. The second package (PFP) contained a sampling manifold and twelve cylindrical, 0.7 L, glass flasks of flow-through design, fitted with Teflon O-ring on both

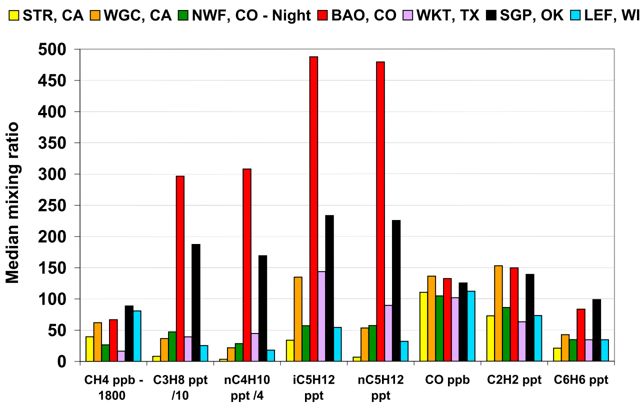

Figure 2. Observed median mixing ratios for several species measured in air samples taken at various sites at midday during June–August (2007–2010). The sites are described in Table 1. Only nighttime samples are shown for NWF to capture background air with predominantly downslope winds. Notice the different units with all columns and the different scaling applied to methane, propane and n-butane.

stopcocks. Before deployment, manifold and flasks were leak-checked then flushed and pressurized to ~1.4 atm with synthetic dry zero-air containing approximately 330 ppm of CO_2 and no detectable CH_4. During sampling, the manifold and flasks were flushed sequentially, at ~5 L min^{-1} for about 1 min and 10 L min^{-1} for about 3 min respectively, before the flasks were pressurized to 2.7 atm. Upon returning to the NOAA lab, the PFP manifold was leak-checked and metadata recorded by the PFP during the flushing and sampling procedures were read to verify the integrity of each air sample collected. In case of detected inadequate flushing or filling, the affected air sample is not analyzed.

[24] Samples collected in flasks were analyzed for close to 60 compounds by NOAA GMD (http://www.esrl.noaa.gov/gmd/ccgg/aircraft/analysis.html). In this paper, we focus on eight species: 5 alkanes (CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12}) as well as CO, C_2H_2 and C_6H_6. CH_4 and CO in each flask were first quantified on one of two nearly identical automated analytical systems (MAGICC 1 and 2). These systems consist of a custom-made gas inlet system, gas-specific analyzers, and system-control software. Our gas inlet systems use a series of stream selection valves to select an air sample or standard gas, pass it through a trap for drying maintained at ~−80°C, and then to an analyzer.

[25] CH_4 was measured by gas chromatography (GC) with flame ionization detection (±1.2 ppb = average repeatability determined as 1 s.d. of ~20 aliquots of natural air measured from a cylinder) [*Dlugokencky et al.*, 1994]. We use the following abbreviations for measured mole fractions: ppm = μmol mol^{-1}, ppb = nmol mol^{-1}, and ppt = pmol mol^{-1}. CO was measured directly by resonance fluorescence at ~150 nm (±0.2 ppb) [*Gerbig et al.*, 1999; *Novelli et al.*, 1998]. All measurements are reported as dry air mole fractions relative to internally consistent calibration scales maintained at NOAA (http://www.esrl.noaa.gov/gmd/ccl/scales.html).

[26] Gas chromatography/mass spectrometric (GC/MS) measurements were also performed on ~200 mL aliquots taken from the flask samples and pre-concentrated with a cryogenic trap at near liquid nitrogen temperatures [*Montzka et al.*, 1993]. Analytes desorbed at ~110°C were then separated by a temperature-programmed GC column (combination 25 m × 0.25 mm DB5 and 30 m × 0.25 mm Gaspro), followed by detection with mass spectrometry by monitoring compound-specific ion mass-to-charge ratios. Flask sample responses were calibrated versus whole air working reference gases which, in turn, are calibrated with respect to gravimetric primary standards (NOAA scales: benzene on NOAA-2006 and all other hydrocarbons (besides CH_4) on NOAA-2008). We used a provisional calibration for n-butane based on a diluted Scott Specialty Gas standard. Total uncertainties for analyses from the GC/MS reported here are <5% (accuracy) for all species except n-C_4H_{10} and C_2H_2, for which the total uncertainty at the time of this study was of the order of 15–20%. Measurement precision as repeatability is generally less than 2% for compounds present at mixing ratios above 10 ppt.

[27] To access the storage stability of the compounds of interest in the PFPs, we conducted storage tests of typically 30 days duration, which is greater than the actual storage time of the samples used in this study. Results for C_2H_2 and C_3H_8 show no statistically significant enhancement or degradation with respect to our "control" (the original test gas tank results) within our analytical uncertainty. For the remaining species, enhancements or losses average less than 3% for the 30 day tests. More information on the quality control of the flask analysis data is available at http://www.esrl.noaa.gov/gmd/ccgg/aircraft/qc.html.

[28] The flask samples were first sent to the GC/MS instrument for hydrocarbons, CFCs, and HFCs before being analyzed for major GHGs. This first step was meant to screen highly polluted samples that could potentially damage the greenhouse gas MAGICC analysis line with concentrations well above "background" levels. The time interval between flask collection and flask analysis spanned between 1 to 11 days for the GC/MS analysis and 3 to 12 days for MAGICC analysis.

3. Results

3.1. BAO Tall Tower: Long-Term Sampling Platform for Regional Emissions

3.1.1. Comparing BAO With Other Sampling Sites in the U.S.

[29] Air samples collected at BAO have a distinct chemical signature (Figure 2), showing enhanced levels of most alkanes (C_3H_8, n-C_4H_{10}, i-C_5H_{12} and n-C_5H_{12}) in comparison to results from other NOAA cooperative tall towers (see summary of site locations in Table 1 and data time series in auxiliary material Figure S1). The midday summer time median mixing ratios for C_3H_8 and n-C_4H_{10} at BAO were at least 6 times higher than those observed at most other tall tower sites. For i-C_5H_{12} and n-C_5H_{12}, the summertime median mixing ratios at BAO were at least 3 times higher than at the other tall towers.

[30] In Figure 2, we show nighttime measurements at the Niwot Ridge Forest tower (NWF) located at a high elevation site on the eastern slopes of the Rocky Mountains, 50 km west of BAO. During the summer nighttime, downslope flow brings clean air to the tower [*Roberts et al.*, 1984]. The median summer mixing ratios at NWF for all the species shown in Figure 2 are much lower than at BAO, as would be expected given the site's remote location.

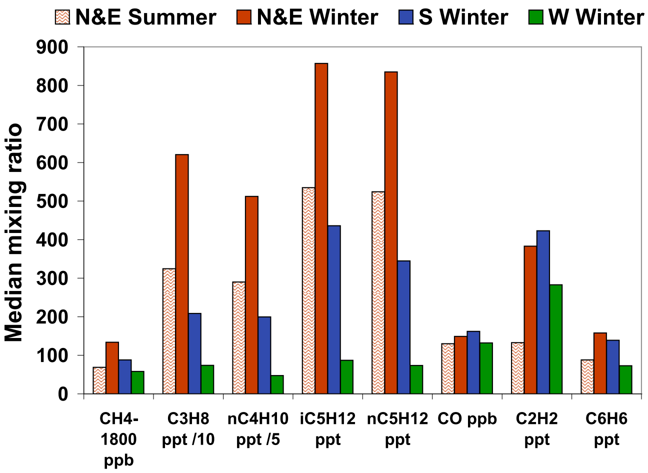

Figure 3. Summertime and wintertime median mixing ratios of several species measured in air samples from the 300-m level at the BAO tower for three wind sectors: North and East (NE) where the density of gas drilling operations is highest, South (S) with Denver 35 km away, and West (W) with mostly clean air. The time span of the data is from August 2007 to April 2010. Summer includes data from June to August and winter includes data from November to April. Due to the small number of data points (<15), we do not show summer values for the S and W wind sectors. Data outside of the 11am-3pm local time window were not used. Notice the different scales used for methane, propane and n-butane. The minimum number of data points used for each wind sector is: NE summer 33, NE winter 89, S winter 65 and W winter 111.

[31] Similarly to BAO, the northern Oklahoma aircraft site, SGP, exhibits high alkane levels in the boundary layer and the highest methane summer median mixing ratio of all sites shown in Figure 2 (1889 ppb at SGP versus 1867 ppb at BAO). As for BAO, SGP is located in an oil- and gas-producing region. Oklahoma, the fourth largest state in terms of natural gas production in the U.S., has a much denser network of interstate and intrastate natural gas pipelines compared to Colorado. *Katzenstein et al.* [2003] documented the spatial extent of alkane plumes around the gas fields of the Anadarko Basin in Texas, Oklahoma, and Kansas during two sampling intensives. The authors estimated that methane emissions from the oil and gas industry in that entire region could be as high as 4–6 Tg CH_4/yr, which is 13–20% of the U.S. total methane emission estimate for year 2005 reported in the latest EPA U.S. GHG Inventory (EPA, Inventory of U.S. Greenhouse Gas emissions and Sinks: 1990–2009, 2011, available at http://www.epa.gov/climatechange/emissions).

[32] Enhancements of CH_4 at BAO are not as striking in comparison to other sites. CH_4 is a long-lived gas destroyed predominantly by its reaction with OH radicals. CH_4 has a background level that varies depending on the location and season [*Dlugokencky et al.*, 1994], making it more difficult to interpret differences in median summer CH_4 mixing ratios at the suite of towers. Since we do not have continuous measurements of CH_4 at any of the towers except WGC, we cannot clearly separate CH_4 enhancements from background variability in samples with levels between 1800 and 1900 ppb if we only look at CH_4 mixing ratios by themselves (see more on this in the next section).

3.1.2. Influence of Different Sources at BAO

3.1.2.1. Median Mixing Ratios in the Three Wind Sectors

[33] To better separate the various sources influencing air sampled at BAO, Figure 3 shows the observed median mixing ratios of several species as a function of prevailing wind direction. For this calculation, we only used samples for which the associated 30-min average wind speed (prior to collection time) was larger than 2.5 m/s. We separated the data into three wind sectors: NE, including winds from the north, northeast and east (wind directions between 345° and 120°); S, including south winds (120° to 240°); and W, including winds from the west (240° to 345°).

[34] For the NE sector, we can further separate summer (June to August) and winter (November to April) data. For the other two wind sectors, only the winter months have enough data points. The species shown in Figure 3 have different photochemical lifetimes [*Parrish et al.*, 1998], and all are shorter-lived in the summer season. This fact, combined with enhanced vertical mixing in the summer, leads to lower mixing ratios in summer than in winter.

[35] Air masses from the NE sector pass over the oil and gas wells in the DJB and exhibit large alkane enhancements. In winter, median mole fractions of C_3-C_5 alkanes are 8 to 11 times higher in air samples from the NE compared to the samples from the W sector, while the median CH_4 value is 76 ppb higher. The NE wind sector also shows the highest median values of C_6H_6, but not CO and C_2H_2.

[36] C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers in air samples from the NE wind sector are much higher than in air samples coming from the Denver metropolitan area in the South wind sector. Besides being influenced by Denver, southern air masses may pass over two operating landfills, the Commerce City oil refineries, and some oil and gas wells (Figure 1). The S sector BAO CO and C_2H_2 mixing ratios are higher than for the other wind sectors, consistent with the higher density of vehicular emission sources [*Harley et al.*, 1992; *Warneke et al.*, 2007; *Baker et al.*, 2008] south of BAO. There are also occasional spikes in CFC-11 and CFC-12 mixing ratios in the S sector (not shown). These are most probably due to leaks from CFC-containing items in the landfills. Air parcels at BAO coming from the east pass over Interstate Highway 25, which could explain some of the high mole fractions observed for vehicle combustion tracers such as CO, C_2H_2, and C_6H_6 in the NE sector data (see more discussion on C_6H_6 and CO in section 4.4 and Figure 4).

[37] The W wind sector has the lowest median mole fractions for all anthropogenic tracers, consistent with a lower density of emission sources west of BAO compared to the other wind sectors. However, the S and W wind sectors do have some data points with high alkane values, and these data will be discussed further below.

3.1.2.2. Strong Alkane Source Signature

[38] To detect if the air sampled at BAO has specific chemical signatures from various sources, we looked at correlation plots for the species shown in Figure 3. Table 3 summarizes the statistics for various tracer correlations for the three different wind sectors. Figure 4 (left) shows correlation plots of some of these BAO species for summer data in the NE wind sector.

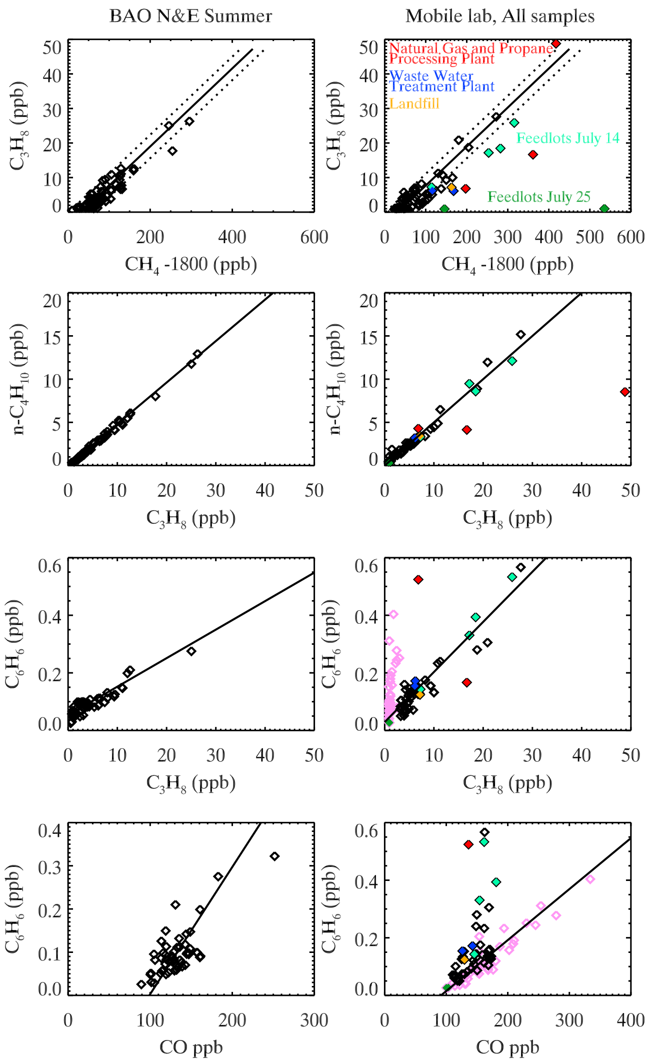

Figure 4. Correlation plots for various species measured in the (left) BAO summertime NE wind sector flask samples and (right) summer 2008 Mobile Lab samples. Data at BAO were filtered to keep only midday air samples collected between June and August over the time period spanning August 2007 to August 2009. See also Table 3.

[39] Even though BAO data from the NE winds show the largest alkane mixing ratios (Figure 3), all three sectors exhibit strong correlations between C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers (Table 3). The r^2 values for the correlations between C_3H_8 and n-C_4H_{10} or the C_5H_{12} isomers are over 0.9 for the NE and W sectors. CH_4 is also well correlated with C_3H_8 in the NE wind sector for both seasons. For the NE wind sector BAO summertime data, a min/max range for the C_3H_8/CH_4 slope is 0.099 to 0.109 ppb/ppb.

[40] The tight correlations between the alkanes suggest a common source located in the vicinity of BAO. Since large alkane enhancements are more frequent in the NE wind sector, this common source probably has larger emissions north and east of the tower. This NE wind sector encompasses Interstate Highway 25 and most of the DJB oil and gas wells. The C_3-C_5 alkane mole fractions do not always correlate well with combustion tracers such as C_2H_2 and CO for the BAO NE wind sector (C_{3-5}/CO and C_{3-5}/C_2H_2: $r^2 < 0.3$ for 50 summer samples; C_{3-5}/CO: $r^2 < 0.4$ and C_{3-5}/C_2H_2: $r^2 \sim 0.6$ for 115 winter samples). These results indicate that the source responsible for the elevated alkanes at BAO is not the major source of CO or C_2H_2, which argues against vehicle combustion exhaust as being responsible. Northeastern Colorado is mostly rural with no big cities. The only operating oil refineries in Colorado are in the northern part of the Denver metropolitan area, south of BAO. The main industrial operations in the northeastern Front Range are oil and natural gas exploration and production and natural gas processing and transmission. We therefore hypothesize here that the oil and gas operations in the DJB, as noted earlier in section 2, are a potentially substantial source of alkanes in the region.

3.1.2.3. At Least Two Sources of Benzene in BAO Vicinity

[41] The median winter C_6H_6 mixing ratio at BAO is higher for the NE wind sector compared to the South wind sector, which comprises the Denver metropolitan area. The C_6H_6-to-CO winter correlation is highest for the S and W wind sectors BAO samples (r^2 = 0.85 and 0.83 respectively) compared to the NE wind sector data (r^2 = 0.69). The C_6H_6-to-CO correlation slope is substantially higher for the NE wind sector data compared to the other two wind sectors, suggesting that there may be a source of benzene in the NE

Table 3. Correlation Slopes and r^2 for Various Species Measured in the BAO Tower Midday Air Flask Samples for Summer (June to August, When More Than 25 Samples Exist) and Winter (November to April) Over the Time Period Spanning August 2007 to April 2010[a]

Sector		BAO North and East														
Season		Summer			Winter			BAO South Winter			BAO West Winter			Mobile Lab Summer		
Molar Ratios y/x	Units	Slope	r^2	n	Slope	r^2	n	Slope	r^2	n	Slope	r^2	n	Slope	r^2	n
C_3H_8/CH_4	ppb/ ppb	**0.104 ± 0.005**	0.85	81	**0.105 ± 0.004**	0.90	115	0.079 ±0.008	0.53	130	**0.085 ± 0.005**	0.73	148	**0.095 ± 0.007**	0.76	77
nC_4H_{10}/C_3H_8	ppb/ ppb	**0.447 ± 0.013**	1.00	81	**0.435 ± 0.005**	1.0	120	**0.449 ± 0.011**	0.98	131	**0.434 ± 0.006**	1.00	151	**0.490 ± 0.011**	1.00	85
iC_5H_{12}/C_3H_8	ppb/ ppb	**0.14 1 ± 0.004**	1.00	81	**0.134 ± 0.004**	0.98	120	**0.142 ± 0.009**	0.81	121	**0.130 ± 0.004**	0.94	151	**0.185 ± 0.011**	0.81	85
nC_5H_{12}/C_3H_8	ppb/ ppb	**0.150 ± 0.003**	1.00	81	**0.136 ± 0.004**	0.98	120	**0.142 ± 0.006**	0.90	131	**0.133 ± 0.003**	0.91	151	**0.186 ± 0.008**	0.92	85
C_6H_6/C_3H_8	ppt/ ppb	10.1 ± 1.2	0.67	49	**8.2 ± 0.5**	0.79	117	-	0.33	130	-	0.39	150	**17.9 ± 1.1**	0.95	46
C_6H_6/ CO	ppt/ ppb	2.89 ± 0.40	0.58	53	3.18 ± 0.24	0.69	112	**1.57 ± 0.08**	0.85	123	**1.81 ± 0.08**	0.83	148	**1.82 ± 0.12**	0.89	39
C_2H_2/ CO	ppt/ ppb	**3.15 ± 0.33**	0.85	81	**7.51 ± 0.39**	0.85	100	**5.03 ± 0.17**	0.92	110	**5.85 ± 0.25**	0.86	131	**4.32 ± 0.28**	0.89	39
C_6H_6/C_2H_2	ppt/ ppt	0.51 ± 0.09	0.55	50	**0.34 ± 0.02**	0.90	103	**0.27 ± 0.02**	0.90	111	**0.32 ± 0.02**	0.96	132	**0.37 ± 0.04**	0.75	39

[a]The three wind sectors used in Figure 3 are also used here with a 30-min average wind speed threshold of 2.5 m/s. Also shown are the slopes derived from flask samples collected by the Mobile Lab in summer 2008. The slope is in bold when r^2 is higher than 0.7 and the slope is not shown when r^2 is less than 0.4. The number of data points (n) used for the slope and r^2 calculations are provided. All slope units are ppb/ppb, except for C_6H_6/C_3H_8, C_6H_6/CO and C_2H_2/CO, which are in ppt/ppb. We used the IDL routine linmix_err.pro for the calculations with the following random measurement errors: 2ppb for CH_4 and CO and 5% for C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12}, C_2H_2, and C_6H_6.

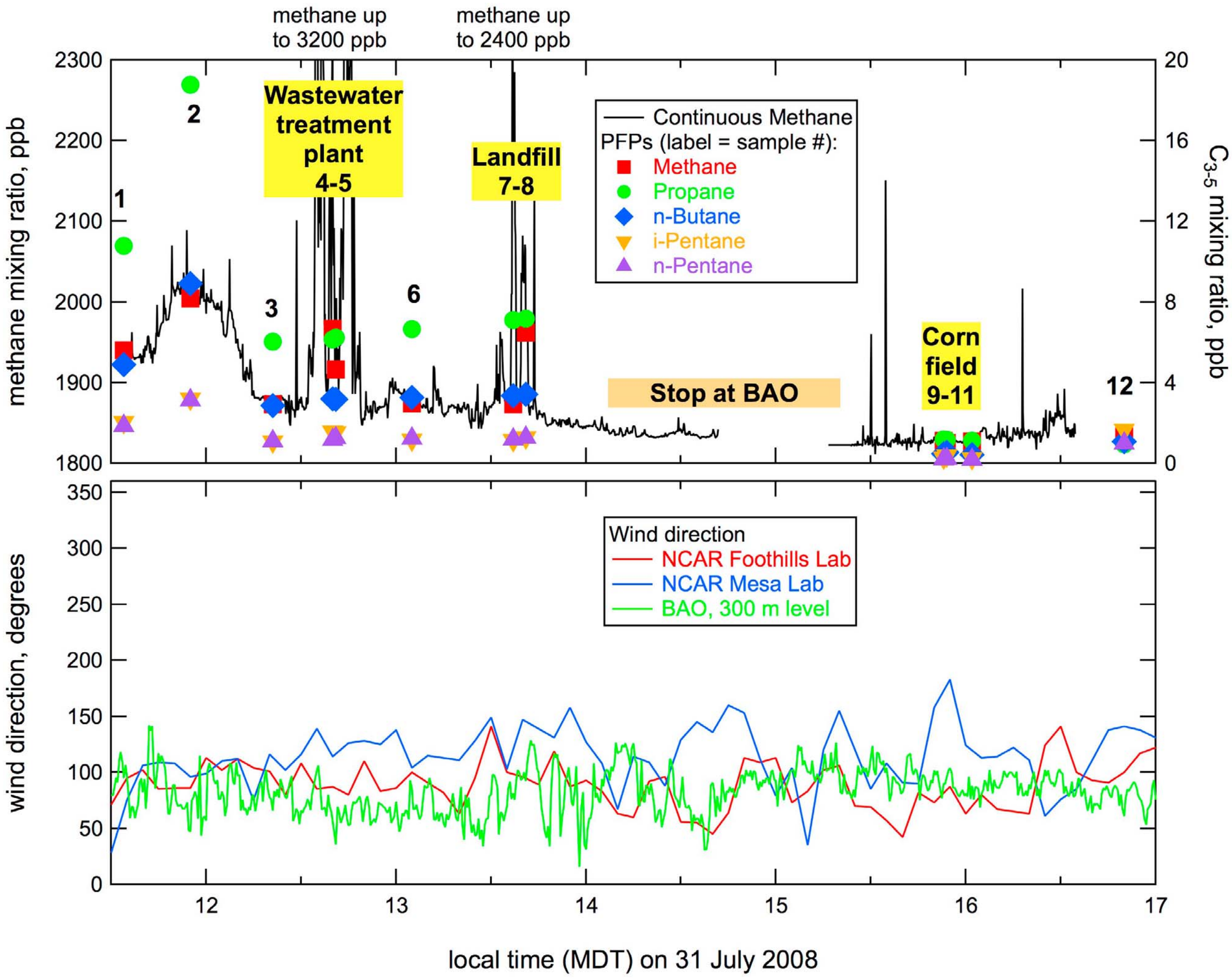

Figure 5. (top) Time series of the continuous methane measurements from Mobile Lab Survey 9 on July 31, 2008. Also shown are the mixing ratio data for the 12 flask samples collected during the road survey. The GC/MS had a faulty high energy dynode cable when these samples were analyzed, resulting in more noisy data for the alkanes and the CFCs ($\sigma < 10\%$ instead of 5%). However, the amplitudes of the $C_{3\text{–}5}$ alkane signals are much larger than the noise here. The methane mixing ratio scale is shown on the left hand vertical axis. For all other alkanes, refer to the right hand vertical axis. (bottom) Time series of wind directions at the NCAR Foothills and Mesa Laboratories in Boulder (see Figure 6 for locations) and from the 300-m level at the BAO on July 31, 2008.

that is not a significant source of CO. The C_6H_6-to-C_2H_2 correlation slope is slightly higher for the NE wind sector data compared to the other two wind sectors. C_6H_6 in the BAO data from the NE wind sector correlates more strongly with C_3H_8 than with CO. The C_6H_6-to-C_3H_8 summer correlation slope for the NE wind sector is 10.1 ± 1.2 ppt/ppb ($r^2 = 0.67$).

[42] For the S and W wind sectors BAO data, the C_6H_6-to-C_2H_2 (0.27 - 0.32 ppt/ppt) and C_6H_6-to-CO (1.57 - 1.81 ppt/ppb) slopes are larger than observed emissions ratios for the Boston/New York City area in 2004: 0.171 ppt/ppt for C_6H_6-to-C_2H_2 ratio and 0.617 ppt/ppb for C_6H_6-to-CO ratio [*Warneke et al.*, 2007]. *Baker et al.* [2008] report an atmospheric molar C_6H_6-to-CO ratio of 0.9 ppt/ppb for Denver in summer 2004, which is in between the Boston/NYC emissions ratio value reported by *Warneke et al.* [2007] and the BAO S and W wind sectors correlation slopes.

[43] The analysis of the BAO C_6H_6 data suggests the existence of at least two distinct C_6H_6 sources in the vicinity of BAO: an urban source related mainly to mobile emissions, and a common source of alkanes and C_6H_6 concentrated in northeastern Colorado. We discuss C_6H_6 correlations and sources in more detail in section 4.4.

3.2. On-Road Surveys: Tracking Point and Area Source Chemical Signatures

[44] Road surveys with flask sampling and the Mobile Lab with the fast-response CH_4 analyzer were carried out in June–July 2008 (Table 2). The extensive chemical analysis of air samples collected in the Front Range provides a snapshot of a broader chemical composition of the regional boundary layer during the time of the study. The Mobile Lab surveys around the Front Range using the in situ CH_4 analyzer allowed us to detect large-scale plumes with long-

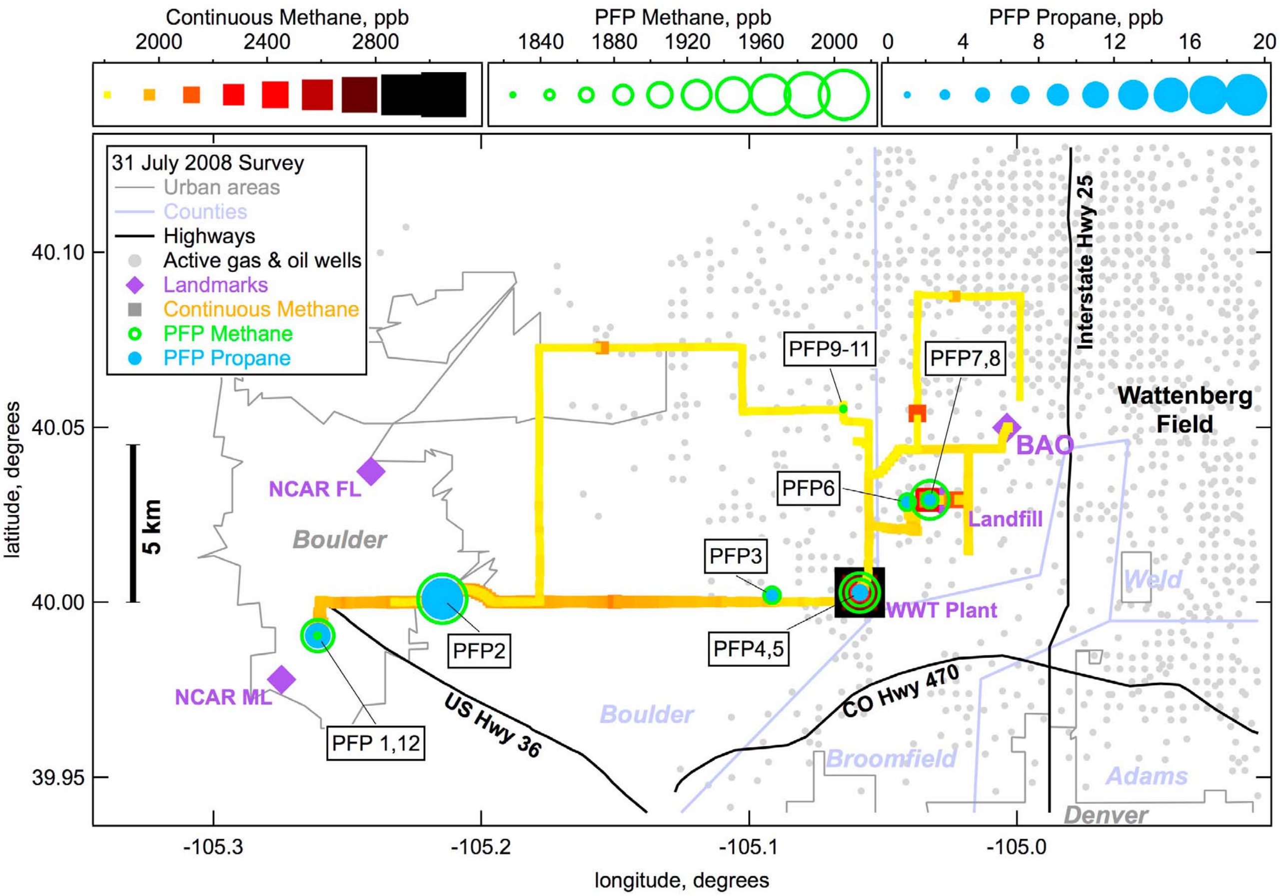

Figure 6. Continuous methane observations (colored squares) and flask (circles) samples collected during the July 31, 2008 Mobile Lab Survey 9 in Boulder and Weld County. The size of the symbols (and the symbol color for the continuous methane data) represents the mixing ratio of continuous/flask methane (squares, green circles) and flask propane (blue circles). The labels indicate the flask sample number (also shown in the time series in Figure 5). NCAR = National Center for Atmospheric Research, FL = NCAR Foothills Laboratory, ML = NCAR Mesa Laboratory, WWT Plant = Lafayette wastewater treatment plant.

lasting enhancements of CH_4 mixing ratios as well as small-scale plumes associated with local CH_4 point sources. In the last two Mobile Lab surveys (surveys 8 and 9), we combined the monitoring of the continuous CH_4 analyzer with targeted flask sampling, using the CH_4 data to decide when to collect flask samples in and out of plumes.

[45] The regional background CH_4 mixing ratio at the surface (interpreted here as the lowest methane level sustained for ~10 min or more) was between 1800 ppb and 1840 ppb for most surveys. Some of the highest "instantaneous" CH_4 mixing ratios measured during the Mobile Lab surveys were: 3166 ppb at a wastewater treatment plant, 2329 ppb at a landfill, 2825 ppb at a feedlot near Dacono, over 7000 ppb close to a feedlot waste pond near Greeley, and 4709 ppb at a large natural gas processing and propane plant in Fort Lupton (Figure 1).

[46] The analysis of the summer 2008 intensive data suggests that regional scale mixing ratio enhancements of CH_4 and other alkanes are not rare events in the Colorado Northern Front Range airshed. Their occurrence and extent depends on both emissions and surface wind conditions, which are quite variable and difficult to predict in this area. During the Mobile Lab road surveys, the high-frequency measurements of CO_2 and CH_4 did not exhibit any correlation. Unlike CO_2, the CH_4 enhancements were not related to on-road emissions. Below we present two examples of regional enhancements of CH_4 observed during the Front Range Mobile Lab surveys.

3.2.1. Survey 9: C_{3-5} Alkane Levels Follow Large-Scale Changes in Methane

[47] Figure 5 shows a time series of the continuous CH_4 mixing ratio data and alkane mixing ratios measured in twelve flask samples collected during the Front Range Mobile Lab survey on 31 July 2008 (flasks 1 to 12, sampled sequentially as shown in Figure 6). The wind direction on that day was from the ENE or E at the NCAR Foothills Lab and BAO tower. The Mobile Lab left the NOAA campus in Boulder around 11:40 A.M. and measured increasing CH_4 levels going east toward the BAO tower (Figure 6). An air sample was collected close to the peak of the CH_4 broad enhancement centered around 11:55 A.M. The CH_4 mixing ratio then decreased over the next 25 min and reached a local minimum close to 1875 ppb. The CH_4 level stayed around 1875 ppb for over one hour and then decreased again, more slowly this time, to ~1830 ppb over the next two hours.

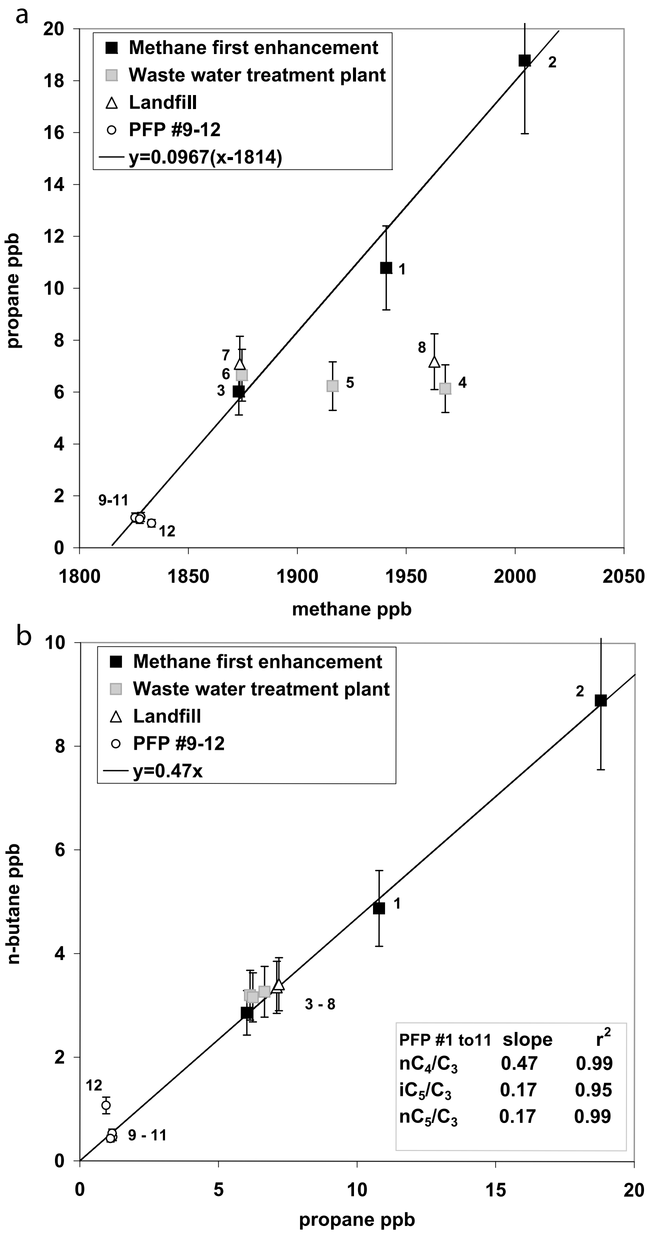

Figure 7. (a) Propane versus methane mixing ratios for air samples collected during Survey 9 on July 31, 2008. (b) The n-butane versus propane mixing ratios in the same air samples. The black line in Figure 7a shows the correlation line for samples not impacted by local sources of methane (all flasks except 4, 5, 8, and 12). The black line in Figure 7b shows the correlation line for all samples except flask 12. The flask sample number is shown next to each data point. The twelve samples were filled sequentially (see Figure 6).

[48] Flasks 1 to 3 were collected before, at the peak, and immediately after the broad CH_4 feature between 11:40 and 12:15. Flasks 4 and 5 were sampled close to a wastewater treatment plant and flasks 7 to 8 were sampled in a landfill. The in situ measurements showed that CH_4 was still elevated above background as these samples were collected. After a 90-min stop at BAO to recharge the Mobile Lab UPS batteries, flasks 9 to 11 were collected in a corn field while the in situ measurements showed lower CH_4 levels. The last flask sample was collected on the NOAA campus just before 17:00 MDT, about 5.5 h after the first flask sample was collected. The flask samples were always collected upwind of the Mobile Lab car exhaust.

[49] Sharp spikes in the continuous CH_4 data reflect local point sources (wastewater treatment plant, landfill). The highly variable signals in both the continuous and discrete CH_4 close to these sources are driven by the spatial heterogeneity of the CH_4 emissions and variations in wind speed and direction. Broader enhancements in the continuous CH_4 data reflect larger (regional) plumes. The last flask (12) sampled at NOAA has much higher levels of combustion tracers (CO, C_2H_2, C_6H_6) than the other samples.

[50] Figure 7 shows correlation plots for C_3H_8 versus CH_4 and n-C_4H_{10} versus C_3H_8 in the 12 flasks taken on 31 July. Air samples not directly influenced by identified point sources (flasks 1–3, 6–7, 9–12) show a very strong correlation between the various measured alkanes. Using the data from the air samples not directly influenced by identified point sources (flasks 1–3, 6–7, 9–12), we derive a C_3H_8-to-CH_4 (C_3/C_1) mixing ratio slope of 0.097 ± 0.005 ppb/ppb (Figure 7a). This slope is very similar to the one observed for the summertime NE wind sector data at BAO (0.104 ± 0.005; Table 3). Three air samples collected downwind of the wastewater treatment plant and the landfill (flasks 4–5 and 8) are off the C_3H_8-to-CH_4 correlation line and have higher CH_4 than air samples collected nearby but not under the influence of these local CH_4 sources (flasks 3 and 6). Flask 8 also has elevated CFC-11 (310 ppt) compared to the other samples collected that day (<255 ppt), probably related to leaks from old appliances buried in the landfill.

[51] The C_3-C_5 alkane mixing ratios in samples collected on 31 July are tightly correlated for flasks 1 to 11 with $r^2 > 0.95$ (Figure 7b). As concluded for the BAO alkane mixing ratio enhancements earlier, this tight correlation suggests that the non-methane alkanes measured during the surveys are coming from the same source types. The nC_4/C_3 correlation slope on 31 July (0.47 ppb/ppb; flasks 1–11) is similar to the summer slope in the BAO NE samples (0.45 ppb/ppb), while the 31 July iC_5/C_3 and nC_5/C_3 slopes are slightly higher (0.17 and 0.17 ppb/ppb, respectively) than for BAO (0.14 and 0.15 ppb/ppb, respectively).

3.2.2. Survey 6: Alkane Enhancements in the Denver-Julesburg Oil and Gas Production Zone and Cattle Feedlot Contributions to Methane

[52] The flask-sampling-only mobile survey on 14 July 2008 focused on the agricultural and oil and gas drilling region south of Greeley. Eleven of the twelve air samples collected on 14 July were taken over the Denver-Julesburg Basin (flasks 2–12 in auxiliary material Figure S3). Figure 8a shows a correlation plot of C_3H_8 versus CH_4 mixing ratios in these air samples. Flasks collected NE of BAO and not near feedlots (flasks 4, 6–8, and 10–12) fall on a line: y = 0.114(x-1830) (r^2 = 0.99). This slope and the correlation slope calculated for the BAO NE wind sector data are indistinguishable (within the 1-σ uncertainties in the slopes). Four samples collected in the vicinity of four different cattle feedlots (flasks 2, 3, 5, and 9) exhibit a lower C_3H_8-to-CH_4 correlation slope (0.083 ppb/ppb, r^2 = 0.93). The r^2 for the C_3H_8-to-CH_4 correlation using all the flasks is 0.91.

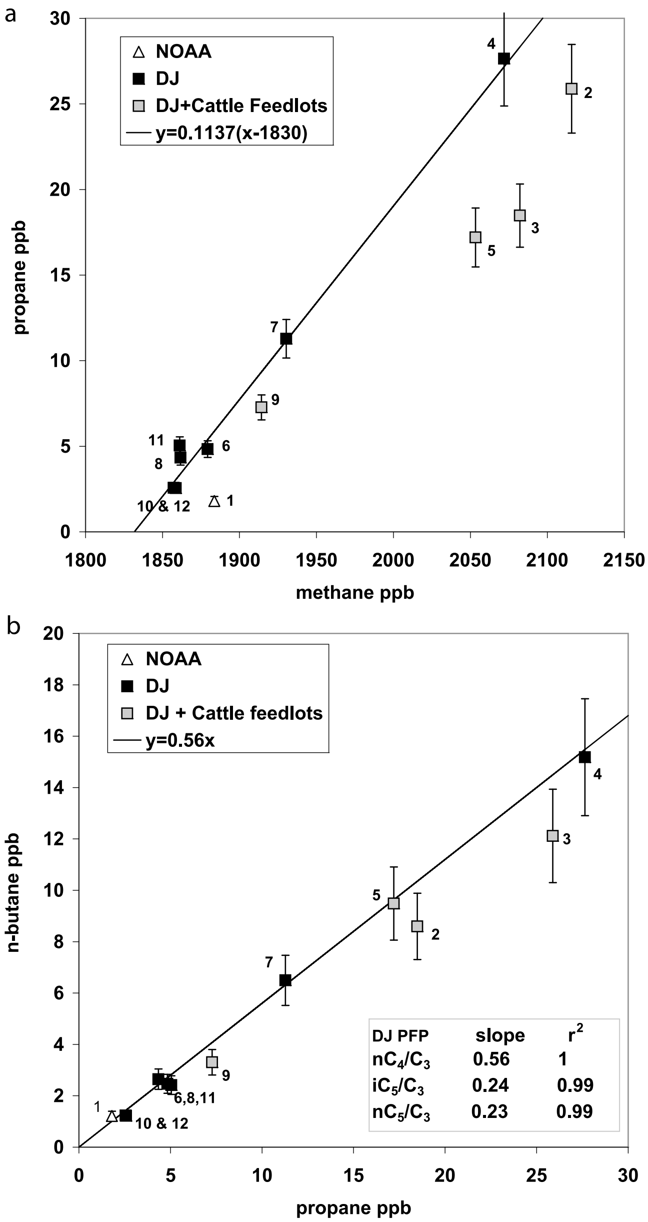

Figure 8. (a) Propane versus methane mixing ratios for air samples collected during Survey 6 on July 14, 2008. (b) The n-butane versus propane mixing ratios in the same air samples. The black line in Figure 8a shows the correlation line for samples not impacted by local sources of methane (all flasks except 1–3, 5, and 9). The black line in Figure 8b shows the correlation line for samples not impacted by local sources of propane.

[53] The n-C_4H_{10} versus C_3H_8 correlation plot and its slope, along with the n-C_4H_{10}–to-C_3H_8 and C_5H_{12}–to-C_3H_8 correlation slopes for air samples not collected downwind of feedlots are shown in Figure 8b. The r^2 for the n-C_4H_{10}-to-C_3H_8 correlation using all the flasks is 0.98, which is slightly higher than the r^2 for the C_3H_8-to-CH_4 correlation using all flasks (0.91). The r^2 for the i-C_5H_{12}-to-n-C_4H_{10} and n-C_5H_{12}-to-n-C_4H_{10} correlations using all the flasks are 0.96 ppb/ppb and 0.99 ppb/ppb, respectively. These results suggest that cattle feedlots have no substantial impact on n-C_4H_{10} and the C_5H_{12} levels.

[54] The strong correlation observed between the various alkane mixing ratios for air samples not collected downwind of feedlots once again suggests that a common source contributes to most of the observed alkanes enhancements. It is possible that some of the C_3H_8 enhancements seen near the feedlots are due to leaks of propane fuel used for farm operations (R. Klusman, personal communication, 2010). Two flask samples were collected downwind of a cattle feedlot near Dacono during Mobile Lab survey 8, on 25 July 2008. The analysis of these samples revealed large CH_4 enhancements (1946 and 2335 ppb), but no enhancement in C_3H_8 ($\sim$1ppb), n-C_4H_{10} (<300ppt), the C_5H_{12} (<130ppt) or C_6H_6 (<30ppt).

[55] For survey 6, the n-C_4H_{10}-to-C_3H_8 correlation slope (0.56 ppb/ppb) is 16% higher than the summer slope observed at BAO for the NE wind sector data, while the 14 July i-C_5H_{12}-to-C_3H_8 and n-C_5H_{12}-to-C_3H_8 correlation slopes (0.24 and 0.23 ppb/ppb, respectively) are 76% and 53% higher, respectively, than the summer NE BAO data. These slopes are higher than for flasks from survey 9. The difference in the C_5/C_3 slopes between the various Mobile Lab surveys data and the BAO NE summer data may reflect the spatial variability in the alkane source molar composition.

3.2.3. Benzene Source Signatures

[56] To look at the C_6H_6 correlations with other tracers, the 88 Mobile Lab flask samples have been divided into two subsets, none of which includes the three samples collected downwind of the natural gas and propane processing plant near Dacono, CO. In the summer, the lifetimes of C_6H_6 and C_3H_8 at 800 mbar and 40°N are close to 3 or 4 days and the lifetime of CO is about 10 days [*Finlayson-Pitts and Pitts*, 2000; *Spivakovsky et al.*, 2000].

[57] The first subset of 39 samples has C_3H_8 mixing ratios smaller than 3 ppb and it includes flasks collected mostly during surveys 2, 3 and 4. For this subset influenced mostly by urban and mobile emissions, C_6H_6 correlates well with CO (slope = 1.82 ppt/ppb, r^2 = 0.89) and C_2H_2 (slope = 0.37 ppt/ppt, r^2 = 0.75) but not with C_3H_8 (r^2 < 0.3). The C_6H_6-to-CO correlation slope for this subset is similar to the correlation slopes for the BAO S and W wind sector winter samples.

[58] The second subset of 46 samples corresponds to flasks with a C_3H_8 mixing ratio larger than 3ppb. These flasks were collected mostly during surveys 1, 6, 8 and 9. For this second subset influenced mostly by emissions from the DJB, C_6H_6 correlates well with C_3H_8 (slope = 17.9 ppt/ppb, r^2 = 0.95) but not with CO or C_2H_2 (r^2 < 0.3). The C_6H_6-to-C_3H_8 slope for these samples is almost twice as big as the slope calculated for the BAO NE wind sector data (10.1 ppt/ppb) (Table 3).

4. Discussion

4.1. Comparing the Alkane Enhancements in the BAO and Mobile Lab Data Sets

[59] In the previous section we showed two examples of enhanced alkanes in northeast Colorado using mobile sampling (surveys 6 and 9 on 14 and 31 July 2008, respectively). With lifetimes against OH removal on the order of 3.5, 1.7 and 1.0 days in the summer at 40°N [*Finlayson-Pitts and Pitts*, 2000; *Spivakovsky et al.*, 2000] respectively, C_3H_8,

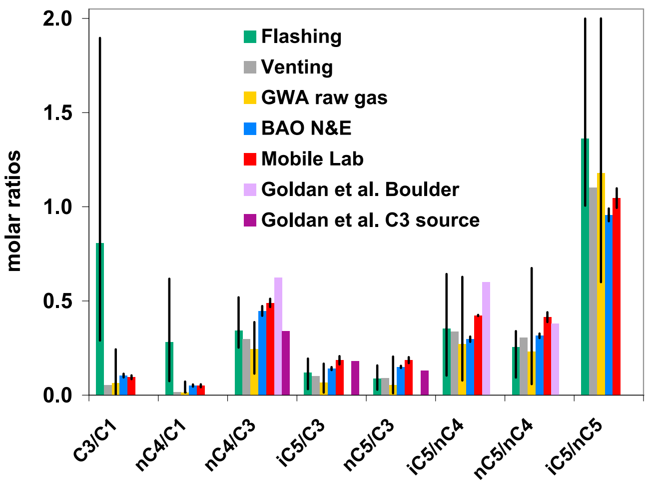

Figure 9. Alkane correlation slopes in air samples collected at BAO (NE wind sector, summer samples only, blue) and over the Denver-Julesburg Basin (red) during the Front Range Study (June–July 2008) are compared with VOC emissions molar ratios for flashing (green) and venting (gray) sources used by *Bar-Ilan et al.* [2008a] for the DJB WRAP Phase III emissions inventory. The error bars indicate the min and max values for the flashing emissions molar ratios. Also shown are the mean, min and max molar ratios derived from the composition analysis of gas samples collected in 2006 at 77 different gas wells in the Great Wattenberg Area (yellow) [*Colorado Oil and Gas Conservation Commission*, 2007]. *Goldan et al.* [1995] data are from a two week measurement campaign in the Foothills, west of Boulder, in February 1991 (light purple). Goldan et al. identified a "local" propane source (lower limit for correlation slope) with clear C_{4-5} alkane ratios to propane (dark purple, see also text). The error bars on the observed atmospheric molar ratios are the 2-sigma calculated for the ratios with linmix_err.pro (http://idlastro.gsfc.nasa.gov/ftp/pro/math/linmix_err.pro).

n-C_4H_{10} and the C_5H_{12} isomers do not accumulate over the continent. Instead their atmospheric mixing ratios and the slopes of correlations between different alkanes reflect mostly local or regional sources within a few days of atmospheric transport.

[60] The source responsible for the alkane enhancements observed at BAO and in multiple surveys during the Front Range Study appears to be located in the northeastern part of the Front Range region within the Denver-Julesburg Basin, so we call it the DJB source. The small differences in alkane correlation slopes for the BAO and Mobile Lab samples likely reflect differences in the emitted alkane molar ratios across this distributed source, as well as the mix of chemical ages for the air samples collected at a variety of locations and on different days.

[61] In Table 3 and Figure 4, we compare the alkane correlation slopes in the Mobile Lab flask data set with the correlation slopes in the BAO data set. To calculate the DJB source C_3H_8-to-CH_4 correlation slope from the Mobile Lab data set, we have removed air samples collected downwind of feedlots, the wastewater treatment plant, and the natural gas and propane processing plant (Figure 1). The Mobile Lab flasks C_3H_8-to-CH_4 correlation slope is 0.095 ± 0.007 ppb/ppb (R^2 = 0.76, 77 samples), similar to the slope calculated for the BAO NE wind sector data. Samples collected downwind of the natural gas processing plant exhibit variable chemical signatures, reflecting a complex mix of contributions from leaks of gas and combustion exhaust from flaring units and compressor engines.

[62] To calculate the DJB source n-C_4H_{10}-to-C_3H_8, i-C_5H_{12}-to-C_3H_8 and n-C_5H_{12}-to-C_3H_8 correlation slopes from the Mobile Lab data set, we have removed the three air samples collected downwind of the natural gas and propane processing plant (Figure 1). The C_4/C_3, i-C_5/C_3 and n-C_5/C_3 correlation slopes in the Mobile Lab data are 0.49, 0.19 and 0.19 ppb/ppb, respectively (r^2 > 0.8, 85 samples). The i-C_5/C_3 and n-C_5/C_3 correlation slopes are 40% and 30% higher, respectively, than the BAO NE sector summer slopes. If we remove the 11 data points from survey 6 samples collected in the middle of the DJB, the C_5H_{12}-to-C_3H_8 ratios are only 15% higher than calculated for the NE sector at BAO.

[63] High correlations among various alkanes were reported in this region by *Goldan et al.* [1995]. In that study, hourly air samples were analyzed with an in situ gas chromatograph deployed on a mesa at the western edge of Boulder for two weeks in February 1991. CH_4 was not measured during that study. The correlation coefficient (r^2) between C_3H_8, n-C_4H_{10}, and the C_5H_{12} isomers was around 0.86, with a clear minimum slope for the abundance ratios [see *Goldan et al.*, 1995, Figure 4]. The authors proposed that the C_4-C_6 alkanes shared one common source with propane (called the "C_3 source" in the next section and in Figure 9), with additional emissions contributing to some C_4-C_6 alkane enhancements.

4.2. Comparing the Front Range Observed Alkane Signatures With VOC Emissions Profiles for Oil And Gas Operations in the Denver-Julesburg Basin

[64] In this section we compare the alkane ratios calculated from the BAO NE wind sector and the Mobile Lab samples to emissions profiles from the DJB oil and gas exploration and production sector. Most of these profiles were provided by the WRAP Phase III inventory team, who developed total VOC and NOx emission inventories for oil and gas production and processing operation in the DJB for 2006 [*Bar-Ilan et al.*, 2008a]. Emissions and activity data were extrapolated by the WRAP Phase III inventory team to derive emission estimates for 2010 based on projected production numbers and on state and federal emissions control regulations put in place in early 2008 for oil and gas permitted activities in the DNFR NAA [*Bar-Ilan et al.*, 2008b]. The VOCs included in the inventories are: C_3H_8, i,n-C_4H_{10}, i,n-C_5H_{12} and higher alkanes, C_6H_6, toluene, ethyl-benzene, xylenes and 224-trimethylpentane. The WRAP Phase III inventories for 2006 and 2010 were only provided as total VOC and NOx emitted at the county level for all the counties in the Colorado part of the DJB. The emission estimates are based on various activity data (including the number of new wells (spuds), the total number of wells, estimates of oil, condensate and gas production, and equipment counts) and measured/reported or estimated VOC speciation profiles for the different source categories. Auxiliary material Figure S2 and *Bar-Ilan et al.* [2008a, 2008b] present more details on how the inventory emission estimates are derived.

[65] We focus primarily on flashing and venting sources here, since the WRAP Phase III inventory indicates that these two sources are responsible for 95% of the total VOC emissions from oil and gas exploration and production operations in Weld County and in the NAA [*Bar-Ilan et al.*, 2008a, 2008b] (see auxiliary material Figure S2). In 2006, all the oil produced in the DJB was from condensate wells. Condensate tanks at well pads or processing plants store a mostly liquid mix of hydrocarbons and aromatics separated from the lighter gases in the raw natural gas. Flash losses or emissions happen for example when the liquid condensate is exposed to decreasing atmospheric pressure: gases dissolved in the liquid are released and some of the heavier compounds may be entrained with these gases. Flashing emissions from condensate storage tanks are the largest source of VOCs from oil and gas operations in the DJB. In the DNFR NAA, operators of large condensate tanks have to control and report emission estimates to the Colorado Department of Public Health and the Environment (CDPHE). In 2006 and 2010 flashing emissions represented 69% and 65% respectively of the total VOC source from oil and gas exploration, production and processing operations, for the nine counties in the NAA (see auxiliary material Figure S2 and *Bar-Ilan et al.* [2008a] for more details on how the estimates are derived).

[66] Venting emissions are related to loss of raw natural gas when a new oil or gas well is drilled or when an existing well is vented (blowdown), repaired or restimulated (recompletion). Equipment at active well sites (e.g., wellhead, glycol dehydrators and pumps) or in the midstream network of compressors and pipelines gathering the raw natural gas can also leak significant amounts of natural gas. In the WRAP Phase III inventory, venting emissions represented 27% and 21% respectively of the total VOC estimated source from the NAA oil and gas operations in 2006 and 2010 (see *Bar-Ilan et al.* [2008a, 2008b] and auxiliary material Figure S2).

[67] The molar compositions of venting and flashing emissions are quite different (see auxiliary material Figure S4). Emissions from flash losses are enriched in C_{2+} alkanes compared to the raw natural gas emissions. To convert the total VOC bottom-up source into speciated emission ratio estimates, we use molar ratio profiles for both flashing and venting emissions reported in three data sets: (1) *Bar-Ilan et al.* [2008a]: mean venting profile used for the 2006 DJB inventory, also called the "Venting-WRAP" profile; (2) *Colorado Oil and Gas Conservation Commission* (*COGCC*) [2007]: composition of 77 samples of raw natural gas collected at different wells in the Greater Wattenberg Area in December 2006, also called "Venting-GWA" profiles. Note that C_6H_6 was not reported in this data set; and (3) Colorado Department of Public Health and the Environment (C. LaPlante, CDPHE, personal communication, 2011): flashing emissions profiles based on condensate composition data from 16 different storage tanks in the DJB and EPA TANK2.0 (flashing emissions model) runs.

[68] Figure 9 shows a comparison of the alkane molar ratios for the raw natural gas and flash emissions data sets with the correlation slopes derived for the Mobile Lab 2008 samples and for air samples collected at BAO in the summer months only (between August 2007 and April 2010) for the NE wind sector (see auxiliary material Table S4 to get the plotted values). The alkane correlation slopes observed at BAO and across the Northern Front Range with the Mobile Lab are all within the range of ratios reported for flashing and/or venting emissions. The C_{3-5} alkane ratios for both flashing and venting emissions are too similar for their atmospheric ratios to be useful in distinguishing between the two source processes. The ambient C_3H_8-to-CH_4 and n-C_4H_{10}-to-CH_4 molar ratios are lower than what could be expected from condensate tank flashing emissions alone, indicating that most of the CH_4 observed came from the venting of raw natural gas. In the next section, we will describe how we derive bottom-up emission estimates for CH_4 and C_3H_8 as well as three top-down emissions scenarios consistent with the observed atmospheric slopes.

[69] Figure 9 also shows the correlation slopes calculated by *Goldan et al.* [1995] for the 1991 Boulder study. These slopes compare very well with the BAO and Mobile Lab results and the oil and gas venting and flashing emissions ratios. *Goldan et al.* [1995] compared the measured C_4/C_3 and C_5/C_3 ratios for the Boulder C_3 source (see definition in section 4.1) with the ratios reported in the locally distributed pipeline-quality natural gas for February 1991, and concluded that the common C_3H_8 and higher alkane source was not linked with the local distribution system of processed natural gas. However, the composition of the raw natural gas at the extraction well is quite different from the purified pipeline-quality natural gas distributed to end-users. Processed pipeline-quality natural gas delivered throughout the USA is almost pure CH_4 [*Gas Research Institute*, 1992]. Since *Goldan et al.* [1995] did not measure CH_4 in their 1991 study, they could not determine if the atmospheric C_{3+}/C_1 alkane ratios were higher than expected in processed natural gas.

4.3. Estimation of the Alkane Source in Weld County

4.3.1. Bottom-Up Speciated Emission Estimates

[70] In this section, we derive bottom-up and top-down estimates of alkane emissions from the DJB source for Weld County. We have averaged the 2006 and 2010 WRAP Phase III total VOC emissions data [*Bar-Ilan et al.*, 2008a, 2008b] to get bottom-up estimates for the year 2008, resulting in 41.3 Gg/yr for flashing emissions and 16.8 Gg/yr for venting emissions. There are no uncertainty estimates provided in the WRAP Phase III inventory. 2006 total VOC flashing emission estimates in Weld County are based on reported emissions for controlled large condensate tanks (34.8 Gg/yr) and calculated emissions for uncontrolled small condensate tanks (5.4 Gg/yr) (see *Bar-Ilan et al.* [2008a] for more details). Uncertainties attached to these estimates may be due to inaccurate emissions factors (number of pounds of VOC flashed per tons of condensate produced) and/or inaccurate estimate of the effectiveness of emission control systems.

[71] The WRAP Phase III total VOC emission from venting sources for Weld County was calculated by averaging industry estimates of the volume of natural gas vented or leaked to the atmosphere by various processes shown in auxiliary material Figure S2 (well blowdown, well completion, pneumatic devices…). A basin-wide average of gas composition analyses provided by oil and gas producers was then used to compute a bottom-up estimate of the total mass of VOC vented to the atmosphere by oil and gas exploration, production and processing operations. Uncertainties attached to the venting source can be related to

Table 4. Bottom-Up (Inventory-Derived) Emission Estimates and Top-Down Emissions Scenarios for CH_4 and C_3H_8 in Weld County

	Bottom-Up Estimates				Top-Down Scenarios: Venting[a] (Gg/yr)			Top-Down Scenarios: TOTAL Bottom-Up Flashing + Top-Down Venting[a] (Gg/yr)			Top-Down Scenarios: Percent Of Production Vented[a,b]		
	Flashing[c] (Gg/yr)	Venting[d] (Gg/yr)	Flashing + Venting (Gg/yr)	Percent of Production Vented[e]	1	2	3	1	2	3	1	2	3
Methane	**11.2**	53.1	64.3	**1.68%**	118.4	92.5	157	**129.6**	103.7	168.2	**4.0%**	3.1%	5.3%
Min[f]	**4**	42	46		86.5	67.6	114.7	90.5	**71.6**	118.7	2.9%	**2.3%**	3.8%
Max[f]	**23**	63	86		172.6	134.9	228.9	195.6	157.9	**251.9**	5.8%	4.5%	**7.7%**
Propane	**18.3**	7.8	26.1		17.4	10.2	28	**35.7**	28.5	46.3			
Min[f]	**14**	1	15		12.7	7.5	20.5	26.7	**21.5**	34.5			
Max[f]	**24**	28	52		25.3	14.9	40.8	49.3	38.9	**64.8**			

[a]The CH_4-to-C_3H_8 molar ratio for vented natural gas is 18.75 (WRAP report estimate) for scenario 1, 15.43 for scenario 2 (median of molar ratios in GWA data set) and 24.83 for scenario 3 (mean of molar ratios in GWA data set).

[b]Using the assumptions of a CH_4 molar ratio of 77% for the vented natural gas and a molar volume for the gas of 23.6 L/mol (Pressure = 14.73 pounds per square inch and Temperature = 60°F) as used by the *EIA* [2004].

[c]The bottom-up flashing emissions for methane and propane were calculated using the 2008 estimate of total VOC flash emissions derived by averaging the WRAP estimate for 2006 and the projection for 2010 (Cf. section 4.3).

[d]The bottom-up venting emissions for methane and propane were calculated using the WRAP Phase III inventory estimate for the total volume of natural gas vented and the GWA 77 natural gas composition profiles.

[e]Using the WRAP Phase III inventory data set and assumptions, including a CH_4 mean molar ratio of 77.44% for the vented natural gas and a molar volume for the gas of 22.4 L/mol.

[f]The minimum and maximum values reported here come from the ensemble of 16 condensate tank emissions speciation profiles provided by CDPHE.

uncertainties in leak rates or intensity of out-gassing events, as well to the variability in the composition of raw natural gas, none of which were quantitatively taken into account in the WRAP Phase III inventory.

[72] Next we describe the calculations, summarized in auxiliary material Figure S5, to derive bottom-up estimates of venting and flashing emissions for the various trace gases we measured using information from the WRAP Phase III inventory and the COGCC GWA raw natural gas composition data set (Table 4 and auxiliary material Figure S6). From the total annual vented VOC source and the average vented emission profile provided by *Bar-Ilan et al.* [2008a] (auxiliary material Table S2), we derived an estimate of the volume of natural gas that we assumed is vented to the atmosphere by the oil and gas production and processing operations in Weld County. Following *Bar-Ilan et al.* [2008a] inventory data and assumptions, we used the weight fraction of total VOC in the vented gas (18.74%), the molar mass of the vented gas (21.5g/mol) and standard pressure and temperature with the ideal gas law to assume that 1 mol of raw natural gas occupies a volume 22.4 L (as was done in the WRAP Phase III inventory). The total volume of vented gas we calculate for Weld County in 2008 is 3.36 billion cubic feet (Bcf), or the equivalent of 1.68% of the total natural gas produced in the county in 2008 (202.1 Bcf). We then use the estimate of the volume of vented gas and the molar composition profiles for the 77 raw natural gas samples reported in the COGCC GWA study to compute average, minimum, and maximum emissions for CH_4, each of the C_{3-5} alkanes we measured, and C_6H_6. Using this procedure, 2008 Weld County average venting CH_4 and C_3H_8 bottom-up source estimates are 53.1 Gg/yr and 7.8 Gg/yr, respectively (Table 4).

[73] For flashing emissions, we distributed the WRAP 2008 total annual VOC source estimate (41.3 Gg/yr) using the modeled flash loss composition profiles for 16 different condensate tanks provided by the CDPHE. Average CH_4 and C_3H_8 emissions as well as the minimum and maximum estimates are reported in Table 4. The 2008 average flashing CH_4 and C_3H_8 bottom-up emission estimates are 11.2 Gg/yr and 18.3 Gg/yr, respectively (Table 4). The total flashing + venting CH_4 and C_3H_8 bottom-up estimates range from 46 to 86 Gg/yr and from 15 to 52 Gg/yr, respectively.

4.3.2. Top-Down Emissions Scenarios

[74] Finally, we use our atmospheric measurements to bring new independent constraints for the estimation of venting and flashing emissions in Weld County in 2008. The exercise consists in calculating three top-down venting emission scenarios for CH_4 and C_3H_8 (x_m, x_p: mass of methane and propane vented respectively) consistent with a mean observed CH_4-to-C_3H_8 atmospheric molar ratio of 10 ppb/ppb (Table 4) in the DJB. We assume, as done earlier in the bottom-up calculations, that the observed C_3H_8-to-CH_4 ratio in the DJB results from a combination of flashing and venting emissions. The bottom-up information used here is (1) the set of speciated flashing emissions derived earlier for the 16 condensate tanks provided by CDPHE for CH_4 and C_3H_8 $(y_m, y_p)_{\mathrm{tank}=1,16}$, and (2) three scenarios for the basin-average raw (vented) natural gas CH_4-to-C_3H_8 molar ratio, denoted $\boldsymbol{v}_{m/p}$. The three values used for basin-average vented gas CH_4-to-C_3H_8 molar ratio are: 18.75, which is the WRAP Phase III inventory assumption (scenario 1); 15.43, which is the median of the molar ratios for the COGCC GWA 77 gas samples (scenario 2); and 24.83, which is the mean of the molar ratios for the COGCC GWA 77 gas samples (scenario 3). For each vented gas profile scenario, we use the set of 16 flash emission estimates to calculate an ensemble of venting emission estimates for CH_4 (x_m) and C_3H_8 (x_p) following the two equations below.

[75] The first equation formalizes the assumption for CH_4-to-C_3H_8 molar ratio of the vented raw natural gas, with M_m (16g/mol) and M_p (44g/mol) being the molar masses of CH_4 and C_3H_8 respectively.:

$$v_{m/p} = \frac{M_p}{M_m} \times \frac{x_m}{x_p} \qquad (1)$$

[76] In the second equation, the mean observed atmospheric CH_4-to-C_3H_8 molar ratio ($a_{m/p}$ = 10 ppb/ppb)

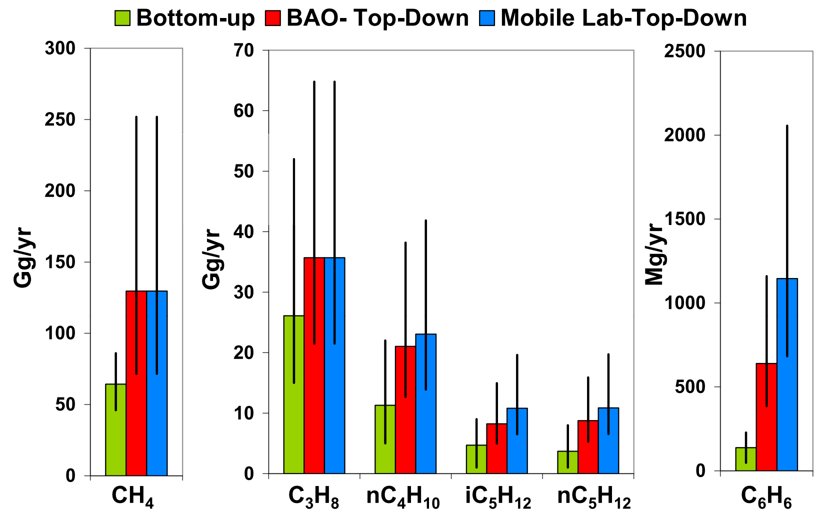

Figure 10. Bottom-up (inventory-derived) emission estimates and top-down emission scenarios for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The vertical bars show scenario 1 average values and the error bars indicate the minimum and maximum values for the three scenarios described in Table 4.

constrains the overall ratio of methane versus propane emitted by both flashing and venting sources. Therefore, for each set of 16 bottom-up flashed emission estimates (y_m, y_p), we have:

$$\frac{M_p(x_m + y_m)}{M_m(x_p + y_p)} = a_{m/p} \tag{2}$$

[77] The analytical solutions to this set of equations are given by:

$$\begin{aligned} x_p &= \frac{1}{(v_{m/p} - a_{m/p})} \times \left(a_{m/p} \times y_p - \frac{M_p}{M_m} y_m \right) \\ x_m &= v_{m/p} \times \frac{M_m}{M_p} \times x_p \end{aligned} \tag{3}$$

[78] The average, minimum and maximum venting emission estimates, x_m and x_p, are reported for the three vented gas profile scenarios in Table 4 and Figure 10.

[79] The first goal of this top-down estimation exercise is to highlight the many assumptions required to build the bottom-up and top-down emission estimates. The choices made for the WRAP Phase III inventory or our top-down calculations are all reasonable, and the uncertainty attached to the values chosen (if available) should be propagated to calculate total uncertainty estimates for the final emission products. When the error propagation is done conservatively, the emission uncertainty is close to a factor of 2 for both CH_4 and C_3H_8. This number is much higher than the 30% uncertainty reported by the EPA for the 2009 national CH_4 source estimate from natural gas systems [*EPA*, 2011].

[80] The scenario 1 mean top-down vented CH_4 source (118.4 Gg/yr) is twice as large as the bottom-up estimate of 53.1 Gg/yr (Table 4). If we assume that 77% (by volume) of the raw gas is CH_4, an average estimate of 118.4 Gg/yr of CH_4 vented would mean that the equivalent of 4% of the 2008 natural gas gross production in Weld County was vented. It is important to note that the top-down scenarios cover a large range (67–229 Gg/yr), corresponding to between 2.3% and 7.7% of the annual production being lost to the atmosphere through venting (Table 4). The lowest estimate is, however, larger than what we derived from the WRAP Phase III bottom-up inventory (1.68%). If instead of using the *EIA* [2004] convention for the molar volume of gas (23.6 L/mol), we used the standard molar volume used by WRAP (22.4 L/mol), our top-down calculations of the volume of gas vented would be 5% lower than reported in Table 4.

[81] Emissions for the other alkanes measured are all derived from the C3H8 total sources scaled with the atmospheric molar ratios observed in the BAO NE summer samples and the Mobile Lab samples. Figure 10 shows a comparison of the bottom-up estimates and the top-down emission scenarios (mean of scenario 1 and overall minimum and maximum of the three scenarios).

[82] The main result of this exercise is that for each of the three top-down total emissions scenarios, the mean estimates for CH_4, n-C_4H_{10} and the C_5H_{12} isomers are at least 60% higher than the bottom-up mean estimates. The minimum top-down emissions scenarios are lower than (in the case of C_3H_8) or higher than (for CH_4, nC_4H_{10}, i-C_5H_{12}, n-C_5H_{12}) the bottom-up mean estimates.

[83] To put the top-down CH_4 source estimate from oil and gas exploration, production and processing operations in perspective, we compare it with an estimate of the passive "geological" CH_4 flux over the entire DJB. *Klusman and Jakel* [1998] reported an average flux of 0.57 mg CH_4/m^2/day in the DJB due to natural microseepage of light alkanes. Multiplied by a rough upper boundary estimate of the DJB surface area (Figure 1), the estimated annual natural flux is 0.66 Gg CH_4 /yr, or less than 1% of the top-down venting source estimated for active exploration and production of natural gas in Weld County.

4.4. Benzene Sources in the Northern Front Range

[84] On-road vehicles are estimated to be the largest source of C_6H_6 in the U.S. (EPA, 2008 report on the environment,

2009, www.epa.gov/roe). Emissions from on-road and off-road vehicles and from large point sources (including chemical plants and refineries) have been regulated by the EPA for over thirty years [*Fortin et al.*, 2005; *Harley et al.*, 2006]. When motor vehicle combustion dominates emissions, such as in the BAO S and W wind sectors, C_6H_6 correlates well with CO and C_2H_2.

[85] Crude oil and natural gas production and processing emitted an estimated 8333 tonnes of benzene nationally in 2005, which represented 2% of the national total C_6H_6 source (EPA, 2008 report on the environment, 2009, www.epa.gov/roe). C_6H_6 and C_3H_8 have similar photochemical lifetimes (~3–4 days in the summer), so the observed atmospheric ratios we report in Table 3 should be close to their emission ratio if they are emitted by a common source. The strong correlation between C_6H_6 and C_3H_8 (Figure 4 and Table 3) for the BAO NE wind sector and in the DJB Mobile Lab air samples suggests that oil and gas operations could also be a non-negligible source of C_6H_6 in the Northern Colorado Front Range.

[86] The C_6H_6-to-C_3H_8 molar ratios in the flash losses from 16 condensate tanks simulated with the EPA TANK model are between 0.4 to 5.6 ppt/ppb. The C_6H_6-to-C_3H_8 molar ratio reported for vented emissions in the WRAP Phase III inventory is 5.3 ppt/ppb, based on regionally averaged raw gas speciation profiles provided by local companies [*Bar-Ilan et al.*, 2008a] (only an average profile was provided, other data is proprietary). These emission ratios are at least a factor of two lower than the atmospheric ratios measured in the Front Range air samples influenced by the DJB source (Table 3).

[87] If we use the mean C_3H_8 emission estimate for scenario 1 described in section 4.3 (35.7 Gg/yr), together with the C_6H_6-to-C_3H_8 correlation slope for the summer BAO NE wind sector data and that from the Mobile Lab samples (10.1 ppt/ppb and 17.9 ppt/ppb respectively), we derive a C_6H_6 emission estimate for the DJB source in Weld County in 2008 of 639 tonnes/yr (min/max range: 478/883 tonnes/yr) and 1145 tonnes/yr (min/max range: 847/1564 tonnes/yr), respectively. As expected, these numbers are much higher than what we derived for the bottom-up flashing and venting emissions (total of 139 tonnes/yr, min/max range of 49–229 tonnes/yr). For comparison, C_6H_6 emissions from facilities in Colorado reporting to the U.S. EPA for the Toxics Release Inventory amounted to a total of 3.9 tonnes in 2008 (EPA, Toxics Release Inventory program, 2009, data available at http://www.epa.gov/triexplorer/chemical.htm) and on–road emissions in Weld County were estimated at 95.4 tonnes/yr in 2008 (C. LaPlante, CDPHE, personal communication, 2011). Based on our analysis, oil and gas operations in the DJB could be the largest source of C_6H_6 in Weld County.

[88] More measurements are needed to further evaluate the various potential sources associated with oil and gas operations (for example, glycol dehydrators and condensate tank flash emissions). The past two iterations of the C_6H_6 emissions inventory developed by the State of Colorado for the National Emissions Inventory and compiled by the EPA do not show much consistency from one year to another. The 2008 and 2005 NEI reported very different C_6H_6 emission estimates for condensate tanks in Weld County (21.5 Mg/yr versus 1120 Mg/yr, respectively; see also auxiliary material Table S3). Estimates in the 2008 NEI are much closer to estimates provided by CDPHE (C. LaPlante, personal communication, 2011) for 2008 (21.3 Mg/yr), suggesting the 2005 NEI estimate may be flawed, even though it is in the range of our top-down estimation. We conclude that the current level of understanding of emissions of C_6H_6 from oil and gas operations cannot explain the top-down range of estimates we derive in our study, suggesting that, once again, more field measurements are needed to understand and quantify oil and gas operation sources.

5. Conclusion

[89] This study provides a regional overview of the processes impacting ambient alkane and benzene levels in northeastern Colorado in the late 2000s. We report atmospheric observations collected by two sampling platforms: a 300-m tall tower located in the SW corner of Weld County (samples from 2007 to 2010), and road surveys by a Mobile Lab equipped with a continuous methane analyzer and discrete canister sampling (June–July 2008). The analysis of the tower data filtered by wind sector reveals a strong alkane and benzene signature in air masses coming from northeastern Colorado, where the main activity producing these compounds is related to oil and gas operations over the Denver–Julesburg Fossil Fuel Basin. Using the Mobile Lab platform, we sampled air directly downwind of different methane sources (oil and gas wells, a landfill, feedlots, and a wastewater treatment plant) and collected targeted air samples in and out of plumes. The tall tower and Mobile Lab data both revealed a common source for air masses with enhanced alkanes. In the data from both platforms, the alkane mixing ratios were strongly correlated, with slight variations in the correlation slopes depending on the location and day of sampling. The alkanes did not correlate with combustion tracers such as carbon monoxide and acetylene. We hypothesize that the observed alkanes were emitted by the same source located over the Denver-Julesburg Basin, "the DJB source."

[90] The second part of the study brings in information on VOC emissions from oil and gas activities in the DJB from the detailed bottom-up WRAP Phase III inventory [*Bar Ilan et al.*, 2008a, 2008b]. We have used the total VOC emission inventory and associated emissions data for DJB condensate and gas production and processing operations to calculate annual emission estimates for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The main findings are summarized below:

1. The emissions profiles for flashing and venting losses are in good agreement with the atmospheric alkane enhancement ratios observed during this study and by *Goldan et al.* [1995] in Boulder in 1991. This is consistent with the hypothesis that the observed alkane atmospheric signature is due to oil and gas operations in the DJB.

2. The three top-down emission scenarios for oil and gas operations in Weld County in 2008 give a rather large range of potential emissions for CH_4 (71.6–251.9 Gg/yr) and the higher alkanes. Except for propane, the lowest top-down alkanes emission estimates are always larger than the inventory-based mean estimate we derived based on the WRAP Phase III inventory data and the COGCC GWA raw gas composition data set.

3. There are notable inconsistencies between our results and state and national regulatory inventories. In 2008 gas wells in Weld County represented 15% of the state's production. Based on our top-down analysis, Weld County methane emissions from oil and gas production and processing represent at least 30% of the state total methane source from natural gas systems derived by *Strait et al.* [2007] using the EPA State Inventory Tool. The methane source from natural gas systems in Colorado is most likely underestimated by at least a factor of two. Oil and gas operations are the largest source of alkanes in Weld County. They were included as a source of "total VOC" in the 2008 EPA NEI for Weld County but not in the 2005 NEI.

4. There are at least two main sources of C_6H_6 in the region: one related to combustion processes, which also emit CO and C_2H_2 (engines and mobile vehicles), and one related to the DJB alkane source. The C_6H_6 source we derived based on flashing and venting VOC emissions in the WRAP inventory (143 Mg/yr) most likely underestimates the actual total source of C_6H_6 from oil and gas operations. Our top-down source estimates for C_6H_6 from oil and gas operations in Weld County cover a large range: 385–2056 Mg/yr. Again, the lowest figure is much higher than reported in the 2008 CDPHE inventory for Weld County oil and gas total point sources (61.8 Mg/yr).

5. Samples collected at the BAO tall tower or while driving around the Front Range reflect the emissions from a complex mix of sources distributed over a large area. Using a multispecies analysis including both climate and air quality relevant gases, we can start unraveling the contributions of different source types. Daily multispecies measurements from the NOAA collaborative network of tall towers in the U.S. provide a unique opportunity to understand source chemical signatures in different airsheds and how these emissions may change over time.

6. More targeted multispecies well-calibrated atmospheric measurements are needed to evaluate current and future bottom-up inventory emissions calculations for the fossil fuel energy sector and to reduce uncertainties on absolute flux estimates for climate and air quality relevant trace gases.

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Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources

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Abstract

Background: Technological advances (e.g. directional drilling, hydraulic fracturing), have led to increases in unconventional natural gas development (NGD), raising questions about health impacts.

Objectives: We estimated health risks for exposures to air emissions from a NGD project in Garfield County, Colorado with the objective of supporting risk prevention recommendations in a health impact assessment (HIA).

Methods: We used EPA guidance to estimate chronic and subchronic non-cancer hazard indices and cancer risks from exposure to hydrocarbons for two populations: (1) residents living > ½ mile from wells and (2) residents living ≤ ½ mile from wells.

Results: Residents living ≤ ½ mile from wells are at greater risk for health effects from NGD than are residents living > ½ mile from wells. Subchronic exposures to air pollutants during well completion activities present the greatest potential for health effects. The subchronic non-cancer hazard index (HI) of 5 for residents ≤ ½ mile from wells was driven primarily by exposure to trimethylbenzenes, xylenes, and aliphatic hydrocarbons. Chronic HIs were 1 and 0.4. for residents ≤ ½ mile from wells and > ½ mile from wells, respectively. Cumulative cancer risks were 10 in a million and 6 in a million for residents living ≤ ½ mile and > ½ mile from wells, respectively, with benzene as the major contributor to the risk.

Conclusions: Risk assessment can be used in HIAs to direct health risk prevention strategies. Risk management approaches should focus on reducing exposures to emissions during well completions. These preliminary results indicate that health effects resulting from air emissions during unconventional NGD warrant further study. Prospective studies should focus on health effects associated with air pollution.

Key Words: natural gas development; risk assessment; air pollution; hydrocarbon emissions

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The authors declare they have no competing financial interests.

Abbreviations[1]

1.0 Introduction

The United States (US) holds large reserves of unconventional natural gas resources in coalbeds, shale, and tight sands. Technological advances, such as directional drilling and hydraulic fracturing, have led to a rapid increase in the development of these resources. For example, shale gas production had an average annual growth rate of 48 percent over the 2006 to 2010 period and is projected to grow almost fourfold from 2009 to 2035 (US EIA 2011). The number of unconventional natural gas wells in the US rose from 18,485 in 2004 to 25,145 in 2007 and is expected to continue increasing through at least 2020 (Vidas and Hugman 2008). With this expansion, it is becoming increasingly common for unconventional natural gas development (NGD) to occur near where people live, work, and play. People living near these development sites are raising public health concerns, as rapid NGD exposes more people to various potential stressors (COGCC 2009a).

The process of unconventional NGD is typically divided into two phases: well development and production (EPA 2010a, US DOE 2009). Well development involves pad preparation, well drilling, and well completion. The well completion process has three primary stages: 1) completion transitions (concrete well plugs are installed in wells to separate fracturing stages and then drilled out to release gas for production); 2) hydraulic fracturing ("fracking": the high pressure injection of water, chemicals, and propants into the drilled well to release the

[1] BTEX, benzene, toluene, ethylbenzene, and xylenes; COGCC, Colorardo Oil and Gas Conservation Commission; HAP, hazardous air pollutant; HI, hazard index; HIA, health impact assessment; HQ, hazard quotient; NATA, National Air Toxics Assessment; NGD, natural gas development

natural gas); and 3) flowback, the return of fracking and geologic fluids, liquid hydrocarbons ("condensate") and natural gas to the surface (EPA 2010a, US DOE 2009). Once development is complete, the "salable" gas is collected, processed, and distributed. While methane is the primary constituent of natural gas, it contains many other chemicals, including alkanes, benzene, and other aromatic hydrocarbons (TERC 2009).

As shown by ambient air studies in Colorado, Texas, and Wyoming, the NGD process results in direct and fugitive air emissions of a complex mixture of pollutants from the natural gas resource itself as well as diesel engines, tanks containing produced water, and on site materials used in production, such as drilling muds and fracking fluids (CDPHE 2009; Frazier 2009; Walther 2011; Zielinska et al. 2011). The specific contribution of each of these potential NGD sources has yet to be ascertained and pollutants such as petroleum hydrocarbons are likely to be emitted from several of these NGD sources. This complex mixture of chemicals and resultant secondary air pollutants, such as ozone, can be transported to nearby residences and population centers (Walther 2011, GCPH 2010).

Multiple studies on inhalation exposure to petroleum hydrocarbons in occupational settings as well as residences near refineries, oil spills and petrol stations indicate an increased risk of eye irritation and headaches, asthma symptoms, acute childhood leukemia, acute myelogenous leukemia, and multiple myeloma (Glass et al. 2003; Kirkeleit et al. 2008; Brosselin et al. 2009; Kim et al. 2009; White et al. 2009). Many of the petroleum hydrocarbons observed in these studies are present in and around NGD sites (TERC 2009). Some, such as benzene, ethylbenzene, toluene, and xylene (BTEX) have robust exposure and toxicity knowledge bases, while toxicity information for others, such as heptane, octane, and diethylbenzene, is more limited. Assessments in Colorado have concluded that ambient benzene levels demonstrate an increased potential risk of developing cancer as well as chronic and acute non-cancer health effects in areas of Garfield County Colorado where NGD is the only major industry other than agriculture (CDPHE 2007; Coons and Walker 2008;CDPHE 2010). Health effects associated with benzene include acute and chronic nonlymphocytic leukemia, acute myeloid leukemia, chronic lymphocytic leukemia, anemia, and other blood disorders and immunological effects. (ATSDR 2007, IRIS 2010). In addition, maternal exposure to ambient levels of benzene recently has been associated with an increase in birth prevalence of neural tube defects (Lupo 2010). Health effects of xylene exposure include eye, nose, and throat irritation, difficulty in breathing, impaired lung function, and nervous system impairment (ATSDR 2007b). In addition, inhalation of xylenes, benzene, and alkanes can adversely affect the nervous system (Carpenter et al. 1978; Nilsen et al. 1988; Galvin et al. 1999; ATSDR 2007a; ATSDR 2007b).

Previous assessments are limited in that they were not able to distinguish between risks from ambient air pollution and specific NGD stages, such as well completions or risks between residents living near wells and residents living further from wells. We were able to isolate risks to residents living near wells during the flowback stage of well completions by using air quality data collected at the perimeter of the wells while flowback was occurring.

Battlement Mesa (population ~ 5,000) located in rural Garfield County, Colorado is one community experiencing the rapid expansion of NGD in an unconventional tight sand resource. A NGD operator has proposed developing 200 gas wells on 9 well pads located as close as 500 feet from residences. Colorado Oil and Gas Commission (COGCC) rules allow natural gas wells to be placed as close as 150 feet from residences (COGCC 2009b). Because of community concerns, as described elsewhere, we conducted a health impact assessment (HIA) to assess how the project may impact public health (Witter et al. 2011), working with a range of stakeholders to identify the potential public health risks and benefits.

In this article, we illustrate how a risk assessment was used to support elements of the HIA process and inform risk prevention recommendations by estimating chronic and subchronic non-cancer hazard indices (HIs) and lifetime excess cancer risks due to NGD air emissions.

2.0 Methods

We used standard United States Environmental Protection Agency (EPA) methodology to estimate non-cancer HIs and excess lifetime cancer risks for exposures to hydrocarbons (US EPA 1989, US EPA 2004) using residential exposure scenarios developed for the NGD project. We used air toxics data collected in Garfield County from January 2008 to November 2010 as part of a special study of short term exposures as well as on-going ambient air monitoring program data to estimate subchronic and chronic exposures and health risks (Frazier 2009, GCPH 2009, GCPH 2010, GCPH 2011, Antero 2010).

2.1 Sample collection and analysis:

All samples were collected and analyzed according to published EPA methods. Analyses were conducted by EPA certified laboratories. The Garfield County Department of Public Health (GCPH) and Olsson Associates, Inc. (Olsson) collected ambient air samples into evacuated SUMMA® passivated stainless-steel canisters over 24-hour intervals. The GCPH collected the samples from a fixed monitoring station and along the perimeters of four well pads and shipped samples to Eastern Research Group for analysis of 78 hydrocarbons using EPA's compendium method TO-12, Method for the Determination of Non-Methane Organic Compounds in Ambient Air Using Cyrogenic Preconcentration and Direct Flame Ionization Detection (US EPA 1999). Olsson collected samples along the perimeter of one well pad and shipped samples to Atmospheric Analysis and Consulting, Inc. for analysis of 56 hydrocarbons (a subset of the 78 hydrocarbons determined by Eastern Research Group) using method TO-12. Per method TO-12, a fixed volume of sample was cryogenically concentrated and then desorbed onto a gas chromatography column equipped with a flame ionization detector. Chemicals were identified by retention time and reported in a concentration of parts per billion carbon (ppbC). The ppbC values were converted to micrograms per cubic meter ($\mu g/m^3$) at 01.325 kilo Pascals and 298.15 Kelvin.

Two different sets of samples were collected from rural (population < 50,000) areas in western Garfield County over varying time periods. The main economy, aside from the NGD industry, of western Garfield County is agricultural. There is no other major industry.

2.1.1 NGD Area Samples

The GCPH collected ambient air samples every six days between January 2008 and November 2010 (163 samples) from a fixed monitoring station located in the midst of rural home sites and ranches and NGD, during both the well development and production. The site is located on top of a small hill and 4 miles upwind of other potential emission sources, such as a major highway (Interstate-70) and the town of Silt, CO (GCPH 2009, GCPH 2010, GCPH 2011).

2.1.2 Well Completion Samples

The GCPH collected 16 ambient air samples at each cardinal direction along 4well pad perimeters (130 to 500 feet from the well pad center) in rural Garfield County during well completion activities. The samples were collected on the perimeter of 4 well pads being developed by 4 different natural gas operators in summer 2008 (Frazier 2009). The GCPH worked closely with the NGD operators to ensure these air samples were collected during the period while at least one well was on uncontrolled (emissions not controlled) flowback into collection tanks vented directly to the air. The number of wells on each pad and other activities occurring on the pad were not documented. Samples were collected over 24 to 27-hour intervals, and samples included emissions from both uncontrolled flowback and diesel engines (i.e., from. trucks and generators supporting completion activities). In addition, the GCPH collected a background sample 0.33 to 1 mile from each well pad (Frazier 2009). The highest hydrocarbon levels corresponded to samples collected directly downwind of the tanks (Frazier 2009, Antero 2010). The lowest hydrocarbon levels corresponded either to background samples or samples collected upwind of the flowback tanks (Frazier 2009, Antero 2010).

Antero Resources Inc., a natural gas operator, contracted Olsson to collect eight 24-hour integrated ambient air samples at each cardinal direction at 350 and 500 feet from the well pad center during well completion activities conducted on one of their well pads in summer 2010 (Antero 2010). Of the 12 wells on this pad, 8 were producing salable natural gas; 1 had been drilled but not completed; 2 were being hydraulically fractured during daytime hours, with ensuing uncontrolled flowback during nighttime hours; and 1 was on uncontrolled flowback during nighttime hours.

All five well pads are located in areas with active gas production, approximately one mile from Interstate-70.

2.2 Data assessment

We evaluated outliers and compared distributions of chemical concentrations from NGD area and well completion samples using Q-Q plots and the Mann-Whitney U test, respectively, in EPA's ProUCL version 4.00.05 software (US EPA 2010b). The Mann-Whitney U test was used because the measurement data were not normally distributed. Distributions were considered as significantly different at an alpha of 0.05. Per EPA guidance, we assigned the exposure concentration as either the 95 percent upper confidence limit (UCL) of the mean concentration for compounds found in 10 or more samples or the maximum detected concentration for compounds found in more than 1 but fewer than 10 samples. This latter category included three compounds: 1,3-butadiene, 2,2,4-trimethylpentane, and styrene in the well completion samples. EPA's ProUCL software was used to select appropriate methods based on sample distributions and detection frequency for computing 95 percent UCLs of the mean concentration (US EPA 2010b).

2.3 Exposure assessment

Risks were estimated for two populations: (1) residents > ½ mile from wells; and (2) residents ≤½ mile from wells. We defined residents ≤ ½ mile from wells as living near wells, based on residents reporting odor complaints attributed to gas wells in the summer of 2010 (COGCC 2011).

Exposure scenarios were developed for chronic non-cancer HIs and cancer risks. For both populations, we assumed a 30-year project duration based on an estimated 5-year well development period for all well pads, followed by 20 to 30 years of production. We assumed a resident lives, works, and otherwise remains within the town 24 hours/day, 350 days/year and that lifetime of a resident is 70 years, based on standard EPA reasonable maximum exposure (RME) defaults (US EPA 1989).

2.3.1 Residents > ½ mile from well pads

As illustrated in Figure 1, data from the NGD area samples were used to estimate chronic and subchronic risks for residents > ½ mile from well development and production throughout the project. The exposure concentrations for this population were the 95 percent UCL on the mean concentration and median concentration from the 163 NGD samples.

2.3.2 Residents ≤ ½ mile from well pads

To evaluate subchronic non-cancer HIs from well completion emissions, we estimated that a resident lives ≤ ½ mile from two well pads resulting a 20- month exposure duration based on 2 weeks per well for completion and 20 wells per pad, assuming some overlap between activities. The subchronic exposure concentrations for this population were the 95 percent UCL on the mean concentration and the median concentration from the 24 well completion samples. To evaluate chronic risks to residents ≤ ½ mile from wells throughout the NGD project, we calculated a time-weighted exposure concentration (C_{S+c}) to account for exposure to emissions from well completions for 20-months followed by 340 months of exposure to emissions from the NGD area using the following formula:

$$C_{S+c} = (C_c \times ED_c/ED) + (C_S \times ED_S/ED)$$

where:

C_c = Chronic exposure point concentration (μg/m^3) based on the 95 percent UCL of the mean concentration or median concentration from the 163 NGD area samples

ED_c = Chronic exposure duration

C_S = Subchronic exposure point concentration (μg/m^3) based on the 95 percent UCL of the mean concentration or median concentration from the 24 well completion samples

ED_S = Subchronic exposure duration

ED = Total exposure duration

2.4 Toxicity assessment and risk characterization

For non-carcinogens, we expressed inhalation toxicity measurements as a reference concentration (RfC in units of μg/m^3 air). We used chronic RfCs to evaluate long-term exposures of 30 years and subchronic RfCs to evaluate subchronic exposures of 20-months. If a subchronic

RfC was not available, we used the chronic RfC. We obtained RfCs from (in order of preference) EPA's Integrated Risk Information System (IRIS) (U. S. EPA 2011), California Environmental Protection Agency (CalEPA) (CalEPA 2003), EPA's Provisional Peer-Reviewed Toxicity Values (ORNL 2009), and Health Effects Assessment Summary Tables (U.S. EPA 1997). We used surrogate RfCs according to EPA guidance for C_5 to C_{18} aliphatic and C_6 to C_{18} aromatic hydrocarbons which did not have a chemical-specific toxicity value (U.S. EPA 2009a). We derived semi-quantitative hazards, in terms of the hazard quotient (HQ), defined as the ratio between an estimated exposure concentration and RfC. We summed HQs for individual compounds to estimate the total cumulative HI. We then separated HQs specific to neurological, respiratory, hematological, and developmental effects and calculated a cumulative HI for each of these specific effects.

For carcinogens, we expressed inhalation toxicity measurements as inhalation unit risk (IUR) in units of risk per $\mu g/m^3$. We used IURs from EPA's IRIS (US EPA 2011) when available or the CalEPA (CalEPA 2003). The lifetime cancer risk for each compound was derived by multiplying estimated exposure concentration by the IUR. We summed cancer risks for individual compounds to estimate the cumulative cancer risk. Risks are expressed as excess cancers per 1 million population based on exposure over 30 years.

Toxicity values (i.e., RfCs or IURs) or a surrogate toxicity value were available for 45 out of 78 hydrocarbons measured. We performed a quantitative risk assessment for these hydrocarbons. The remaining 33 hydrocarbons were considered qualitatively in the risk assessment.

3.0 Results

3.1 Data assessment

Evaluation of potential outliers revealed no sampling, analytical, or other anomalies were associated with the outliers. In addition, removal of potential outliers from the NGD area samples did not change the final HIs and cancer risks. Potential outliers in the well completion samples were associated with samples collected downwind from flowback tanks and are representative of emissions during flowback. Therefore, no data was removed from either data set.

Descriptive statistics for concentrations of the hydrocarbons used in the quantitative risk assessment are presented in Table 1. A list of the hydrocarbons detected in the samples that were considered qualitatively in the risk assessment because toxicity values were not available is presented in Table 2. Descriptive statistics for all hydrocarbons are available in Supplemental Table 1. Two thirds more hydrocarbons were detected at a frequency of 100 percent in the well completion samples (38 hydrocarbons) than in the NGD area samples (23 hydrocarbons). Generally, the highest alkane and aromatic hydrocarbon median concentrations were observed in the well completion samples, while the highest median concentrations of several alkenes were observed in the NGD area samples. Median concentrations of benzene, ethylbenzene, toluene, and m-xylene/p-xlyene were 2.7, 4.5, 4.3, and 9 times higher in the well completion samples than in the NGD area samples, respectively. Wilcoxon-Mann-Whitney test results indicate that concentrations of hydrocarbons from well completion samples were significantly higher than concentrations from NGD area samples ($p<0.05$) with the exception of 1,2,3-trimethylbenzene, n-pentane, 1,3-butadiene, isopropylbenzene, n-propylbenzene, propylene, and styrene (Supplemental Table 2).

3.2 Non-cancer hazard indices

Table 3 presents chronic and subchronic RfCs used in calculating non-cancer HIs, as well critical effects and other effects. Chronic non-cancer HQ and HI estimates based on ambient air concentrations are presented in Table 4. The total chronic HIs based on the 95% UCL of the mean concentration were 0.4 for residents > ½ mile from wells and 1 for residents ≤ ½ mile from wells. Most of the chronic non-cancer hazard is attributed to neurological effects with neurological HIs of 0.3 for residents > ½ mile from wells and 0.9 for residents ≤ ½ mile from wells.

Total subchronic non-cancer HQs and HI estimates are presented in Table 5. The total subchronic HIs based on the 95% UCL of the mean concentration were 0.2 for residents > ½ mile from wells and 5 for residents ≤ ½ mile from wells. The subchronic non-cancer hazard for residents > ½ mile from wells is attributed mostly to respiratory effects (HI = 0.2), while the subchronic hazard for residents ≤ ½ mile from wells is attributed to neurological (HI = 4), respiratory (HI = 2), hematologic (HI = 3), and developmental (HI =1) effects.

For residents > ½ mile from wells, aliphatic hydrocarbons (51 percent), trimethylbenzenes (22 percent), and benzene (14 percent) are primary contributors to the chronic non-cancer HI. For residents ≤ ½ mile from wells, trimethylbenzenes (45 percent), aliphatic hydrocarbons (32 percent), and xylenes (17 percent) are primary contributors to the chronic non-cancer HI, and trimethylbenzenes (46 percent), aliphatic hydrocarbons (21 percent) and xylenes (15 percent) also are primary contributors to the subchronic HI.

3.3 Cancer Risks

Cancer risk estimates calculated based on measured ambient air concentrations are presented in Table 6. The cumulative cancer risks based on the 95% UCL of the mean concentration were 6 in a million for residents > ½ from wells and 10 in a million for residents ≤

½ mile from wells. Benzene (84 percent) and 1,3-butadiene (9 percent) were the primary contributors to cumulative cancer risk for residents > ½ mile from wells. Benzene (67 percent) and ethylbenzene (27 percent) were the primary contributors to cumulative cancer risk for residents ≤ ½ mile from wells.

4.0 Discussion

Our results show that the non-cancer HI from air emissions due to natural gas development is greater for residents living closer to wells. Our greatest HI corresponds to the relatively short-term (i.e., subchronic), but high emission, well completion period. This HI is driven principally by exposure to trimethylbenzenes, aliphatic hydrocarbons, and xylenes, all of which have neurological and/or respiratory effects. We also calculated higher cancer risks for residents living nearer to wells as compared to residents residing further from wells. Benzene is the major contributor to lifetime excess cancer risk for both scenarios. It also is notable that these increased risk metrics are seen in an air shed that has elevated ambient levels of several measured air toxics, such as benzene (CDPHE 2009, GCPH 2010).

4.1 Representation of Exposures from NGD

It is likely that NGD is the major source of the hydrocarbons observed in the NGD area samples used in this risk assessment. The NGD area monitoring site is located in the midst of multi-acre rural home sites and ranches. Natural gas is the only industry in the area other than agriculture. Furthermore, the site is at least 4 miles upwind from any other major emission source, including Interstate 70 and the town of Silt, Colorado. Interestingly, levels of benzene, m,p-xylene, and 1,3,5-trimethylbenzene measured at this rural monitoring site in 2009 were higher than levels measured at 27 out of 37 EPA air toxics monitoring sites where SNMOCs were measured, including urban sites such as Elizabeth, NJ, Dearborn, MI, and Tulsa, OK

(GCPH 2010, US EPA 2009b). In addition, the 2007 Garfield County emission inventory attributes the bulk of benzene, xylene, toluene, and ethylbenzene emissions in the county to NGD, with NGD point and non-point sources contributing five times more benzene than any other emission source, including on-road vehicles, wildfires, and wood burning. The emission inventory also indicates that NGD sources (e.g. condensate tanks, drill rigs, venting during completions, fugitive emissions from wells and pipes, and compressor engines) contributed ten times more VOC emissions than any source, other than biogenic sources (e.g plants, animals, marshes, and the earth) (CDPHE 2009）.

Emissions from flowback operations, which may include emissions from various sources on the pads such as wells and diesel engines, are likely the major source of the hydrocarbons observed in the well completion samples. These samples were collected very near (130 to 500 feet from the center) well pads during uncontrolled flowback into tanks venting directly to the air. As for the NGD area samples, no sources other than those associated with NGD were in the vicinity of the sampling locations.

Subchronic health effects, such as headaches and throat and eye irritation reported by residents during well completion activities occurring in Garfield County, are consistent with known health effects of many of the hydrocarbons evaluated in this analysis (COGCC 2011; Witter et al. 2011). Inhalation of trimethylbenzenes and xylenes can irritate the respiratory system and mucous membranes with effects ranging from eye, nose, and throat irritation to difficulty in breathing and impaired lung function (ATSDR 2007a; ATSDR 2007b; US EPA 1994). Inhalation of trimethylbenzenes, xylenes, benzene, and alkanes can adversely affect the nervous system with effects ranging from dizziness, headaches, fatigue at lower exposures to numbness in the limbs, incoordination, tremors, temporary limb paralysis, and unconsciousness at higher exposures (Carpenter et al. 1978; Nilsen et al. 1988; US EPA 1994; Galvin et al. 1999; ATSDR 2007a; ATSDR 2007b).

4.2 Risk Assessment as a Tool for Health Impact Assessment

HIA is a policy tool used internationally that is being increasingly used in the United States to assess multiple complex hazards and exposures in communities. Comparison of risks between residents based on proximity to wells illustrates how the risk assessment process can be used to support the HIA process. An important component of the HIA process is to identify where and when public health is most likely to be impacted and to recommend mitigations to reduce or eliminate the potential impact (Collins and Koplan 2009). This risk assessment indicates that public health most likely would be impacted by well completion activities, particularly for residents living nearest the wells. Based on this information, suggested risk prevention strategies in the HIA are directed at minimizing exposures for those living closet to the well pads, especially during well completion activities when emissions are the highest. The HIA includes recommendations to (1) control and monitor emissions during completion transitions and flowback; (2) capture and reduce emissions through use of low or no emission flowback tanks; and (3) establish and maintain communications regarding well pad activities with the community (Witter et al 2011).

4.3 Comparisons to Other Risk Estimates

This risk assessment is one of the first studies in the peer-reviewed literature to provide a scientific perspective to the potential health risks associated with development of unconventional natural gas resources. Our results for chronic non-cancer HIs and cancer risks for residents > than ½ mile from wells are similar to those reported for NGD areas in the relatively few previous risk assessments in the non-peer reviewed literature that have addressed this issue

(CDPHE 2010, Coons and Walker 2008, CDPHE 2007, Walther 2011). Our risk assessment differs from these previous risk assessments in that it is the first to separately examine residential populations nearer versus further from wells and to report health impact of emissions resulting from well completions. It also adds information on exposure to air emissions from development of these resources. These data show that it is important to include air pollution in the national dialogue on unconventional NGD that, to date, has largely focused on water exposures to hydraulic fracturing chemicals.

4.4 Limitations

As with all risk assessments, scientific limitations may lead to an over- or underestimation of the actual risks. Factors that may lead to overestimation of risk include use of: 1) 95 percent UCL on the mean exposure concentrations; 2) maximum detected values for 1,3-butadiene, 2,2,4-trimethylpentane, and styrene because of a low number of detectable measurements; 3) default RME exposure assumptions, such as an exposure time of 24 hours per day and exposure frequency of 350 days per year; and 4) upper bound cancer risk and non-cancer toxicity values for some of our major risk drivers. The benzene IUR, for example, is based on the high end of a range of maximum likelihood values and includes uncertainty factors to account for limitations in the epidemiological studies for the dose-response and exposure data (US EPA 2011a). Similiarly, the xylene chronic RfC is adjusted by a factor of 300 to account for uncertainties in extrapolating from animal studies, variability of sensitivity in humans, and extrapolating from subchronic studies (US EPA 2011a). Our use of chronic RfCs values when subchronic RfCs were not available may also have overestimated 1,3-butadiene, n-propylbenzene, and propylene subchronic HQs. None of these three chemicals, however, were primary contributors to the subchronic HI, so their overall effect on the HI is relatively small.

Several factors may have lead to an underestimation of risk in our study results. We were not able to completely characterize exposures because several criteria or hazardous air pollutants directly associated with the NGD process via emissions from wells or equipment used to develop wells, including formaldehyde, acetaldehyde, crotonaldehyde, naphthalene, particulate matter, and polycyclic aromatic hydrocarbons, were not measured. No toxicity values appropriate for quantitative risk assessment were available for assessing the risk to several alkenes and low molecular weight alkanes (particularly < C_5 aliphatic hydrocarbons). While at low concentrations the toxicity of alkanes and alkenes is generally considered to be minimal (Sandmeyer, 1981), the maximum concentrations of several low molecular weight alkanes measured in the well completion samples exceeded the 200 - 1000μg/m^3 range of the RfCs for the three alkanes with toxicity values: n-hexane, n-pentane, and n-nonane (US EPA 2011a, ORNL 2009). We did not consider health effects from acute (i.e., less than one hour) exposures to peak hydrocarbon emissions because there were not appropriate measurements. Previous risk assessments have estimated an acute HQ of 6 from benzene in grab samples collected when residents noticed odors they attributed to NGD (CDPHE 2007). We did not include ozone or other potentially relevant exposure pathways such as ingestion of water and inhalation of dust in this risk assessment because of a lack of available data. Elevated concentrations of ozone precursors (specifically, VOCs and nitrogen oxides) have been observed in Garfield County's NGD area and the 8-hr average ozone concentration has periodically approached the 75 ppb National Ambient Air Quality Standard (NAAQS) (CDPHE 2009, GCPH 2010).

This risk assessment also was limited by the spatial and temporal scope of available monitoring data. For the estimated chronic exposure, we used 3 years of monitoring data to estimate exposures over a 30 year exposure period and a relatively small database of 24 samples collected at varying distances up to 500 feet from a well head (which also were used to estimate shorter-term non-cancer hazard index). Our estimated 20-month subchronic exposure was limited to samples collected in the summer, which may have not have captured temporal variation in well completion emissions. Our ½ mile cut point for defining the two different exposed populations in our exposure scenarios was based on complaint reports from residents living within ½ mile of existing NGD, which were the only data available. The actual distance at which residents may experience greater exposures from air emissions may be less than or greater than a ½ mile, depending on dispersion and local topography and meteorology. This lack of spatially and temporally appropriate data increases the uncertainty associated with the results.

Lastly, this risk assessment was limited in that appropriate data were not available for apportionment to specific sources within NGD (e.g diesel emissions, the natural gas resource itself, emissions from tanks, etc.). This increases the uncertainty in the potential effectiveness of risk mitigation options.

These limitations and uncertainties in our risk assessment highlight the preliminary nature of our results. However, there is more certainty in the comparison of the risks between the populations and in the comparison of subchronic to chronic exposures because the limitations and uncertainties similarly affected the risk estimates.

4.5 Next Steps

Further studies are warranted, in order to reduce the uncertainties in the health effects of exposures to NGD air emissions, to better direct efforts to prevent exposures, and thus address the limitations of this risk assessment. Next steps should include the modeling of short- and longer-term exposures as well as collection of area, residential, and personal exposure data, particularly for peak short-term emissions. Furthermore, studies should examine the toxicity of hydrocarbons, such as alkanes, including health effects of mixtures of HAPs and other air pollutants associated with NGD. Emissions from specific emission sources should be characterized and include development of dispersion profiles of HAPs. This emissions data, when coupled with information on local meteorological conditions and topography, can help provide guidance on minimum distances needed to protect occupant health in nearby homes, schools, and businesses. Studies that incorporate all relevant pathways and exposure scenarios, including occupational exposures, are needed to better understand the impacts of NGD of unconventional resources, such as tight sands and shale, on public health. Prospective medical monitoring and surveillance for potential air pollution-related health effects is needed for populations living in areas near the development of unconventional natural gas resources.

5.0 Conclusions

Risk assessment can be used as a tool in HIAs to identify where and when public health is most likely to be impacted and to inform risk prevention strategies directed towards efficient reduction of negative health impacts. These preliminary results indicate that health effects resulting from air emissions during development of unconventional natural gas resources are most likely to occur in residents living nearest to the well pads and warrant further study. Risk prevention efforts should be directed towards reducing air emission exposures for persons living and working near wells during well completions.

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Figure 1: Relationship between completion samples and natural gas development area samples and residents living ≤ ½ mile and > ½ mile from wells.

[a]Time weighted average based on 20-month contribution from well completion samples and 340- month contribution from natural gas development samples.

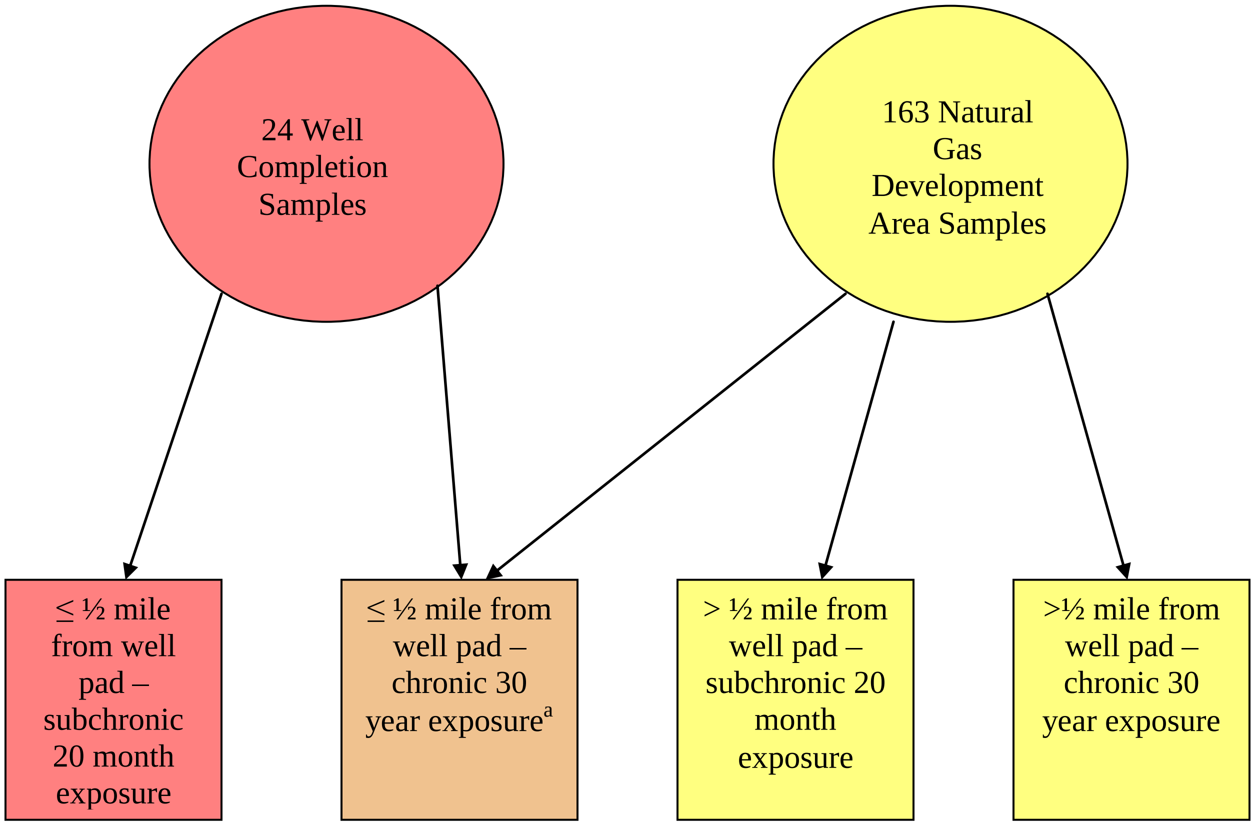
24 Well Completion Samples
163 Natural Gas Development Area Samples
≤ ½ mile from well pad – subchronic 20 month exposure
≤ ½ mile from well pad – chronic 30 year exposure[a]
> ½ mile from well pad – subchronic 20 month exposure
>½ mile from well pad – chronic 30 year exposure

Table 1: Descriptive statistics for hydrocarbon concentrations with toxicity values in 24-hour integrated samples collected in NGD area and samples collected during well completions

	NGD Area Sample Results[a]							Well Completion Sample Results[b]						
Hydrocarbon (µg/m^3)	No.	% > MDL	Med	SD	95% UCL[c]	Min	Max	No.	% > MDL	Med	SD	95% UCL[c]	Min	Max
1,2,3-Trimethylbenzene	163	39	0.11	0.095	0.099	0.022	0.85	24	83	0.84	2.3	3.2	0.055	12
1,2,4-Trimethylbenzene	163	96	0.18	0.34	0.31	0.063	3.1	24	100	1.7	17	21	0.44	83
1,3,5-Trimethylbenzene	163	83	0.12	0.13	0.175	0.024	1.2	24	100	1.3	16	19.5	0.33	78
1,3-Butadiene	163	7	0.11	0.020	0.0465	0.025	0.15	16	56	0.11	0.021	NC	0.068	0.17
Benzene	163	100	0.95	1.3	1.7	0.096	14	24	100	2.6	14	20	0.94	69
Cyclohexane	163	100	2.1	8.3	6.2	0.11	105	24	100	5.3	43	58	2.21	200
Ethylbenzene	163	95	0.17	0.73	0.415	0.056	8.1	24	100	0.77	47	54	0.25	230
Isopropylbenzene	163	38	0.15	0.053	0.074	0.020	0.33	24	67	0.33	1.0	1.0	0.0	4.8
Methylcyclohexane	163	100	3.7	4.0	6.3	0.15	24	24	100	14	149	190	3.1	720
m-Xylene/p-Xylene	163	100	0.87	1.2	1.3	0.16	9.9	24	100	7.8	194	240	2.0	880
n-Hexane	163	100	4.0	4.2	6.7	0.13	25	24	100	7.7	57	80	1.7	255
n-Nonane	163	99	0.44	0.49	0.66	0.064	3.1	24	100	3.6	61	76	1.2	300
n-Pentane	163	100	9.1	9.8	14	0.23	62	24	100	11	156	210	3.9	550
n-Propylbenzene	163	66	0.10	0.068	0.10	0.032	0.71	24	88	0.64	2.4	3.3	0.098	12
o-Xylene	163	97	0.22	0.33	0.33	0.064	3.6	24	100	1.2	40	48.5	0.38	190
Propylene	163	100	0.34	0.23	0.40	0.11	2.5	24	100	0.41	0.34	0.60	0.16	1.9
Styrene	163	15	0.15	0.26	0.13	0.017	3.4	24	21	0.13	1.2	NC	0.23	5.9
Toluene	163	100	1.8	6.2	4.8	0.11	79	24	100	7.8	67	92	2.7	320
Aliphatic hydrocarbons $C_5 – C_8$[d]	163	NC	29	NA	44	1.7	220	24	NC	56	NA	780	24	2700
Aliphatic hydrocarbons $C_9 – C_{18}$[e]	163	NC	1.3	NA	14	0.18	400	24	NC	7.9	NA	100	1.4	390
Aromatic hydrocarbons $C_9 – C_{18}$[f]	163	NC	0.57	NA	0.695	0.17	5.6	24	NC	3.7	NA	27	0.71	120

Abbreviations: Max, maximum detected concentration; Med, median; Min, minimum detected concentration; NGD, natural gas development; NC, not calculated; No., number of samples; SD, standard deviation; %>MDL, percent greater than method detection limit; µg/m^3 micrograms per cubic meter; 95% UCL 95 percent upper confidence limit on the mean

[a]Samples collected at one site every 6 six days between 2008 and 2010.

[b]Samples collected at four separate sites in summer 2008 and one site in summer 2010.

[c]Calculated using EPA's ProUCL version 4.00.05 software (U. S. EPA 2010)

[d]Sum of 2,2,2-trimethylpentane, 2,2,4-trimethylpentane, 2,2-dimethylbutane, 2,3,4-trimethylpentane, 2,3-dimethylbutane, 2,3-dimethylpentane, 2,4-dimethylpentane, 2-methylheptane, 2-methylhexane, 2-methylpentane, 3-methylheptane, 3-methylhexane, 3-methylpentane, cyclopentane, isopentane, methylcyclopentane, n-heptane, n-octane

[e]Sum of n-decane, n-dodecane, n-tridecane, n-undecane

[f]Sum of m-diethylbenzene, m-ethyltoluene, o-ethyltoluene, p-diethylbenzene, p-ethyltoluene

Table 2: Detection frequencies of hydrocarbons without toxicity values detected in NGD area or well completion samples.

Hydrocarbon	NGD Area Sample[a] Detection Frequency (%)	Well Completion Sample[b] Detection Frequency (%)
1-Dodecene	36	81
1-Heptene	94	100
1-Hexene	63	79
1-Nonene	52	94
1-Octene	29	75
1-Pentene	98	79
1-Tridecene	7	38
1-Undecene	28	81
2-Ethyl-1-butene	1	0
2-Methyl-1-butene	29	44
2-Methyl-1-pentene	1	6
2-Methyl-2-butene	36	69
3-Methyl-1-butene	6	6
4-Methyl-1-pentene	16	69
Acetylene	100	92
a-Pinene	63	100
b-Pinene	10	44
cis-2-Butene	58	75
cis-2-Hexene	13	81
cis-2-Pentene	38	54
Cyclopentene	44	94
Ethane	100	100
Ethylene	100	100
Isobutane	100	100
Isobutene/1-Butene	73	44
Isoprene	71	96
n-Butane	98	100
Propane	100	100
Propyne	1	0
trans-2-Butene	80	75
trans-2-Hexene	1	6
trans-2-Pentene	55	83

Abbreviations: NGD, natural gas development
[a]Samples collected at one site every 6 six days between 2008 and 2010.
[b]Samples collected at four separate sites in summer 2008 and one site in summer 2010.

Table 3: Chronic and subchronic reference concentrations, critical effects, and major effects for hydrocarbons in quantitative risk assessment

Hydrocarbon	Chronic		Subchronic		Critical Effect/ Target Organ	Other Effects
	RfC ($\mu g/m^3$)	Source	RfC ($\mu g/m^3$)	Source		
1,2,3-Trimethylbenzene	5.00E+00	PPTRV	5.00E+01	PPTRV	neurological	respiratory, hematological
1,3,5-Trimethylbenzene	6.00E+00	PPTRV	1.00E+01	PPTRV	neurological	hematological
Isopropylbenzene	4.00E+02	IRIS	9.00E+01	HEAST	renal	neurological, respiratory
n-Hexane	7.00E+02	IRIS	2.00E+03	PPTRV	neurological	-
n-Nonane	2.00E+02	PPTRV	2.00E+03	PPTRV	neurological	respiratory
n-Pentane	1.00E+03	PPTRV	1.00E+04	PPTRV	neurological	-
Styrene	1.00E+03	IRIS	3.00E+03	HEAST	neurological	-
Toluene	5.00E+03	IRIS	5.00E+03	PPTRV	neurological	developmental, respiratory
Xylenes, total	1.00E+02	IRIS	4.00E+02	PPTRV	neurological	developmental, respiratory
n-propylbenzene	1.00E+03	PPTRV	1.00E+03	Chronic RfC PPTRV	developmental	Neurological
1,2,4-Trimethylbenzene	7.00E+00	PPTRV	7.00E+01	PPTRV	decrease in blood clotting time	neurological, respiratory
1,3-Butadiene	2.00E+00	IRIS	2.00E+00	Chronic RfC IRIS	reproductive	neurological, respiratory
Propylene	3.00E+03	CalEPA	1.00E+03	Chronic RfC CalEPA	respiratory	-
Benzene	3.00E+01	ATSDR	8.00E+01	PPTRV	decreased lymphocyte count	neurological, developmental, reproductive
Ethylbenzene	1.00E+03	ATSDR	9.00E+03	PPTRV	auditory	neurological, respiratory, renal
Cyclohexane	6.00E+03	IRIS	1.80E+04	PPTRV	developmental	neurological
Methylcyclohexane	3.00E+03	HEAST	3.00E+03	HEAST	renal	-
Aliphatic hydrocarbons $C_5 – C_8$[a]	6E+02	PPTRV	2.7E+04	PPTRV	neurological	-
Aliphatic hydrocarbons $C_9 – C_{18}$	1E+02	PPTRV	1E+02	PPTRV	respiratory	-
Aromatic hydrocarbons $C_9 – C_{18}$[b]	1E+02	PPTRV	1E+03	PPRTV	decreased maternal body weight	respiratory

Abbreviations: 95%UCL, 95 percent upper confidence limit; CalEPA, California Environmental Protection Agency; HEAST, EPA Health Effects Assessment Summary Tables 1997; HQ, hazard quotient; IRIS, Integrated Risk Information System; Max, maximum; PPTRV, EPA Provisional Peer-Reviewed Toxicity Value; RfC, reference concentration; $\mu g/m^3$, micrograms per cubic meter. Data from CalEPA 2011; IRIS (US EPA 2011a); ORNL 2011.

[a]Based on PPTRV for commercial hexane.

[b]Based on PPTRV for high flash naphtha.

Table 4: Chronic hazard quotients and hazard indices for residents living > ½ mile from wells and residents living ≤ ½ mile from wells.

Hydrocarbon	> ½ mile		≤ ½ mile	
	Chronic HQ based on median Concentration	Chronic HQ based on 95% UCL of mean concentration	Chronic HQ based on median Concentration	Chronic HQ based on 95% UCL of mean concentration
1,2,3-Trimethylbenzene	2.09E-02	1.90E-02	2.87E-02	5.21E-02
1,2,4-Trimethylbenzene	2.51E-02	4.22E-02	3.64E-02	2.01E-01
1,3,5-Trimethylbenzene	1.96E-02	2.80E-02	3.00E-02	1.99E-01
1,3-Butadiene	5.05E-02	2.23E-02	5.05E-02	2.25E-02
Benzene	3.03E-02	5.40E-02	3.32E-02	8.70E-02
Cyclohexane	3.40E-04	9.98E-04	3.67E-04	1.46E-03
Ethylbenzene	1.63E-04	3.98E-04	1.95E-04	3.23E-03
Isopropylbenzene	3.68E-04	1.78E-04	3.90E-04	3.05E-04
Methylcyclohexane	1.18E-03	2.00E-03	1.36E-03	5.32E-03
n-Hexane	5.49E-03	9.23E-03	5.76E-03	1.47E-02
n-Nonane	2.11E-03	3.14E-03	2.95E-03	2.31E-02
n-Pentane	8.71E-03	1.32E-02	8.79E-03	2.39E-02
n-propylbenzene	9.95E-05	9.59E-05	1.28E-04	2.64E-04
Propylene	1.09E-04	1.27E-04	1.10E-04	1.30E-04
Styrene	1.43E-04	1.25E-04	1.42E-04	4.32E-04
Toluene	3.40E-04	9.28E-04	4.06E-04	1.86E-03
Xylenes, total	1.16E-02	1.57E-02	1.54E-02	1.71E-01
Aliphatic hydrocarbons $C_5 – C_8$	4.63E-02	7.02E-02	4.87E-02	1.36E-01
Aliphatic hydrocarbons $C_9 – C_{18}$	1.22E-02	1.35E-01	1.58E-02	1.83E-01
Aromatic hydrocarbons $C_9 – C_{18}$	5.44E-03	6.67E-03	7.12E-03	2.04E-02
Total Hazard Index	2E-01	4E-01	3E-01	1E+00
Neuorological EffectsHazard Index[a]	2E-01	3E-01	3E-01	9E-01
Respiratory Effects Hazard Index[b]	1E-01	2E-02	2E-02	7E-01
Hematogical Effects Hazard Index[c]	1E-01	1E-01	1E-01	5E-01
Developmental Effects Hazard Index[d]	4E-02	7E-02	5E-02	3E-01

Abbreviations: 95%UCL, 95 percent upper confidence limit; HQ, hazard quotient;
[a]Sum of HQs for hydrocarbons with neurological effects: 1,2,3-Trimethylbenzene, 1,2,4-Trimethylbenzene, 1,3,5-Trimethylbenzene, 1,3-butadiene, benzene, cyclohexane, ethylbenzene, isopropylbenzene, n-hexane, n-nonane, n-pentane, n-propylbenzene, styrene, toluene, xylenes, aliphatic C_5-C_8 hydrocarbons.
[b]Sum of HQs for hydrocarbons with respiratory effects: 1,2,3-Trimethylbenzene, 1,2,4-Trimethylbenzene, 1,3-butadiene, ethylbenzene, isopropylbenzene, n-nonane, propylene, toluene, xylenes, aliphatic C_9-C_{18} hydrocarbons, aromatic C_9-C_{18} hydrocarbons
[c]Sum of HQs for hydrocarbons with hematological effects: 1,2,3-trimethylbenzene, 1,2,4-trimethylbenzene, 1,3,5-trimethylbenzene, benzene
[d]Sum of HQs for hydrocarbons with developmental effects: benzene, cyclohexane, toluene, and xylenes

Table 5: Subchronic hazard quotients and hazard indices residents living > ½ mile from wells and residents living ≤ ½ mile from wells.

	> ½ mile		≤ ½ mile	
Hydrocarbon (µg/m^3)	Subchronic HQ based on median concentration	Subchronic HQ based on 95% UCL of mean concentration	Subchronic HQ based on median concentration	Subchronic HQ based on 95% UCL of mean concentration
1,2,3-Trimethylbenzene	2.09E-03	1.90E-03	1.67E-02	6.40E-02
1,2,4-Trimethylbenzene	2.51E-03	4.22E-03	2.38E-02	3.02E-01
1,3,5-Trimethylbenzene	1.18E-02	1.68E-02	1.29E-01	1.95E+00
1,3-Butadiene	5.04E-02	2.23E-02	5.25E-02	8.30E-02
Benzene	1.14E-02	2.02E-02	3.25E-02	2.55E-01
Cyclohexane	1.13E-04	3.33E-04	2.93E-04	3.24E-03
Ethylbenzene	1.81E-05	4.42E-05	8.56E-05	5.96E-03
Isopropylbenzene	1.63E-03	7.92E-04	3.62E-03	1.14E-02
Methylcyclohexane	1.18E-03	2.01E-03	4.67E-03	6.47E-02
n-Hexane	1.92E-03	3.23E-03	3.86E-03	3.98E-02
n-Nonane	2.11E-04	3.14E-04	1.80E-03	3.78E-02
n-Pentane	8.71E-04	1.32E-03	1.05E-03	2.13E-02
n-propylbenzene	9.95E-05	9.57E-05	6.36E-04	3.26E-03
Propylene	1.43E-04	3.80E-04	4.12E-04	6.02E-04
Styrene	5.68E-04	4.16E-05	4.00E-06	1.97E-03
Toluene	4.18E-05	9.28E-04	2.46E-04	1.84E-02
Xylenes, total	2.91E-03	3.93E-03	2.05E-02	7.21E-01
Aliphatic hydrocarbons C_5 – C_8	1.07E-03	1.63E-03	2.07E-03	2.89E-02
Aliphatic hydrocarbons C_9 – C_{18}	1.3E-02	1.41E-01	7.9E-02	1.03E-00
Aromatic hydrocarbons C_9 – C_{18}	6.00E-04	6.95E-04	3.7E-03	2.64E-02
Total Hazard Index	1E-01	2E-01	4E-01	5E+00
Neurological EffectsHazard Index[a]	9E-02	8E-02	3E-01	4E+00
Respiratory Effects Hazard Index[b]	7E-02	2E-01	2E-01	2E+00
Hematogical Effects Hazard Index[c]	3E-02	4E-02	2E-01	3E+00
Developmental Effects Hazard Index[d]	1E-02	3E-02	5E-02	1E+00

Abbreviations: 95%UCL, 95 percent upper confidence limit; HQ, hazard quotient;

[a]Sum of HQs for hydrocarbons with neurological effects: 1,2,3-Trimethylbenzene, 1,2,4-Trimethylbenzene, 1,3,5-Trimethylbenzene, 1,3-butadiene, benzene, cyclohexane, ethylbenzene, isopropylbenzene, n-hexane, n-nonane, n-pentane, n-propylbenzene, styrene, toluene, xylenes, aliphatic C_5-C_8 hydrocarbons.

[b]Sum of HQs for hydrocarbons with respiratory effects: 1,2,3-Trimethylbenzene, 1,2,4-Trimethylbenzene, 1,3-butadiene, ethylbenzene, isopropylbenzene, n-nonane, propylene, toluene, xylenes, aliphatic C_9-C_{18} hydrocarbons, aromatic C_9-C_{18} hydrocarbons

[c]Sum of HQs for hydrocarbons with hematological effects: 1,2,3-trimethylbenzene, 1,2,4-trimethylbenzene, 1,3,5-trimethylbenzene, benzene

[d]Sum of HQs for hydrocarbons with developmental effects: benzene, cyclohexane, toluene, and xylenes

Table 6: Excess cancer risks for residents living > ½ mile from wells and residents living ≤ ½ mile from wells

	WOE				> ½ mile		≤ ½ mile	
Hydrocarbon	IRIS	IARC	Unit Risk (μg/m^3)	Source	Cancer risk based on median concentration	Cancer risk based on 95% UCL of mean concentration	Cancer risk based on median concentration	Cancer risk based on 95% UCL of mean concentration
1,3-Butadiene	B2	1	3.00E-05	IRIS	1.30E-06	5.73E-07	1.30E-06	6.54E-07
Benzene	A	1	7.80E-06	IRIS	3.03E-06	5.40E-06	3.33E-06	8.74E-06
Ethylbenzene	NC	2B	2.50E-06	CalEPA	1.75E-07	4.26E-07	2.09E-07	3.48E-06
Styrene	NC	2B	5.00E-07	CEP	3.10E-08	2.70E-08	3.00E-08	9.30E-08
Cumulative cancer risk					5E-06	6-06	5E-06	1E-05

Abbreviations: 95%UCL, 95 percent upper confidence limit; CalEPA, California Environmental Protection Agency; CEP, (Cadwell et al. 1998); IARC, International Agency for Research on Cancer; IRIS, Integrated Risk Information System; Max, maximum; NC, not calculated; WOE, weight of evidence; μg/m^3, micrograms per cubic meter. Data from CalEPA 2011; IRIS (US EPA 2011).

1

Historical Overview of Climate Change Science

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Executive Summary

Awareness and a partial understanding of most of the interactive processes in the Earth system that govern climate and climate change predate the IPCC, often by many decades. A deeper understanding and quantification of these processes and their incorporation in climate models have progressed rapidly since the IPCC First Assessment Report in 1990.

As climate science and the Earth's climate have continued to evolve over recent decades, increasing evidence of anthropogenic influences on climate change has been found. Correspondingly, the IPCC has made increasingly more definitive statements about human impacts on climate.

Debate has stimulated a wide variety of climate change research. The results of this research have refined but not significantly redirected the main scientific conclusions from the sequence of IPCC assessments.

1.1 Overview of the Chapter

To better understand the science assessed in this Fourth Assessment Report (AR4), it is helpful to review the long historical perspective that has led to the current state of climate change knowledge. This chapter starts by describing the fundamental nature of earth science. It then describes the history of climate change science using a wide-ranging subset of examples, and ends with a history of the IPCC.

The concept of this chapter is new. There is no counterpart in previous IPCC assessment reports for an introductory chapter providing historical context for the remainder of the report. Here, a restricted set of topics has been selected to illustrate key accomplishments and challenges in climate change science. The topics have been chosen for their significance to the IPCC task of assessing information relevant for understanding the risks of human-induced climate change, and also to illustrate the complex and uneven pace of scientific progress.

In this chapter, the time frame under consideration stops with the publication of the Third Assessment Report (TAR; IPCC, 2001a). Developments subsequent to the TAR are described in the other chapters of this report, and we refer to these chapters throughout this first chapter.

1.2 The Nature of Earth Science

Science may be stimulated by argument and debate, but it generally advances through formulating hypotheses clearly and testing them objectively. This testing is the key to science. In fact, one philosopher of science insisted that to be genuinely scientific, a statement must be susceptible to testing that could potentially show it to be false (Popper, 1934). In practice, contemporary scientists usually submit their research findings to the scrutiny of their peers, which includes disclosing the methods that they use, so their results can be checked through replication by other scientists. The insights and research results of individual scientists, even scientists of unquestioned genius, are thus confirmed or rejected in the peer-reviewed literature by the combined efforts of many other scientists. It is not the belief or opinion of the scientists that is important, but rather the results of this testing. Indeed, when Albert Einstein was informed of the publication of a book entitled *100 Authors Against Einstein*, he is said to have remarked, 'If I were wrong, then one would have been enough!' (Hawking, 1988); however, that one opposing scientist would have needed proof in the form of testable results.

Thus science is inherently self-correcting; incorrect or incomplete scientific concepts ultimately do not survive repeated testing against observations of nature. Scientific theories are ways of explaining phenomena and providing insights that can be evaluated by comparison with physical reality. Each successful prediction adds to the weight of evidence supporting the theory, and any unsuccessful prediction demonstrates that the underlying theory is imperfect and requires improvement or abandonment. Sometimes, only certain kinds of questions tend to be asked about a scientific phenomenon until contradictions build to a point where a sudden change of paradigm takes place (Kuhn, 1996). At that point, an entire field can be rapidly reconstructed under the new paradigm.

Despite occasional major paradigm shifts, the majority of scientific insights, even unexpected insights, tend to emerge incrementally as a result of repeated attempts to test hypotheses as thoroughly as possible. Therefore, because almost every new advance is based on the research and understanding that has gone before, science is cumulative, with useful features retained and non-useful features abandoned. Active research scientists, throughout their careers, typically spend large fractions of their working time studying in depth what other scientists have done. Superficial or amateurish acquaintance with the current state of a scientific research topic is an obstacle to a scientist's progress. Working scientists know that a day in the library can save a year in the laboratory. Even Sir Isaac Newton (1675) wrote that if he had 'seen further it is by standing on the shoulders of giants'. Intellectual honesty and professional ethics call for scientists to acknowledge the work of predecessors and colleagues.

The attributes of science briefly described here can be used in assessing competing assertions about climate change. Can the statement under consideration, in principle, be proven false? Has it been rigorously tested? Did it appear in the peer-reviewed literature? Did it build on the existing research record where appropriate? If the answer to any of these questions is no, then less credence should be given to the assertion until it is tested and independently verified. The IPCC assesses the scientific literature to create a report based on the best available science (Section 1.6). It must be acknowledged, however, that the IPCC also contributes to science by identifying the key uncertainties and by stimulating and coordinating targeted research to answer important climate change questions.

Frequently Asked Question 1.1

What Factors Determine Earth's Climate?

The climate system is a complex, interactive system consisting of the atmosphere, land surface, snow and ice, oceans and other bodies of water, and living things. The atmospheric component of the climate system most obviously characterises climate; climate is often defined as 'average weather'. Climate is usually described in terms of the mean and variability of temperature, precipitation and wind over a period of time, ranging from months to millions of years (the classical period is 30 years). The climate system evolves in time under the influence of its own internal dynamics and due to changes in external factors that affect climate (called 'forcings'). External forcings include natural phenomena such as volcanic eruptions and solar variations, as well as human-induced changes in atmospheric composition. Solar radiation powers the climate system. There are three fundamental ways to change the radiation balance of the Earth: 1) by changing the incoming solar radiation (e.g., by changes in Earth's orbit or in the Sun itself); 2) by changing the fraction of solar radiation that is reflected (called 'albedo'; e.g., by changes in cloud cover, atmospheric particles or vegetation); and 3) by altering the longwave radiation from Earth back towards space (e.g., by changing greenhouse gas concentrations). Climate, in turn, responds directly to such changes, as well as indirectly, through a variety of feedback mechanisms.

The amount of energy reaching the top of Earth's atmosphere each second on a surface area of one square metre facing the Sun during daytime is about 1,370 Watts, and the amount of energy per square metre per second averaged over the entire planet is one-quarter of this (see Figure 1). About 30% of the sunlight that reaches the top of the atmosphere is reflected back to space. Roughly two-thirds of this reflectivity is due to clouds and small particles in the atmosphere known as 'aerosols'. Light-coloured areas of Earth's surface – mainly snow, ice and deserts – reflect the remaining one-third of the sunlight. The most dramatic change in aerosol-produced reflectivity comes when major volcanic eruptions eject material very high into the atmosphere. Rain typically

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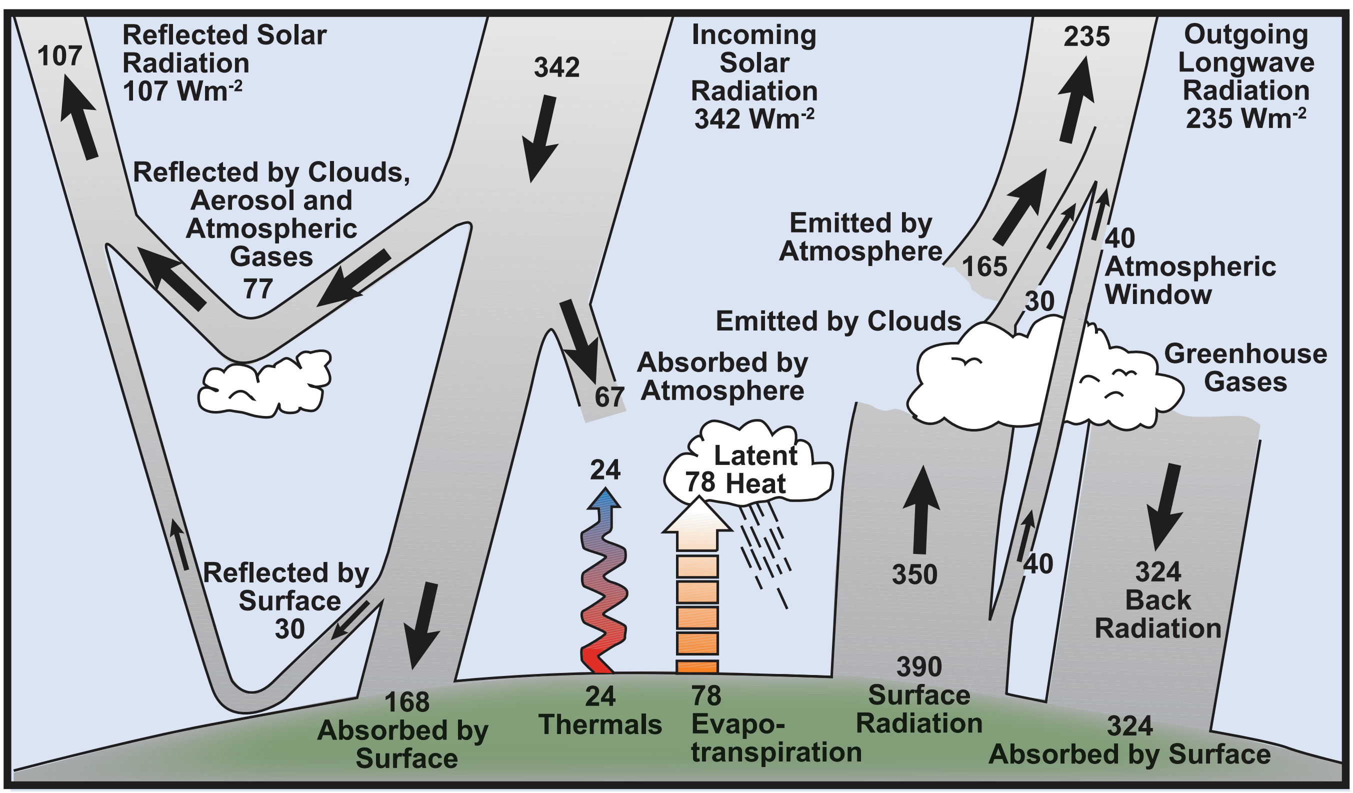


FAQ 1.1, Figure 1. *Estimate of the Earth's annual and global mean energy balance. Over the long term, the amount of incoming solar radiation absorbed by the Earth and atmosphere is balanced by the Earth and atmosphere releasing the same amount of outgoing longwave radiation. About half of the incoming solar radiation is absorbed by the Earth's surface. This energy is transferred to the atmosphere by warming the air in contact with the surface (thermals), by evapotranspiration and by longwave radiation that is absorbed by clouds and greenhouse gases. The atmosphere in turn radiates longwave energy back to Earth as well as out to space. Source: Kiehl and Trenberth (1997).*

clears aerosols out of the atmosphere in a week or two, but when material from a violent volcanic eruption is projected far above the highest cloud, these aerosols typically influence the climate for about a year or two before falling into the troposphere and being carried to the surface by precipitation. Major volcanic eruptions can thus cause a drop in mean global surface temperature of about half a degree celsius that can last for months or even years. Some man-made aerosols also significantly reflect sunlight.

The energy that is not reflected back to space is absorbed by the Earth's surface and atmosphere. This amount is approximately 240 Watts per square metre (W m^{-2}). To balance the incoming energy, the Earth itself must radiate, on average, the same amount of energy back to space. The Earth does this by emitting outgoing longwave radiation. Everything on Earth emits longwave radiation continuously. That is the heat energy one feels radiating out from a fire; the warmer an object, the more heat energy it radiates. To emit 240 W m^{-2}, a surface would have to have a temperature of around –19°C. This is much colder than the conditions that actually exist at the Earth's surface (the global mean surface temperature is about 14°C). Instead, the necessary –19°C is found at an altitude about 5 km above the surface.

The reason the Earth's surface is this warm is the presence of greenhouse gases, which act as a partial blanket for the longwave radiation coming from the surface. This blanketing is known as the natural greenhouse effect. The most important greenhouse gases are water vapour and carbon dioxide. The two most abundant constituents of the atmosphere – nitrogen and oxygen – have no such effect. Clouds, on the other hand, do exert a blanketing effect similar to that of the greenhouse gases; however, this effect is offset by their reflectivity, such that on average, clouds tend to have a cooling effect on climate (although locally one can feel the warming effect: cloudy nights tend to remain warmer than clear nights because the clouds radiate longwave energy back down to the surface). Human activities intensify the blanketing effect through the release of greenhouse gases. For instance, the amount of carbon dioxide in the atmosphere has increased by about 35% in the industrial era, and this increase is known to be due to human activities, primarily the combustion of fossil fuels and removal of forests. Thus, humankind has dramatically altered the chemical composition of the global atmosphere with substantial implications for climate.

Because the Earth is a sphere, more solar energy arrives for a given surface area in the tropics than at higher latitudes, where sunlight strikes the atmosphere at a lower angle. Energy is transported from the equatorial areas to higher latitudes via atmospheric and oceanic circulations, including storm systems. Energy is also required to evaporate water from the sea or land surface, and this energy, called latent heat, is released when water vapour condenses in clouds (see Figure 1). Atmospheric circulation is primarily driven by the release of this latent heat. Atmospheric circulation in turn drives much of the ocean circulation through the action of winds on the surface waters of the ocean, and through changes in the ocean's surface temperature and salinity through precipitation and evaporation.

Due to the rotation of the Earth, the atmospheric circulation patterns tend to be more east-west than north-south. Embedded in the mid-latitude westerly winds are large-scale weather systems that act to transport heat toward the poles. These weather systems are the familiar migrating low- and high-pressure systems and their associated cold and warm fronts. Because of land-ocean temperature contrasts and obstacles such as mountain ranges and ice sheets, the circulation system's planetary-scale atmospheric waves tend to be geographically anchored by continents and mountains although their amplitude can change with time. Because of the wave patterns, a particularly cold winter over North America may be associated with a particularly warm winter elsewhere in the hemisphere. Changes in various aspects of the climate system, such as the size of ice sheets, the type and distribution of vegetation or the temperature of the atmosphere or ocean will influence the large-scale circulation features of the atmosphere and oceans.

There are many feedback mechanisms in the climate system that can either amplify ('positive feedback') or diminish ('negative feedback') the effects of a change in climate forcing. For example, as rising concentrations of greenhouse gases warm Earth's climate, snow and ice begin to melt. This melting reveals darker land and water surfaces that were beneath the snow and ice, and these darker surfaces absorb more of the Sun's heat, causing more warming, which causes more melting, and so on, in a self-reinforcing cycle. This feedback loop, known as the 'ice-albedo feedback', amplifies the initial warming caused by rising levels of greenhouse gases. Detecting, understanding and accurately quantifying climate feedbacks have been the focus of a great deal of research by scientists unravelling the complexities of Earth's climate.

A characteristic of Earth sciences is that Earth scientists are unable to perform controlled experiments on the planet as a whole and then observe the results. In this sense, Earth science is similar to the disciplines of astronomy and cosmology that cannot conduct experiments on galaxies or the cosmos. This is an important consideration, because it is precisely such whole-Earth, system-scale experiments, incorporating the full complexity of interacting processes and feedbacks, that might ideally be required to fully verify or falsify climate change hypotheses (Schellnhuber et al., 2004). Nevertheless, countless empirical tests of numerous different hypotheses have built up a massive body of Earth science knowledge. This repeated testing has refined the understanding of numerous aspects of the climate system, from deep oceanic circulation to stratospheric chemistry. Sometimes a combination of observations and models can be used to test planetary-scale hypotheses. For example, the global cooling and drying of the atmosphere observed after the eruption of Mt. Pinatubo (Section 8.6) provided key tests of particular aspects of global climate models (Hansen et al., 1992).

Another example is provided by past IPCC projections of future climate change compared to current observations. Figure 1.1 reveals that the model projections of global average temperature from the First Assessment Report (FAR; IPCC, 1990) were higher than those from the Second Assessment Report (SAR; IPCC, 1996). Subsequent observations (Section 3.2) showed that the evolution of the actual climate system fell midway between the FAR and the SAR 'best estimate' projections and were within or near the upper range of projections from the TAR (IPCC, 2001a).

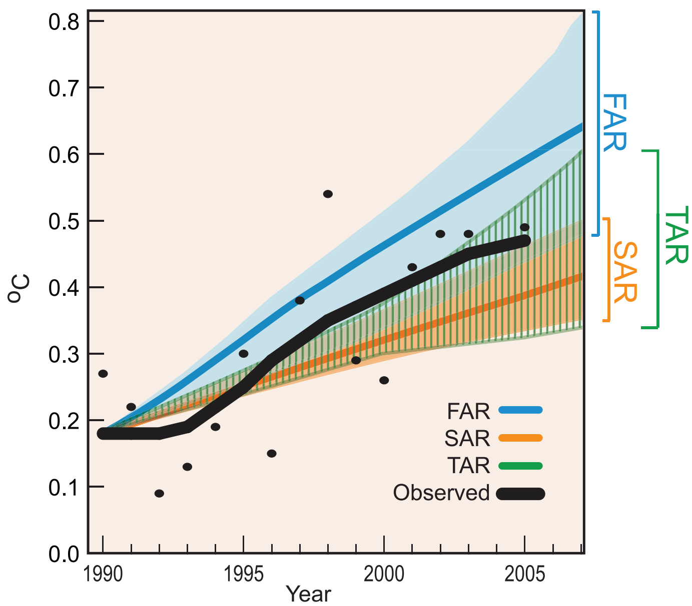


Figure 1.1. *Yearly global average surface temperature (Brohan et al., 2006), relative to the mean 1961 to 1990 values, and as projected in the FAR (IPCC, 1990), SAR (IPCC, 1996) and TAR (IPCC, 2001a). The 'best estimate' model projections from the FAR and SAR are in solid lines with their range of estimated projections shown by the shaded areas. The TAR did not have 'best estimate' model projections but rather a range of projections. Annual mean observations (Section 3.2) are depicted by black circles and the thick black line shows decadal variations obtained by smoothing the time series using a 13-point filter.*

Not all theories or early results are verified by later analysis. In the mid-1970s, several articles about possible global cooling appeared in the popular press, primarily motivated by analyses indicating that Northern Hemisphere (NH) temperatures had decreased during the previous three decades (e.g., Gwynne, 1975). In the peer-reviewed literature, a paper by Bryson and Dittberner (1976) reported that increases in carbon dioxide (CO_2) should be associated with a decrease in global temperatures. When challenged by Woronko (1977), Bryson and Dittberner (1977) explained that the cooling projected by their model was due to aerosols (small particles in the atmosphere) produced by the same combustion that caused the increase in CO_2. However, because aerosols remain in the atmosphere only a short time compared to CO_2, the results were not applicable for long-term climate change projections. This example of a prediction of global cooling is a classic illustration of the self-correcting nature of Earth science. The scientists involved were reputable researchers who followed the accepted paradigm of publishing in scientific journals, submitting their methods and results to the scrutiny of their peers (although the peer-review did not catch this problem), and responding to legitimate criticism.

A recurring theme throughout this chapter is that climate science in recent decades has been characterised by the increasing rate of advancement of research in the field and by the notable evolution of scientific methodology and tools, including the models and observations that support and enable the research. During the last four decades, the rate at which scientists have added to the body of knowledge of atmospheric and oceanic processes has accelerated dramatically. As scientists incrementally increase the totality of knowledge, they publish their results in peer-reviewed journals. Between 1965 and 1995, the number of articles published per year in atmospheric science journals tripled (Geerts, 1999). Focusing more narrowly, Stanhill (2001) found that the climate change science literature grew approximately exponentially with a doubling time of 11 years for the period 1951 to 1997. Furthermore, 95% of all the climate change science literature since 1834 was published after 1951. Because science is cumulative, this represents considerable growth in the knowledge of climate processes and in the complexity of climate research. An important example of this is the additional physics incorporated in climate models over the last several decades, as illustrated in Figure 1.2. As a result of the cumulative nature of science, climate science today is an interdisciplinary synthesis of countless tested and proven physical processes and principles painstakingly compiled and verified over several centuries of detailed laboratory measurements, observational experiments and theoretical analyses; and is now far more wide-ranging and physically comprehensive than was the case only a few decades ago.

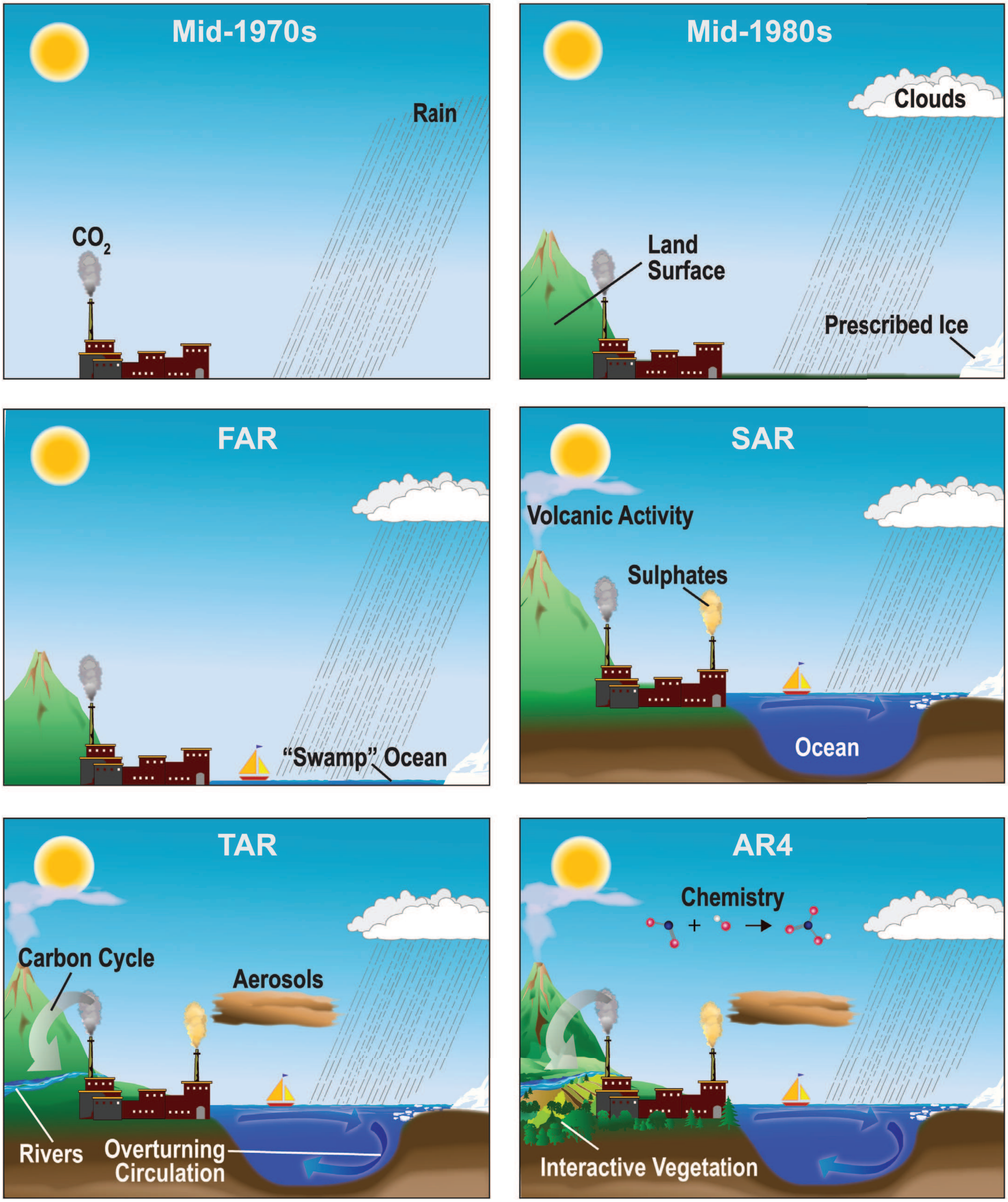


Figure 1.2. *The complexity of climate models has increased over the last few decades. The additional physics incorporated in the models are shown pictorially by the different features of the modelled world.*

1.3 Examples of Progress in Detecting and Attributing Recent Climate Change

1.3.1 The Human Fingerprint on Greenhouse Gases

The high-accuracy measurements of atmospheric CO_2 concentration, initiated by Charles David Keeling in 1958, constitute the master time series documenting the changing composition of the atmosphere (Keeling, 1961, 1998). These data have iconic status in climate change science as evidence of the effect of human activities on the chemical composition of the global atmosphere (see FAQ 7.1). Keeling's measurements on Mauna Loa in Hawaii provide a true measure of the global carbon cycle, an effectively continuous record of the burning of fossil fuel. They also maintain an accuracy and precision that allow scientists to separate fossil fuel emissions from those due to the natural annual cycle of the biosphere, demonstrating a long-term change in the seasonal exchange of CO_2 between the atmosphere, biosphere and ocean. Later observations of parallel trends in the atmospheric abundances of the $^{13}CO_2$ isotope (Francey and Farquhar, 1982) and molecular oxygen (O_2) (Keeling and Shertz, 1992; Bender et al., 1996) uniquely identified this rise in CO_2 with fossil fuel burning (Sections 2.3, 7.1 and 7.3).

To place the increase in CO_2 abundance since the late 1950s in perspective, and to compare the magnitude of the anthropogenic increase with natural cycles in the past, a longer-term record of CO_2 and other natural greenhouse gases is needed. These data came from analysis of the composition of air enclosed in bubbles in ice cores from Greenland and Antarctica. The initial measurements demonstrated that CO_2 abundances were significantly lower during the last ice age than over the last 10 kyr of the Holocene (Delmas et al., 1980; Berner et al., 1980; Neftel et al., 1982). From 10 kyr before present up to the year 1750, CO_2 abundances stayed within the range 280 ± 20 ppm (Indermühle et al., 1999). During the industrial era, CO_2 abundance rose roughly exponentially to 367 ppm in 1999 (Neftel et al., 1985; Etheridge et al., 1996; IPCC, 2001a) and to 379 ppm in 2005 (Section 2.3.1; see also Section 6.4).

Direct atmospheric measurements since 1970 (Steele et al., 1996) have also detected the increasing atmospheric abundances of two other major greenhouse gases, methane (CH_4) and nitrous oxide (N_2O). Methane abundances were initially increasing at a rate of about 1% yr^{-1} (Graedel and McRae, 1980; Fraser et al., 1981; Blake et al., 1982) but then slowed to an average increase of 0.4% yr^{-1} over the 1990s (Dlugokencky et al., 1998) with the possible stabilisation of CH_4 abundance (Section 2.3.2). The increase in N_2O abundance is smaller, about 0.25% yr^{-1}, and more difficult to detect (Weiss, 1981; Khalil and Rasmussen, 1988). To go back in time, measurements were made from firn air trapped in snowpack dating back over 200 years, and these data show an accelerating rise in both CH_4 and N_2O into the 20th century (Machida et al., 1995; Battle et al., 1996). When ice core measurements extended the CH_4 abundance back 1 kyr, they showed a stable, relatively constant abundance of 700 ppb until the 19th century when a steady increase brought CH_4 abundances to 1,745 ppb in 1998 (IPCC, 2001a) and 1,774 ppb in 2005 (Section 2.3.2). This peak abundance is much higher than the range of 400 to 700 ppb seen over the last half-million years of glacial-interglacial cycles, and the increase can be readily explained by anthropogenic emissions. For N_2O the results are similar: the relative increase over the industrial era is smaller (15%), yet the 1998 abundance of 314 ppb (IPCC, 2001a), rising to 319 ppb in 2005 (Section 2.3.3), is also well above the 180-to-260 ppb range of glacial-interglacial cycles (Flückiger et al., 1999; see Sections 2.3, 6.2, 6.3, 6.4, 7.1 and 7.4)

Several synthetic halocarbons (chlorofluorocarbons (CFCs), hydrofluorocarbons, perfluorocarbons, halons and sulphur hexafluoride) are greenhouse gases with large global warming potentials (GWPs; Section 2.10). The chemical industry has been producing these gases and they have been leaking into the atmosphere since about 1930. Lovelock (1971) first measured CFC-11 ($CFCl_3$) in the atmosphere, noting that it could serve as an artificial tracer, with its north-south gradient reflecting the latitudinal distribution of anthropogenic emissions. Atmospheric abundances of all the synthetic halocarbons were increasing until the 1990s, when the abundance of halocarbons phased out under the Montreal Protocol began to fall (Montzka et al., 1999; Prinn et al., 2000). In the case of synthetic halocarbons (except perfluoromethane), ice core research has shown that these compounds did not exist in ancient air (Langenfelds et al., 1996) and thus confirms their industrial human origin (see Sections 2.3 and 7.1).

At the time of the TAR scientists could say that the abundances of all the well-mixed greenhouse gases during the 1990s were greater than at any time during the last half-million years (Petit et al, 1999), and this record now extends back nearly one million years (Section 6.3). Given this daunting picture of increasing greenhouse gas abundances in the atmosphere, it is noteworthy that, for simpler challenges but still on a hemispheric or even global scale, humans have shown the ability to undo what they have done. Sulphate pollution in Greenland was reversed in the 1980s with the control of acid rain in North America and Europe (IPCC, 2001b), and CFC abundances are declining globally because of their phase-out undertaken to protect the ozone layer.

1.3.2 Global Surface Temperature

Shortly after the invention of the thermometer in the early 1600s, efforts began to quantify and record the weather. The first meteorological network was formed in northern Italy in 1653 (Kington, 1988) and reports of temperature observations were published in the earliest scientific journals (e.g., Wallis and Beale, 1669). By the latter part of the 19th century, systematic observations of the weather were being made in almost all inhabited areas of the world. Formal international coordination of meteorological observations from ships commenced in 1853 (Quetelet, 1854).

Inspired by the paper *Suggestions on a Uniform System of Meteorological Observations* (Buys-Ballot, 1872), the International Meteorological Organization (IMO) was formed in 1873. Its successor, the World Meteorological Organization (WMO), still works to promote and exchange standardised meteorological observations. Yet even with uniform observations, there are still four major obstacles to turning instrumental observations into accurate global time series: (1) access to the data in usable form; (2) quality control to remove or edit erroneous data points; (3) homogeneity assessments and adjustments where necessary to ensure the fidelity of the data; and (4) area-averaging in the presence of substantial gaps.

Köppen (1873, 1880, 1881) was the first scientist to overcome most of these obstacles in his quest to study the effect of changes in sunspots (Section 2.7). Much of his data came from Dove (1852), but wherever possible he used data directly from the original source, because Dove often lacked information about the observing methods. Köppen considered examination of the annual mean temperature to be an adequate technique for quality control of far distant stations. Using data from more than 100 stations, Köppen averaged annual observations into several major latitude belts and then area-averaged these into a near-global time series shown in Figure 1.3.

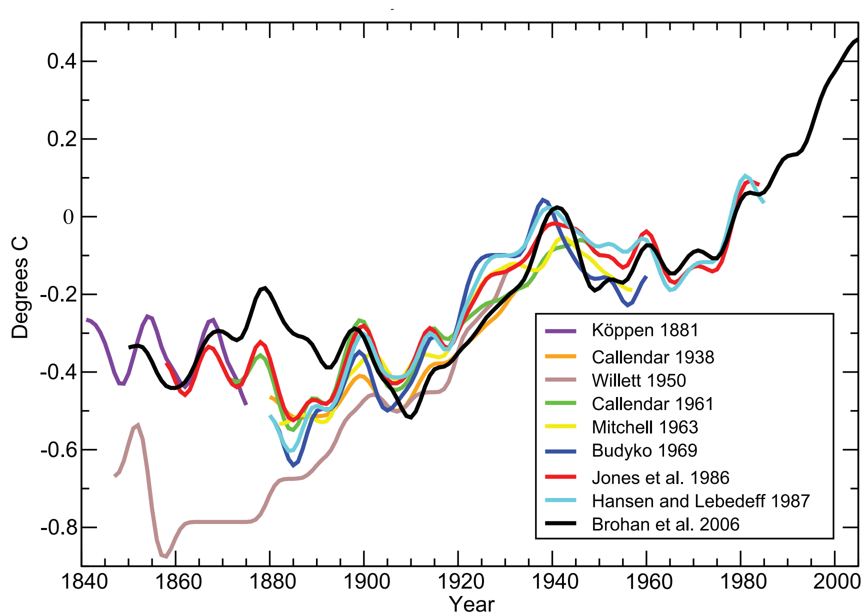


Figure 1.3. *Published records of surface temperature change over large regions. Köppen (1881) tropics and temperate latitudes using land air temperature. Callendar (1938) global using land stations. Willett (1950) global using land stations. Callendar (1961) 60°N to 60°S using land stations. Mitchell (1963) global using land stations. Budyko (1969) Northern Hemisphere using land stations and ship reports. Jones et al. (1986a,b) global using land stations. Hansen and Lebedeff (1987) global using land stations. Brohan et al. (2006) global using land air temperature and sea surface temperature data is the longest of the currently updated global temperature time series (Section 3.2). All time series were smoothed using a 13-point filter. The Brohan et al. (2006) time series are anomalies from the 1961 to 1990 mean (°C). Each of the other time series was originally presented as anomalies from the mean temperature of a specific and differing base period. To make them comparable, the other time series have been adjusted to have the mean of their last 30 years identical to that same period in the Brohan et al. (2006) anomaly time series.*

Callendar (1938) produced the next global temperature time series expressly to investigate the influence of CO_2 on temperature (Section 2.3). Callendar examined about 200 station records. Only a small portion of them were deemed defective, based on quality concerns determined by comparing differences with neighbouring stations or on homogeneity concerns based on station changes documented in the recorded metadata. After further removing two arctic stations because he had no compensating stations from the antarctic region, he created a global average using data from 147 stations.

Most of Callendar's data came from World Weather Records (WWR; Clayton, 1927). Initiated by a resolution at the 1923 IMO Conference, WWR was a monumental international undertaking producing a 1,196-page volume of monthly temperature, precipitation and pressure data from hundreds of stations around the world, some with data starting in the early 1800s. In the early 1960s, J. Wolbach had these data digitised (National Climatic Data Center, 2002). The WWR project continues today under the auspices of the WMO with the digital publication of decadal updates to the climate records for thousands of stations worldwide (National Climatic Data Center, 2005).

Willett (1950) also used WWR as the main source of data for 129 stations that he used to create a global temperature time series going back to 1845. While the resolution that initiated WWR called for the publication of long and homogeneous records, Willett took this mandate one step further by carefully selecting a subset of stations with as continuous and homogeneous a record as possible from the most recent update of WWR, which included data through 1940. To avoid over-weighting certain areas such as Europe, only one record, the best available, was included from each 10° latitude and longitude square. Station monthly data were averaged into five-year periods and then converted to anomalies with respect to the five-year period 1935 to 1939. Each station's anomaly was given equal weight to create the global time series.

Callendar in turn created a new near-global temperature time series in 1961 and cited Willett (1950) as a guide for some of his improvements. Callendar (1961) evaluated 600 stations with about three-quarters of them passing his quality checks. Unbeknownst to Callendar, a former student of Willett, Mitchell (1963), in work first presented in 1961, had created his own updated global temperature time series using slightly fewer than 200 stations and averaging the data into latitude bands. Landsberg and Mitchell (1961) compared Callendar's results with Mitchell's and stated that there was generally good agreement except in the data-sparse regions of the Southern Hemisphere.

Meanwhile, research in Russia was proceeding on a very different method to produce large-scale time series. Budyko (1969) used smoothed, hand-drawn maps of monthly temperature anomalies as a starting point. While restricted to analysis of the NH, this map-based approach not only allowed the inclusion of an increasing number of stations over time (e.g., 246 in 1881, 753 in 1913, 976 in 1940 and about 2,000 in 1960) but also the utilisation of data over the oceans (Robock, 1982).

Increasing the number of stations utilised has been a continuing theme over the last several decades with considerable effort being spent digitising historical station data as well as addressing the continuing problem of acquiring up-to-date data, as there can be a long lag between making an observation and the data getting into global data sets. During the 1970s and 1980s, several teams produced global temperature time series. Advances especially worth noting during this period include the extended spatial interpolation and station averaging technique of Hansen and Lebedeff (1987) and the Jones et al. (1986a,b) painstaking assessment of homogeneity and adjustments to account for discontinuities in the record of each of the thousands of stations in a global data set. Since then, global and national data sets have been rigorously adjusted for homogeneity using a variety of statistical and metadata-based approaches (Peterson et al., 1998).

One recurring homogeneity concern is potential urban heat island contamination in global temperature time series. This concern has been addressed in two ways. The first is by adjusting the temperature of urban stations to account for assessed urban heat island effects (e.g., Karl et al., 1988; Hansen et al., 2001). The second is by performing analyses that, like Callendar (1938), indicate that the bias induced by urban heat islands in the global temperature time series is either minor or non-existent (Jones et al., 1990; Peterson et al., 1999).

As the importance of ocean data became increasingly recognised, a major effort was initiated to seek out, digitise and quality-control historical archives of ocean data. This work has since grown into the International Comprehensive Ocean-Atmosphere Data Set (ICOADS; Worley et al., 2005), which has coordinated the acquisition, digitisation and synthesis of data ranging from transmissions by Japanese merchant ships to the logbooks of South African whaling boats. The amount of sea surface temperature (SST) and related data acquired continues to grow.

As fundamental as the basic data work of ICOADS was, there have been two other major advances in SST data. The first was adjusting the early observations to make them comparable to current observations (Section 3.2). Prior to 1940, the majority of SST observations were made from ships by hauling a bucket on deck filled with surface water and placing a thermometer in it. This ancient method eventually gave way to thermometers placed in engine cooling water inlets, which are typically located several metres below the ocean surface. Folland and Parker (1995) developed an adjustment model that accounted for heat loss from the buckets and that varied with bucket size and type, exposure to solar radiation, ambient wind speed and ship speed. They verified their results using time series of night marine air temperature. This adjusted the early bucket observations upwards by a few tenths of a degree celsius.

Most of the ship observations are taken in narrow shipping lanes, so the second advance has been increasing global coverage in a variety of ways. Direct improvement of coverage has been achieved by the internationally coordinated placement of drifting and moored buoys. The buoys began to be numerous enough to make significant contributions to SST analyses in the mid-1980s (McPhaden et al., 1998) and have subsequently increased to more than 1,000 buoys transmitting data at any one time. Since 1982, satellite data, anchored to *in situ* observations, have contributed to near-global coverage (Reynolds and Smith, 1994). In addition, several different approaches have been used to interpolate and combine land and ocean observations into the current global temperature time series (Section 3.2). To place the current instrumental observations into a longer historical context requires the use of proxy data (Section 6.2).

Figure 1.3 depicts several historical 'global' temperature time series, together with the longest of the current global temperature time series, that of Brohan et al. (2006; Section 3.2). While the data and the analysis techniques have changed over time, all the time series show a high degree of consistency since 1900. The differences caused by using alternate data sources and interpolation techniques increase when the data are sparser. This phenomenon is especially illustrated by the pre-1880 values of Willett's (1950) time series. Willett noted that his data coverage remained fairly constant after 1885 but dropped off dramatically before that time to only 11 stations before 1850. The high degree of agreement between the time series resulting from these many different analyses increases the confidence that the changes they are indicating are real.

Despite the fact that many recent observations are automatic, the vast majority of data that go into global surface temperature calculations – over 400 million individual readings of thermometers at land stations and over 140 million individual *in situ* SST observations – have depended on the dedication of tens of thousands of individuals for well over a century. Climate science owes a great debt to the work of these individual weather observers as well as to international organisations such as the IMO, WMO and the Global Climate Observing System, which encourage the taking and sharing of high-quality meteorological observations. While modern researchers and their institutions put a great deal of time and effort into acquiring and adjusting the data to account for all known problems and biases, century-scale global temperature time series would not have been possible without the conscientious work of individuals and organisations worldwide dedicated to quantifying and documenting their local environment (Section 3.2).

1.3.3 Detection and Attribution

Using knowledge of past climates to qualify the nature of ongoing changes has become a concern of growing importance during the last decades, as reflected in the successive IPCC reports. While linked together at a technical level, detection and attribution have separate objectives. Detection of climate change is the process of demonstrating that climate has changed in some defined statistical sense, without providing a reason for that change. Attribution of causes of climate change is the process of establishing the most likely causes for the detected change with some defined level of confidence. Using traditional approaches, unequivocal attribution would require controlled experimentation with our climate system. However, with no spare Earth with which to experiment, attribution of anthropogenic climate change must be pursued by: (a) detecting that the climate has changed (as defined above); (b) demonstrating that the detected change is consistent with computer model simulations of the climate change 'signal' that is calculated to occur in response to anthropogenic forcing; and (c) demonstrating that the detected change is not consistent with alternative, physically plausible explanations of recent climate change that exclude important anthropogenic forcings.

Both detection and attribution rely on observational data and model output. In spite of the efforts described in Section 1.3.2, estimates of century-scale natural climate fluctuations remain difficult to obtain directly from observations due to the relatively short length of most observational records and a lack of understanding of the full range and effects of the various and ongoing external influences. Model simulations with no changes in external forcing (e.g., no increases in atmospheric CO_2 concentration) provide valuable information on the natural internal variability of the climate system on time scales of years to centuries. Attribution, on the other hand, requires output from model runs that incorporate historical estimates of changes in key anthropogenic and natural forcings, such as well-mixed greenhouse gases, volcanic aerosols and solar irradiance. These simulations can be performed with changes in a single forcing only (which helps to isolate the climate effect of that forcing), or with simultaneous changes in a whole suite of forcings.

In the early years of detection and attribution research, the focus was on a single time series – the estimated global-mean changes in the Earth's surface temperature. While it was not possible to detect anthropogenic warming in 1980, Madden and Ramanathan (1980) and Hansen et al. (1981) predicted it would be evident at least within the next two decades. A decade later, Wigley and Raper (1990) used a simple energy-balance climate model to show that the observed change in global-mean surface temperature from 1867 to 1982 could not be explained by natural internal variability. This finding was later confirmed using variability estimates from more complex coupled ocean-atmosphere general circulation models (e.g., Stouffer et al., 1994).

As the science of climate change progressed, detection and attribution research ventured into more sophisticated statistical analyses that examined complex patterns of climate change. Climate change patterns or 'fingerprints' were no longer limited to a single variable (temperature) or to the Earth's surface. More recent detection and attribution work has made use of precipitation and global pressure patterns, and analysis of vertical profiles of temperature change in the ocean and atmosphere. Studies with multiple variables make it easier to address attribution issues. While two different climate forcings may yield similar changes in global mean temperature, it is highly unlikely that they will produce exactly the same 'fingerprint' (i.e., climate changes that are identical as a function of latitude, longitude, height, season and history over the 20th century).

Such model-predicted fingerprints of anthropogenic climate change are clearly statistically identifiable in observed data. The common conclusion of a wide range of fingerprint studies conducted over the past 15 years is that observed climate changes cannot be explained by natural factors alone (Santer et al., 1995, 1996a,b,c; Hegerl et al., 1996, 1997, 2000; Hasselmann, 1997; Barnett et al., 1999; Tett et al., 1999; Stott et al., 2000). A substantial anthropogenic influence is required in order to best explain the observed changes. The evidence from this body of work strengthens the scientific case for a discernible human influence on global climate.

1.4 Examples of Progress in Understanding Climate Processes

1.4.1 The Earth's Greenhouse Effect

The realisation that Earth's climate might be sensitive to the atmospheric concentrations of gases that create a greenhouse effect is more than a century old. Fleming (1998) and Weart (2003) provided an overview of the emerging science. In terms of the energy balance of the climate system, Edme Mariotte noted in 1681 that although the Sun's light and heat easily pass through glass and other transparent materials, heat from other sources (*chaleur de feu*) does not. The ability to generate an artificial warming of the Earth's surface was demonstrated in simple greenhouse experiments such as Horace Benedict de Saussure's experiments in the 1760s using a 'heliothermometer' (panes of glass covering a thermometer in a darkened box) to provide an early analogy to the greenhouse effect. It was a conceptual leap to recognise that the air itself could also trap thermal radiation. In 1824, Joseph Fourier, citing Saussure, argued 'the temperature [of the Earth] can be augmented by the interposition of the atmosphere, because heat in the state of light finds less resistance in penetrating the air, than in repassing into the air when converted into non-luminous heat'. In 1836, Pouillit followed up on Fourier's ideas and argued 'the atmospheric stratum…exercises a greater absorption upon the terrestrial than on the solar rays'. There was still no understanding of exactly what substance in the atmosphere was responsible for this absorption.

In 1859, John Tyndall (1861) identified through laboratory experiments the absorption of thermal radiation by complex molecules (as opposed to the primary bimolecular atmospheric constituents O_2 and molecular nitrogen). He noted that changes in the amount of any of the radiatively active constituents of the atmosphere such as water (H_2O) or CO_2 could have produced 'all the mutations of climate which the researches of geologists

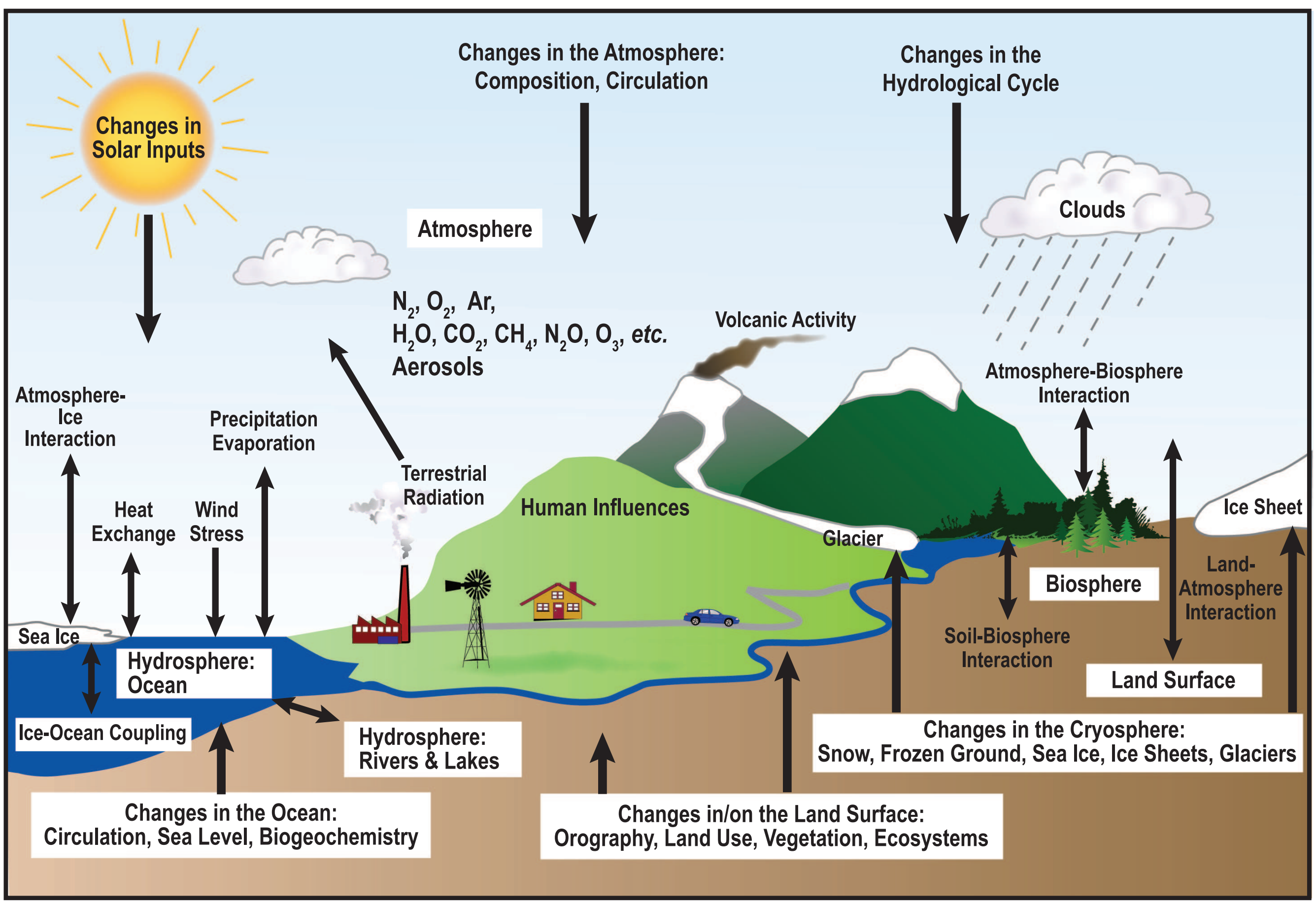
Frequently Asked Question 1.2

What is the Relationship between Climate Change and Weather?

Climate is generally defined as average weather, and as such, climate change and weather are intertwined. Observations can show that there have been changes in weather, and it is the statistics of changes in weather over time that identify climate change. While weather and climate are closely related, there are important differences. A common confusion between weather and climate arises when scientists are asked how they can predict climate 50 years from now when they cannot predict the weather a few weeks from now. The chaotic nature of weather makes it unpredictable beyond a few days. Projecting changes in climate (i.e., long-term average weather) due to changes in atmospheric composition or other factors is a very different and much more manageable issue. As an analogy, while it is impossible to predict the age at which any particular man will die, we can say with high confidence that the average age of death for men in industrialised countries is about 75. Another common confusion of these issues is thinking that a cold winter or a cooling spot on the globe is evidence against global warming. There are always extremes of hot and cold, although their frequency and intensity change as climate changes. But when weather is averaged over space and time, the fact that the globe is warming emerges clearly from the data.

Meteorologists put a great deal of effort into observing, understanding and predicting the day-to-day evolution of weather systems. Using physics-based concepts that govern how the atmosphere moves, warms, cools, rains, snows, and evaporates water, meteorologists are typically able to predict the weather successfully several days into the future. A major limiting factor to the predictability of weather beyond several days is a fundamental dynamical property of the atmosphere. In the 1960s, meteorologist Edward Lorenz discovered that very slight differences in initial conditions can produce very different forecast results.

(continued)



FAQ 1.2, Figure 1. *Schematic view of the components of the climate system, their processes and interactions.*

This is the so-called butterfly effect: a butterfly flapping its wings (or some other small phenomenon) in one place can, in principle, alter the subsequent weather pattern in a distant place. At the core of this effect is chaos theory, which deals with how small changes in certain variables can cause apparent randomness in complex systems.

Nevertheless, chaos theory does not imply a total lack of order. For example, slightly different conditions early in its history might alter the day a storm system would arrive or the exact path it would take, but the average temperature and precipitation (that is, climate) would still be about the same for that region and that period of time. Because a significant problem facing weather forecasting is knowing all the conditions at the start of the forecast period, it can be useful to think of climate as dealing with the background conditions for weather. More precisely, climate can be viewed as concerning the status of the entire Earth system, including the atmosphere, land, oceans, snow, ice and living things (see Figure 1) that serve as the global background conditions that determine weather patterns. An example of this would be an El Niño affecting the weather in coastal Peru. The El Niño sets limits on the probable evolution of weather patterns that random effects can produce. A La Niña would set different limits.

Another example is found in the familiar contrast between summer and winter. The march of the seasons is due to changes in the geographical patterns of energy absorbed and radiated away by the Earth system. Likewise, projections of future climate are shaped by fundamental changes in heat energy in the Earth system, in particular the increasing intensity of the greenhouse effect that traps heat near Earth's surface, determined by the amount of carbon dioxide and other greenhouse gases in the atmosphere. Projecting changes in climate due to changes in greenhouse gases 50 years from now is a very different and much more easily solved problem than forecasting weather patterns just weeks from now. To put it another way, long-term variations brought about by changes in the composition of the atmosphere are much more predictable than individual weather events. As an example, while we cannot predict the outcome of a single coin toss or roll of the dice, we can predict the statistical behaviour of a large number of such trials.

While many factors continue to influence climate, scientists have determined that human activities have become a dominant force, and are responsible for most of the warming observed over the past 50 years. Human-caused climate change has resulted primarily from changes in the amounts of greenhouse gases in the atmosphere, but also from changes in small particles (aerosols), as well as from changes in land use, for example. As climate changes, the probabilities of certain types of weather events are affected. For example, as Earth's average temperature has increased, some weather phenomena have become more frequent and intense (e.g., heat waves and heavy downpours), while others have become less frequent and intense (e.g., extreme cold events).

reveal'. In 1895, Svante Arrhenius (1896) followed with a climate prediction based on greenhouse gases, suggesting that a 40% increase or decrease in the atmospheric abundance of the trace gas CO_2 might trigger the glacial advances and retreats. One hundred years later, it would be found that CO_2 did indeed vary by this amount between glacial and interglacial periods. However, it now appears that the initial climatic change preceded the change in CO_2 but was enhanced by it (Section 6.4).

G. S. Callendar (1938) solved a set of equations linking greenhouse gases and climate change. He found that a doubling of atmospheric CO_2 concentration resulted in an increase in the mean global temperature of 2°C, with considerably more warming at the poles, and linked increasing fossil fuel combustion with a rise in CO_2 and its greenhouse effects: 'As man is now changing the composition of the atmosphere at a rate which must be very exceptional on the geological time scale, it is natural to seek for the probable effects of such a change. From the best laboratory observations it appears that the principal result of increasing atmospheric carbon dioxide… would be a gradual increase in the mean temperature of the colder regions of the Earth.' In 1947, Ahlmann reported a 1.3°C warming in the North Atlantic sector of the Arctic since the 19th century and mistakenly believed this climate variation could be explained entirely by greenhouse gas warming. Similar model predictions were echoed by Plass in 1956 (see Fleming, 1998): 'If at the end of this century, measurements show that the carbon dioxide content of the atmosphere has risen appreciably and at the same time the temperature has continued to rise throughout the world, it will be firmly established that carbon dioxide is an important factor in causing climatic change' (see Chapter 9).

In trying to understand the carbon cycle, and specifically how fossil fuel emissions would change atmospheric CO_2, the interdisciplinary field of carbon cycle science began. One of the first problems addressed was the atmosphere-ocean exchange of CO_2. Revelle and Suess (1957) explained why part of the emitted CO_2 was observed to accumulate in the atmosphere rather than being completely absorbed by the oceans. While CO_2 can be mixed rapidly into the upper layers of the ocean, the time to mix with the deep ocean is many centuries. By the time of the TAR, the interaction of climate change with the oceanic circulation and biogeochemistry was projected to reduce the fraction of anthropogenic CO_2 emissions taken up by the oceans in the future, leaving a greater fraction in the atmosphere (Sections 7.1, 7.3 and 10.4).

In the 1950s, the greenhouse gases of concern remained CO_2 and H_2O, the same two identified by Tyndall a century earlier. It was not until the 1970s that other greenhouse gases – CH_4, N_2O and CFCs – were widely recognised as important anthropogenic greenhouse gases (Ramanathan, 1975; Wang et al., 1976; Section 2.3). By the 1970s, the importance of aerosol-cloud effects in reflecting sunlight was known (Twomey, 1977), and atmospheric aerosols (suspended small particles) were being proposed as climate-forcing constituents. Charlson and others (summarised in Charlson et al., 1990) built a consensus that sulphate aerosols were, by themselves, cooling the Earth's surface by directly reflecting sunlight. Moreover, the increases in sulphate aerosols were anthropogenic and linked with the main source of CO_2, burning of fossil fuels (Section 2.4). Thus, the current picture of the atmospheric constituents driving climate change contains a much more diverse mix of greenhouse agents.

1.4.2 Past Climate Observations, Astronomical Theory and Abrupt Climate Changes

Throughout the 19th and 20th centuries, a wide range of geomorphology and palaeontology studies has provided new insight into the Earth's past climates, covering periods of hundreds of millions of years. The Palaeozoic Era, beginning 600 Ma, displayed evidence of both warmer and colder climatic conditions than the present; the Tertiary Period (65 to 2.6 Ma) was generally warmer; and the Quaternary Period (2.6 Ma to the present – the ice ages) showed oscillations between glacial and interglacial conditions. Louis Agassiz (1837) developed the hypothesis that Europe had experienced past glacial ages, and there has since been a growing awareness that long-term climate observations can advance the understanding of the physical mechanisms affecting climate change. The scientific study of one such mechanism – modifications in the geographical and temporal patterns of solar energy reaching the Earth's surface due to changes in the Earth's orbital parameters – has a long history. The pioneering contributions of Milankovitch (1941) to this astronomical theory of climate change are widely known, and the historical review of Imbrie and Imbrie (1979) calls attention to much earlier contributions, such as those of James Croll, originating in 1864.

The pace of palaeoclimatic research has accelerated over recent decades. Quantitative and well-dated records of climate fluctuations over the last 100 kyr have brought a more comprehensive view of how climate changes occur, as well as the means to test elements of the astronomical theory. By the 1950s, studies of deep-sea cores suggested that the ocean temperatures may have been different during glacial times (Emiliani, 1955). Ewing and Donn (1956) proposed that changes in ocean circulation actually could initiate an ice age. In the 1960s, the works of Emiliani (1969) and Shackleton (1967) showed the potential of isotopic measurements in deep-sea sediments to help explain Quaternary changes. In the 1970s, it became possible to analyse a deep-sea core time series of more than 700 kyr, thereby using the last reversal of the Earth's magnetic field to establish a dated chronology. This deep-sea observational record clearly showed the same periodicities found in the astronomical forcing, immediately providing strong support to Milankovitch's theory (Hays et al., 1976).

Ice cores provide key information about past climates, including surface temperatures and atmospheric chemical composition. The bubbles sealed in the ice are the only available samples of these past atmospheres. The first deep ice cores from Vostok in Antarctica (Barnola et al., 1987; Jouzel et al., 1987, 1993) provided additional evidence of the role of astronomical forcing. They also revealed a highly correlated evolution of temperature changes and atmospheric composition, which was subsequently confirmed over the past 400 kyr (Petit et al., 1999) and now extends to almost 1 Myr. This discovery drove research to understand the causal links between greenhouse gases and climate change. The same data that confirmed the astronomical theory also revealed its limits: a linear response of the climate system to astronomical forcing could not explain entirely the observed fluctuations of rapid ice-age terminations preceded by longer cycles of glaciations.

The importance of other sources of climate variability was heightened by the discovery of abrupt climate changes. In this context, 'abrupt' designates regional events of large amplitude, typically a few degrees celsius, which occurred within several decades – much shorter than the thousand-year time scales that characterise changes in astronomical forcing. Abrupt temperature changes were first revealed by the analysis of deep ice cores from Greenland (Dansgaard et al., 1984). Oeschger et al. (1984) recognised that the abrupt changes during the termination of the last ice age correlated with cooling in Gerzensee (Switzerland) and suggested that regime shifts in the Atlantic Ocean circulation were causing these widespread changes. The synthesis of palaeoclimatic observations by Broecker and Denton (1989) invigorated the community over the next decade. By the end of the 1990s, it became clear that the abrupt climate changes during the last ice age, particularly in the North Atlantic regions as found in the Greenland ice cores, were numerous (Dansgaard et al., 1993), indeed abrupt (Alley et al., 1993) and of large amplitude (Severinghaus and Brook, 1999). They are now referred to as Dansgaard-Oeschger events. A similar variability is seen in the North Atlantic Ocean, with north-south oscillations of the polar front (Bond et al., 1992) and associated changes in ocean temperature and salinity (Cortijo et al., 1999). With no obvious external forcing, these changes are thought to be manifestations of the internal variability of the climate system.

The importance of internal variability and processes was reinforced in the early 1990s with analysis of records with high temporal resolution. New ice cores (Greenland Ice Core Project, Johnsen et al., 1992; Greenland Ice Sheet Project 2, Grootes et al., 1993), new ocean cores from regions with high sedimentation rates, as well as lacustrine sediments and cave stalagmites produced additional evidence for unforced climate changes, and revealed a large number of abrupt changes in many regions throughout the last glacial cycle. Long sediment cores from the deep ocean were used to reconstruct the thermohaline circulation connecting deep and surface waters (Bond et al., 1992; Broecker, 1997) and to demonstrate the participation of the ocean in these abrupt climate changes during glacial periods.

By the end of the 1990s, palaeoclimate proxies for a range of climate observations had expanded greatly. The analysis of deep corals provided indicators for nutrient content and mass exchange from the surface to deep water (Adkins et al., 1998), showing abrupt variations characterised by synchronous changes in surface and deep-water properties (Shackleton et al., 2000). Precise measurements of the CH_4 abundances (a global quantity) in polar ice cores showed that they changed in concert with the Dansgaard-Oeschger events and thus allowed for synchronisation of the dating across ice cores (Blunier et al., 1998). The characteristics of the antarctic temperature variations and their relation to the Dansgaard-Oeschger events in Greenland were consistent with the simple concept of a bipolar seesaw caused by changes in the thermohaline circulation of the Atlantic Ocean (Stocker, 1998). This work underlined the role of the ocean in transmitting the signals of abrupt climate change.

Abrupt changes are often regional, for example, severe droughts lasting for many years have changed civilizations, and have occurred during the last 10 kyr of stable warm climate (deMenocal, 2001). This result has altered the notion of a stable climate during warm epochs, as previously suggested by the polar ice cores. The emerging picture of an unstable ocean-atmosphere system has opened the debate of whether human interference through greenhouse gases and aerosols could trigger such events (Broecker, 1997).

Palaeoclimate reconstructions cited in the FAR were based on various data, including pollen records, insect and animal remains, oxygen isotopes and other geological data from lake varves, loess, ocean sediments, ice cores and glacier termini. These records provided estimates of climate variability on time scales up to millions of years. A climate proxy is a local quantitative record (e.g., thickness and chemical properties of tree rings, pollen of different species) that is interpreted as a climate variable (e.g., temperature or rainfall) using a transfer function that is based on physical principles and recently observed correlations between the two records. The combination of instrumental and proxy data began in the 1960s with the investigation of the influence of climate on the proxy data, including tree rings (Fritts, 1962), corals (Weber and Woodhead, 1972; Dunbar and Wellington, 1981) and ice cores (Dansgaard et al., 1984; Jouzel et al., 1987). Phenological and historical data (e.g., blossoming dates, harvest dates, grain prices, ships' logs, newspapers, weather diaries, ancient manuscripts) are also a valuable source of climatic reconstruction for the period before instrumental records became available. Such documentary data also need calibration against instrumental data to extend and reconstruct the instrumental record (Lamb, 1969; Zhu, 1973; van den Dool, 1978; Brazdil, 1992; Pfister, 1992). With the development of multi-proxy reconstructions, the climate data were extended not only from local to global, but also from instrumental data to patterns of climate variability (Wanner et al., 1995; Mann et al., 1998; Luterbacher et al., 1999). Most of these reconstructions were at single sites and only loose efforts had been made to consolidate records. Mann et al. (1998) made a notable advance in the use of proxy data by ensuring that the dating of different records lined up. Thus, the true spatial patterns of temperature variability and change could be derived, and estimates of NH average surface temperatures were obtained.

The Working Group I (WGI) WGI FAR noted that past climates could provide analogues. Fifteen years of research since that assessment has identified a range of variations and instabilities in the climate system that occurred during the last 2 Myr of glacial-interglacial cycles and in the super-warm period of 50 Ma. These past climates do not appear to be analogues of the immediate future, yet they do reveal a wide range of climate processes that need to be understood when projecting 21st-century climate change (see Chapter 6).

1.4.3 Solar Variability and the Total Solar Irradiance

Measurement of the absolute value of total solar irradiance (TSI) is difficult from the Earth's surface because of the need to correct for the influence of the atmosphere. Langley (1884) attempted to minimise the atmospheric effects by taking measurements from high on Mt. Whitney in California, and to estimate the correction for atmospheric effects by taking measurements at several times of day, for example, with the solar radiation having passed through different atmospheric pathlengths. Between 1902 and 1957, Charles Abbot and a number of other scientists around the globe made thousands of measurements of TSI from mountain sites. Values ranged from 1,322 to 1,465 W m^{-2}, which encompasses the current estimate of 1,365 W m^{-2}. Foukal et al. (1977) deduced from Abbot's daily observations that higher values of TSI were associated with more solar faculae (e.g., Abbot, 1910).

In 1978, the Nimbus-7 satellite was launched with a cavity radiometer and provided evidence of variations in TSI (Hickey et al., 1980). Additional observations were made with an active cavity radiometer on the Solar Maximum Mission, launched in 1980 (Willson et al., 1980). Both of these missions showed that the passage of sunspots and faculae across the Sun's disk influenced TSI. At the maximum of the 11-year solar activity cycle, the TSI is larger by about 0.1% than at the minimum. The observation that TSI is highest when sunspots are at their maximum is the opposite of Langley's (1876) hypothesis.

As early as 1910, Abbot believed that he had detected a downward trend in TSI that coincided with a general cooling of climate. The solar cycle variation in irradiance corresponds to an 11-year cycle in radiative forcing which varies by about 0.2 W m^{-2}. There is increasingly reliable evidence of its influence on atmospheric temperatures and circulations, particularly in the higher atmosphere (Reid, 1991; Brasseur, 1993; Balachandran and Rind, 1995; Haigh, 1996; Labitzke and van Loon, 1997; van Loon and Labitzke, 2000). Calculations with three-dimensional models (Wetherald and Manabe, 1975; Cubasch et al., 1997; Lean and Rind, 1998; Tett et al., 1999; Cubasch and Voss, 2000) suggest that the changes in solar radiation could cause surface temperature changes of the order of a few tenths of a degree celsius.

For the time before satellite measurements became available, the solar radiation variations can be inferred from cosmogenic isotopes (^{10}Be, ^{14}C) and from the sunspot number. Naked-eye observations of sunspots date back to ancient times, but it was only after the invention of the telescope in 1607 that it became possible to routinely monitor the number, size and position of these 'stains' on the surface of the Sun. Throughout the 17th and 18th centuries, numerous observers noted the variable concentrations and ephemeral nature of sunspots, but very few sightings were reported between 1672 and 1699 (for an overview see Hoyt et al., 1994). This period of low solar activity, now known as the Maunder Minimum, occurred during the climate period now commonly referred to as the Little Ice Age (Eddy, 1976). There is no exact agreement as to which dates mark the beginning and end of the Little Ice Age, but from about 1350 to about 1850 is one reasonable estimate.

During the latter part of the 18th century, Wilhelm Herschel (1801) noted the presence not only of sunspots but of bright patches, now referred to as faculae, and of granulations on the solar surface. He believed that when these indicators of activity were more numerous, solar emissions of light and heat were greater and could affect the weather on Earth. Heinrich Schwabe (1844) published his discovery of a '10-year cycle' in sunspot numbers. Samuel Langley (1876) compared the brightness of sunspots with that of the surrounding photosphere. He concluded that they would block the emission of radiation and estimated that at sunspot cycle maximum the Sun would be about 0.1% less bright than at the minimum of the cycle, and that the Earth would be 0.1°C to 0.3°C cooler.

These satellite data have been used in combination with the historically recorded sunspot number, records of cosmogenic isotopes, and the characteristics of other Sun-like stars to estimate the solar radiation over the last 1,000 years (Eddy, 1976; Hoyt and Schatten, 1993, 1997; Lean et al., 1995; Lean, 1997). These data sets indicated quasi-periodic changes in solar radiation of 0.24 to 0.30% on the centennial time scale. These values have recently been re-assessed (see, e.g., Chapter 2).

The TAR states that the changes in solar irradiance are not the major cause of the temperature changes in the second half of the 20th century unless those changes can induce unknown large feedbacks in the climate system. The effects of galactic cosmic rays on the atmosphere (via cloud nucleation) and those due to shifts in the solar spectrum towards the ultraviolet (UV) range, at times of high solar activity, are largely unknown. The latter may produce changes in tropospheric circulation via changes in static stability resulting from the interaction of the increased UV radiation with stratospheric ozone. More research to investigate the effects of solar behaviour on climate is needed before the magnitude of solar effects on climate can be stated with certainty.

1.4.4 Biogeochemistry and Radiative Forcing

The modern scientific understanding of the complex and interconnected roles of greenhouse gases and aerosols in climate change has undergone rapid evolution over the last two decades. While the concepts were recognised and outlined in the 1970s (see Sections 1.3.1 and 1.4.1), the publication of generally accepted quantitative results coincides with, and was driven in part by, the questions asked by the IPCC beginning in 1988. Thus, it is instructive to view the evolution of this topic as it has been treated in the successive IPCC reports.

The WGI FAR codified the key physical and biogeochemical processes in the Earth system that relate a changing climate to atmospheric composition, chemistry, the carbon cycle and natural ecosystems. The science of the time, as summarised in the FAR, made a clear case for anthropogenic interference with the climate system. In terms of greenhouse agents, the main conclusions from the WGI FAR Policymakers Summary are still valid today: (1) 'emissions resulting from human activities are substantially increasing the atmospheric concentrations of the greenhouse gases: CO_2, CH_4, CFCs, N_2O'; (2) 'some gases are potentially more effective (at greenhouse warming)'; (3) feedbacks between the carbon cycle, ecosystems and atmospheric greenhouse gases in a warmer world will affect CO_2 abundances; and (4) GWPs provide a metric for comparing the climatic impact of different greenhouse gases, one that integrates both the radiative influence and biogeochemical cycles. The climatic importance of tropospheric ozone, sulphate aerosols and atmospheric chemical feedbacks were proposed by scientists at the time and noted in the assessment. For example, early global chemical modelling results argued that global tropospheric ozone, a greenhouse gas, was controlled by emissions of the highly reactive gases nitrogen oxides (NO_x), carbon monoxide (CO) and non-methane hydrocarbons (NMHC, also known as volatile organic compounds, VOC). In terms of sulphate aerosols, both the direct radiative effects and the indirect effects on clouds were acknowledged, but the importance of carbonaceous aerosols from fossil fuel and biomass combustion was not recognised (Chapters 2, 7 and 10).

The concept of radiative forcing (RF) as the radiative imbalance (W m^{-2}) in the climate system at the top of the atmosphere caused by the addition of a greenhouse gas (or other change) was established at the time and summarised in Chapter 2 of the WGI FAR. Agents of RF included the direct greenhouse gases, solar radiation, aerosols and the Earth's surface albedo. What was new and only briefly mentioned was that 'many gases produce indirect effects on the global radiative forcing'. The innovative global modelling work of Derwent (1990) showed that emissions of the reactive but non-greenhouse gases – NO_x, CO and NMHCs – altered atmospheric chemistry and thus changed the abundance of other greenhouse gases. Indirect GWPs for NO_x, CO and VOCs were proposed. The projected chemical feedbacks were limited to short-lived increases in tropospheric ozone. By 1990, it was clear that the RF from tropospheric ozone had increased over the 20th century and stratospheric ozone had decreased since 1980 (e.g., Lacis et al., 1990), but the associated RFs were not evaluated in the assessments. Neither was the effect of anthropogenic sulphate aerosols, except to note in the FAR that 'it is conceivable that this radiative forcing has been of a comparable magnitude, but of opposite sign, to the greenhouse forcing earlier in the century'. Reflecting in general the community's concerns about this relatively new measure of climate forcing, RF bar charts appear only in the underlying FAR chapters, but not in the FAR Summary. Only the long-lived greenhouse gases are shown, although sulphate aerosols direct effect in the future is noted with a question mark (i.e., dependent on future emissions) (Chapters 2, 7 and 10).

The cases for more complex chemical and aerosol effects were becoming clear, but the scientific community was unable at the time to reach general agreement on the existence, scale and magnitude of these indirect effects. Nevertheless, these early discoveries drove the research agendas in the early 1990s. The widespread development and application of global chemistry-transport models had just begun with international workshops (Pyle et al., 1996; Jacob et al., 1997; Rasch, 2000). In the Supplementary Report (IPCC, 1992) to the FAR, the indirect chemical effects of CO, NO_x and VOC were reaffirmed, and the feedback effect of CH_4 on the tropospheric hydroxyl radical (OH) was noted, but the indirect RF values from the FAR were retracted and denoted in a table with '+', '0' or '–'. Aerosol-climate interactions still focused on sulphates, and the assessment of their direct RF for the NH (i.e., a cooling) was now somewhat quantitative as compared to the FAR. Stratospheric ozone depletion was noted as causing a significant and negative RF, but not quantified. Ecosystems research at this time was identifying the responses to climate change and CO_2 increases, as well as altered CH_4 and N_2O fluxes from natural systems; however, in terms of a community assessment it remained qualitative.

By 1994, with work on SAR progressing, the Special Report on Radiative Forcing (IPCC, 1995) reported significant breakthroughs in a set of chapters limited to assessment of the carbon cycle, atmospheric chemistry, aerosols and RF. The carbon budget for the 1980s was analysed not only from bottom-up emissions estimates, but also from a top-down approach including carbon isotopes. A first carbon cycle assessment was performed through an international model and analysis workshop examining terrestrial and oceanic uptake to better quantify the relationship between CO_2 emissions and the resulting increase in atmospheric abundance. Similarly, expanded analyses of the global budgets of trace gases and aerosols from both natural and anthropogenic sources highlighted the rapid expansion of biogeochemical research. The first RF bar chart appears, comparing all the major components of RF change from the pre-industrial period to the present. Anthropogenic soot aerosol, with a positive RF, was not in the 1995 Special Report but was added to the SAR. In terms of atmospheric chemistry, the first open-invitation modelling study for the IPCC recruited 21 atmospheric chemistry models to participate in a controlled study of photochemistry and chemical feedbacks. These studies (e.g., Olson et al., 1997) demonstrated a robust consensus about some indirect effects, such as the CH_4 impact on atmospheric chemistry, but great uncertainty about others, such as the prediction of tropospheric ozone changes. The model studies plus the theory of chemical feedbacks in the CH_4-CO-OH system (Prather, 1994) firmly established that the atmospheric lifetime of a perturbation (and hence climate impact and GWP) of CH_4 emissions was about 50% greater than reported in the FAR. There was still no consensus on quantifying the past or future changes in tropospheric ozone or OH (the primary sink for CH_4) (Chapters 2, 7 and 10).

In the early 1990s, research on aerosols as climate forcing agents expanded. Based on new research, the range of climate-relevant aerosols was extended for the first time beyond sulphates to include nitrates, organics, soot, mineral dust and sea salt. Quantitative estimates of sulphate aerosol indirect effects on cloud properties and hence RF were sufficiently well established to be included in assessments, and carbonaceous aerosols from biomass burning were recognised as being comparable in importance to sulphate (Penner et al., 1992). Ranges are given in the special report (IPCC, 1995) for direct sulphate RF (–0.25 to –0.9 W m^{-2}) and biomass-burning aerosols (–0.05 to –0.6 W m^{-2}). The aerosol indirect RF was estimated to be about equal to the direct RF, but with larger uncertainty. The injection of stratospheric aerosols from the eruption of Mt. Pinatubo was noted as the first modern test of a known radiative forcing, and indeed one climate model accurately predicted the temperature response (Hansen et al., 1992). In the one-year interval between the special report and the SAR, the scientific understanding of aerosols grew. The direct anthropogenic aerosol forcing (from sulphate, fossil-fuel soot and biomass-burning aerosols) was reduced to –0.5 W m^{-2}. The RF bar chart was now broken into aerosol components (sulphate, fossil-fuel soot and biomass burning aerosols) with a separate range for indirect effects (Chapters 2 and 7; Sections 8.2 and 9.2).

Throughout the 1990s, there were concerted research programs in the USA and EU to evaluate the global environmental impacts of aviation. Several national assessments culminated in the IPCC Special Report on Aviation and the Global Atmosphere (IPCC, 1999), which assessed the impacts on climate and global air quality. An open invitation for atmospheric model participation resulted in community participation and a consensus on many of the environmental impacts of aviation (e.g., the increase in tropospheric ozone and decrease in CH_4 due to NO_x emissions were quantified). The direct RF of sulphate and of soot aerosols was likewise quantified along with that of contrails, but the impact on cirrus clouds that are sometimes generated downwind of contrails was not. The assessment re-affirmed that RF was a first-order metric for the global mean surface temperature response, but noted that it was inadequate for regional climate change, especially in view of the largely regional forcing from aerosols and tropospheric ozone (Sections 2.6, 2.8 and 10.2).

By the end of the 1990s, research on atmospheric composition and climate forcing had made many important advances. The TAR was able to provide a more quantitative evaluation in some areas. For example, a large, open-invitation modelling workshop was held for both aerosols (11 global models) and tropospheric ozone-OH chemistry (14 global models). This workshop brought together as collaborating authors most of the international scientific community involved in developing and testing global models of atmospheric composition. In terms of atmospheric chemistry, a strong consensus was reached for the first time that science could predict the changes in tropospheric ozone in response to scenarios for CH_4 and the indirect greenhouse gases (CO, NO_x, VOC) and that a quantitative GWP for CO could be reported. Further, combining these models with observational analysis, an estimate of the change in tropospheric ozone since the pre-industrial era – with uncertainties – was reported. The aerosol workshop made similar advances in evaluating the impact of different aerosol types. There were many different representations of uncertainty (e.g., a range in models versus an expert judgment) in the TAR, and the consensus RF bar chart did not generate a total RF or uncertainties for use in the subsequent IPCC Synthesis Report (IPCC, 2001b) (Chapters 2 and 7; Section 9.2).

1.4.5 Cryospheric Topics

The cryosphere, which includes the ice sheets of Greenland and Antarctica, continental (including tropical) glaciers, snow, sea ice, river and lake ice, permafrost and seasonally frozen ground, is an important component of the climate system. The cryosphere derives its importance to the climate system from a variety of effects, including its high reflectivity (albedo) for solar radiation, its low thermal conductivity, its large thermal inertia, its potential for affecting ocean circulation (through exchange of freshwater and heat) and atmospheric circulation (through topographic changes), its large potential for affecting sea level (through growth and melt of land ice), and its potential for affecting greenhouse gases (through changes in permafrost) (Chapter 4).

Studies of the cryospheric albedo feedback have a long history. The albedo is the fraction of solar energy reflected back to space. Over snow and ice, the albedo (about 0.7 to 0.9) is large compared to that over the oceans (<0.1). In a warming climate, it is anticipated that the cryosphere would shrink, the Earth's overall albedo would decrease and more solar energy would be absorbed to warm the Earth still further. This powerful feedback loop was recognised in the 19th century by Croll (1890) and was first introduced in climate models by Budyko (1969) and Sellers (1969). But although the principle of the albedo feedback is simple, a quantitative understanding of the effect is still far from complete. For instance, it is not clear whether this mechanism is the main reason for the high-latitude amplification of the warming signal.

The potential cryospheric impact on ocean circulation and sea level are of particular importance. There may be 'large-scale discontinuities' (IPCC, 2001a) resulting from both the shutdown of the large-scale meridional circulation of the world oceans (see Section 1.4.6) and the disintegration of large continental ice sheets. Mercer (1968, 1978) proposed that atmospheric warming could cause the ice shelves of western Antarctica to disintegrate and that as a consequence the entire West Antarctic Ice Sheet (10% of the antarctic ice volume) would lose its land connection and come afloat, causing a sea level rise of about five metres.

The importance of permafrost-climate feedbacks came to be realised widely only in the 1990s, starting with the works of Kvenvolden (1988, 1993), MacDonald (1990) and Harriss et al. (1993). As permafrost thaws due to a warmer climate, CO_2 and CH_4 trapped in permafrost are released to the atmosphere. Since CO_2 and CH_4 are greenhouse gases, atmospheric temperature is likely to increase in turn, resulting in a feedback loop with more permafrost thawing. The permafrost and seasonally thawed soil layers at high latitudes contain a significant amount (about one-quarter) of the global total amount of soil carbon. Because global warming signals are amplified in high-latitude regions, the potential for permafrost thawing and consequent greenhouse gas releases is thus large.

In situ monitoring of the cryosphere has a long tradition. For instance, it is important for fisheries and agriculture. Seagoing communities have documented sea ice extent for centuries. Records of thaw and freeze dates for lake and river ice start with Lake Suwa in Japan in 1444, and extensive records of snowfall in China were made during the Qing Dynasty (1644–1912). Records of glacial length go back to the mid-1500s. Internationally coordinated, long-term glacier observations started in 1894 with the establishment of the International Glacier Commission in Zurich, Switzerland. The longest time series of a glacial mass balance was started in 1946 at the Storglaciären in northern Sweden, followed by Storbreen in Norway (begun in 1949). Today a global network of mass balance monitoring for some 60 glaciers is coordinated through the World Glacier Monitoring Service. Systematic measurements of permafrost (thermal state and active layer) began in earnest around 1950 and were coordinated under the Global Terrestrial Network for Permafrost.

The main climate variables of the cryosphere (extent, albedo, topography and mass) are in principle observable from space, given proper calibration and validation through *in situ* observing efforts. Indeed, satellite data are required in order to have full global coverage. The polar-orbiting Nimbus 5 satellite, launched in 1972, yielded the earliest all-weather, all-season imagery of global sea ice, using microwave instruments (Parkinson et al., 1987), and enabled a major advance in the scientific understanding of the dynamics of the cryosphere. Launched in 1978, the Television Infrared Observation Satellite (TIROS-N) yielded the first monitoring from space of snow on land surfaces (Dozier et al., 1981). The number of cryospheric elements now routinely monitored from space is growing, and current satellites are now addressing one of the more challenging elements, variability of ice volume.

Climate modelling results have pointed to high-latitude regions as areas of particular importance and ecological vulnerability to global climate change. It might seem logical to expect that the cryosphere overall would shrink in a warming climate or expand in a cooling climate. However, potential changes in precipitation, for instance due to an altered hydrological cycle, may counter this effect both regionally and globally. By the time of the TAR, several climate models incorporated physically based treatments of ice dynamics, although the land ice processes were only rudimentary. Improving representation of the cryosphere in climate models is still an area of intense research and continuing progress (Chapter 8).

1.4.6 Ocean and Coupled Ocean-Atmosphere Dynamics

Developments in the understanding of the oceanic and atmospheric circulations, as well as their interactions, constitute a striking example of the continuous interplay among theory, observations and, more recently, model simulations. The atmosphere and ocean surface circulations were observed and analysed globally as early as the 16th and 17th centuries, in close association with the development of worldwide trade based on sailing. These efforts led to a number of important conceptual and theoretical works. For example, Edmund Halley first published a description of the tropical atmospheric cells in 1686, and George Hadley proposed a theory linking the existence of the trade winds with those cells in 1735. These early studies helped to forge concepts that are still useful in analysing and understanding both the atmospheric general circulation itself and model simulations (Lorenz, 1967; Holton, 1992).

A comprehensive description of these circulations was delayed by the lack of necessary observations in the higher atmosphere or deeper ocean. The balloon record of Gay-Lussac, who reached an altitude of 7,016 m in 1804, remained unbroken for more than 50 years. The stratosphere was independently discovered near the turn of the 20th century by Aßmann (1902) and Teisserenc de Bort (1902), and the first manned balloon flight into the stratosphere was made in 1901 (Berson and Süring, 1901). Even though it was recognised over 200 years ago (Rumford, 1800; see also Warren, 1981) that the oceans' cold subsurface waters must originate at high latitudes, it was not appreciated until the 20th century that the strength of the deep circulation might vary over time, or that the ocean's Meridional Overturning Circulation (MOC; often loosely referred to as the 'thermohaline circulation', see the Glossary for more information) may be very important for Earth's climate.

By the 1950s, studies of deep-sea cores suggested that the deep ocean temperatures had varied in the distant past. Technology also evolved to enable measurements that could confirm that the deep ocean is not only not static, but in fact quite dynamic (Swallow and Stommel's 1960 subsurface float experiment Aries, referred to by Crease, 1962). By the late 1970s, current meters could monitor deep currents for substantial amounts of time, and the first ocean observing satellite (SeaSat) revealed that significant information about subsurface ocean variability is imprinted on the sea surface. At the same time, the first estimates of the strength of the meridional transport of heat and mass were made (Oort and Vonder Haar, 1976; Wunsch, 1978), using a combination of models and data. Since then the technological developments have accelerated, but monitoring the MOC directly remains a substantial challenge (see Chapter 5), and routine observations of the subsurface ocean remain scarce compared to that of the atmosphere.

In parallel with the technological developments yielding new insights through observations, theoretical and numerical explorations of multiple (stable or unstable) equilibria began. Chamberlain (1906) suggested that deep ocean currents could reverse in direction, and might affect climate. The idea did not gain momentum until fifty years later, when Stommel (1961) presented a mechanism, based on the opposing effects that temperature and salinity have on density, by which ocean circulation can fluctuate between states. Numerical climate models incorporating models of the ocean circulation were developed during this period, including the pioneering work of Bryan (1969) and Manabe and Bryan (1969). The idea that the ocean circulation could change radically, and might perhaps even feel the attraction of different equilibrium states, gained further support through the simulations of coupled climate models (Bryan and Spelman, 1985; Bryan, 1986; Manabe and Stouffer, 1988). Model simulations using a hierarchy of models showed that the ocean circulation system appeared to be particularly vulnerable to changes in the freshwater balance, either by direct addition of freshwater or by changes in the hydrological cycle. A strong case emerged for the hypothesis that rapid changes in the Atlantic meridional circulation were responsible for the abrupt Dansgaard-Oeschger climate change events.

Although scientists now better appreciate the strength and variability of the global-scale ocean circulation, its roles in climate are still hotly debated. Is it a passive recipient of atmospheric forcing and so merely a diagnostic consequence of climate change, or is it an active contributor? Observational evidence for the latter proposition was presented by Sutton and Allen (1997), who noticed SST anomalies propagating along the Gulf Stream/North Atlantic Current system for years, and therefore implicated internal oceanic time scales. Is a radical change in the MOC likely in the near future? Brewer et al. (1983) and Lazier (1995) showed that the water masses of the North Atlantic were indeed changing (some becoming significantly fresher) in the modern observational record, a phenomenon that at least raises the possibility that ocean conditions may be approaching the point where the circulation might shift into Stommel's other stable regime. Recent developments in the ocean's various roles in climate can be found in Chapters 5, 6, 9 and 10.

Studying the interactions between atmosphere and ocean circulations was also facilitated through continuous interactions between observations, theories and simulations, as is dramatically illustrated by the century-long history of the advances in understanding the El Niño-Southern Oscillation (ENSO) phenomenon. This coupled air-sea phenomenon originates in the Pacific but affects climate globally, and has raised concern since at least the 19th century. Sir Gilbert Walker (1928) describes how H. H. Hildebrandsson (1897) noted large-scale relationships between interannual trends in pressure data from a worldwide network of 68 weather stations, and how Lockyer and Lockyer (1902) confirmed Hildebrandsson's discovery of an apparent 'seesaw' in pressure between South America and the Indonesian region. Walker named this seesaw pattern the 'Southern Oscillation' and related it to occurrences of drought and heavy rains in India, Australia, Indonesia and Africa. He also proposed that there must be a certain level of predictive skill in that system.

El Niño is the name given to the rather unusual oceanic conditions involving anomalously warm waters occurring in the eastern tropical Pacific off the coast of Peru every few years. The 1957–1958 International Geophysical Year coincided with a large El Niño, allowing a remarkable set of observations of the phenomenon. A decade later, a mechanism was presented that connected Walker's observations to El Niño (Bjerknes, 1969). This mechanism involved the interaction, through the SST field, between the east-west atmospheric circulation of which Walker's Southern Oscillation was an indicator (Bjerknes appropriately referred to this as the 'Walker Circulation') and variability in the pool of equatorial warm water of the Pacific Ocean. Observations made in the 1970s (e.g., Wyrtki, 1975) showed that prior to ENSO warm phases, the sea level in the western Pacific often rises significantly. By the mid-1980s, after an unusually disruptive El Niño struck in 1982 and 1983, an observing system (the Tropical Ocean Global Atmosphere (TOGA) array; see McPhaden et al., 1998) had been put in place to monitor ENSO. The resulting data confirmed the idea that the phenomenon was inherently one involving coupled atmosphere-ocean interactions and yielded much-needed detailed observational insights. By 1986, the first experimental ENSO forecasts were made (Cane et al., 1986; Zebiak and Cane, 1987).

The mechanisms and predictive skill of ENSO are still under discussion. In particular, it is not clear how ENSO changes with, and perhaps interacts with, a changing climate. The TAR states '...increasing evidence suggests the ENSO plays a fundamental role in global climate and its interannual variability, and increased credibility in both regional and global climate projections will be gained once realistic ENSOs and their changes are simulated'.

Just as the phenomenon of El Niño has been familiar to the people of tropical South America for centuries, a spatial pattern affecting climate variability in the North Atlantic has similarly been known by the people of Northern Europe for a long time. The Danish missionary Hans Egede made the following well-known diary entry in the mid-18th century: 'In Greenland, all winters are severe, yet they are not alike. The Danes have noticed that when the winter in Denmark was severe, as we perceive it, the winter in Greenland in its manner was mild, and conversely' (van Loon and Rogers, 1978).

Teisserenc de Bort, Hann, Exner, Defant and Walker all contributed to the discovery of the underlying dynamic structure. Walker, in his studies in the Indian Ocean, actually studied global maps of sea level pressure correlations, and named not only the Southern Oscillation, but also a Northern Oscillation, which he subsequently divided into a North Pacific and a North Atlantic Oscillation (Walker, 1924). However, it was Exner (1913, 1924) who made the first correlation maps showing the spatial structure in the NH, where the North Atlantic Oscillation (NAO) pattern stands out clearly as a north-south oscillation in atmospheric mass with centres of action near Iceland and Portugal.

The NAO significantly affects weather and climate, ecosystems and human activities of the North Atlantic sector. But what is the underlying mechanism? The recognition that the NAO is associated with variability and latitudinal shifts in the westerly flow of the jet stream originates with the works of Willett, Namias, Lorenz, Rossby and others in the 1930s, 1940s and 1950s (reviewed by Stephenson et al., 2003). Because atmospheric planetary waves are hemispheric in nature, changes in one region are often connected with changes in other regions, a phenomenon dubbed 'teleconnection' (Wallace and Gutzler, 1981).

The NAO may be partly described as a high-frequency stochastic process internal to the atmosphere. This understanding is evidenced by numerous atmosphere-only model simulations. It is also considered an expression of one of Earth's 'annular modes' (See Chapter 3). It is, however, the low-frequency variability of this phenomenon (Hurrell, 1995) that fuels continued investigations by climate scientists. The long time scales are the indication of potential predictive skill in the NAO. The mechanisms responsible for the correspondingly long 'memory' are still debated, although they are likely to have a local or remote oceanic origin. Bjerknes (1964) recognised the connection between the NAO index (which he referred to as the 'zonal index') and sea surface conditions. He speculated that ocean heat advection could play a role on longer time scales. The circulation of the Atlantic Ocean is radically different from that of the Indian and Pacific Oceans, in that the MOC is strongest in the Atlantic with warm water flowing northwards, even south of the equator, and cold water returning at depth. It would therefore not be surprising if the oceanic contributions to the NAO and to the Southern Oscillation were different.

Earth's climate is characterised by many modes of variability, involving both the atmosphere and ocean, and also the cryosphere and biosphere. Understanding the physical processes involved in producing low-frequency variability is crucial for improving scientists' ability to accurately predict climate change and for allowing the separation of anthropogenic and natural variability, thereby improving the ability to detect and attribute anthropogenic climate change. One central question for climate scientists, addressed in particular in Chapter 9, is to determine how human activities influence the dynamic nature of Earth's climate, and to identify what would have happened without any human influence at all.

1.5 Examples of Progress in Modelling the Climate

1.5.1 Model Evolution and Model Hierarchies

Climate scenarios rely upon the use of numerical models. The continuous evolution of these models over recent decades has been enabled by a considerable increase in computational capacity, with supercomputer speeds increasing by roughly a factor of a million in the three decades from the 1970s to the present. This computational progress has permitted a corresponding increase in model complexity (by including more and more components and processes, as depicted in Figure 1.2), in the length of the simulations, and in spatial resolution, as shown in Figure 1.4. The models used to evaluate future climate changes have therefore evolved over time. Most of the pioneering work on CO_2-induced climate change was based on atmospheric general circulation models coupled to simple 'slab' ocean models (i.e., models omitting ocean dynamics), from the early work of Manabe and Wetherald (1975) to the review of Schlesinger and Mitchell (1987). At the same time the physical content of the models has become more comprehensive (see in Section 1.5.2 the example of clouds). Similarly, most of the results presented in the FAR were from atmospheric models, rather than from models of the coupled climate system, and were used to analyse changes in the equilibrium climate resulting from a doubling of the atmospheric CO_2 concentration. Current climate projections can investigate time-dependent scenarios of climate evolution and can make use of much more complex coupled ocean-atmosphere models, sometimes even including interactive chemical or biochemical components.

A parallel evolution toward increased complexity and resolution has occurred in the domain of numerical weather prediction, and has resulted in a large and verifiable improvement in operational weather forecast quality. This example alone shows that present models are more realistic than were those of a decade ago. There is also, however, a continuing awareness that models do not provide a perfect simulation of reality, because resolving all important spatial or time scales remains far beyond current capabilities, and also because the behaviour of such a complex nonlinear system may in general be chaotic.

It has been known since the work of Lorenz (1963) that even simple models may display intricate behaviour because of their nonlinearities. The inherent nonlinear behaviour of the climate system appears in climate simulations at all time scales (Ghil, 1989). In fact, the study of nonlinear dynamical systems has become important for a wide range of scientific disciplines, and the corresponding mathematical developments are essential to interdisciplinary studies. Simple models of ocean-atmosphere interactions, climate-biosphere interactions or climate-economy interactions may exhibit a similar behaviour, characterised by partial unpredictability, bifurcations and transition to chaos.

In addition, many of the key processes that control climate sensitivity or abrupt climate changes (e.g., clouds, vegetation, oceanic convection) depend on very small spatial scales. They cannot be represented in full detail in the context of global models, and scientific understanding of them is still notably incomplete. Consequently, there is a continuing need to assist in the use and interpretation of complex models through models that are either conceptually simpler, or limited to a number of processes or to a specific region, therefore enabling a deeper understanding of the processes at work or a more relevant comparison with observations. With the development of computer capacities, simpler models have not disappeared; on the contrary, a stronger emphasis has been given to the concept of a 'hierarchy of models' as the only way to provide a linkage between theoretical understanding and the complexity of realistic models (Held, 2005).

The list of these 'simpler' models is very long. Simplicity may lie in the reduced number of equations (e.g., a single

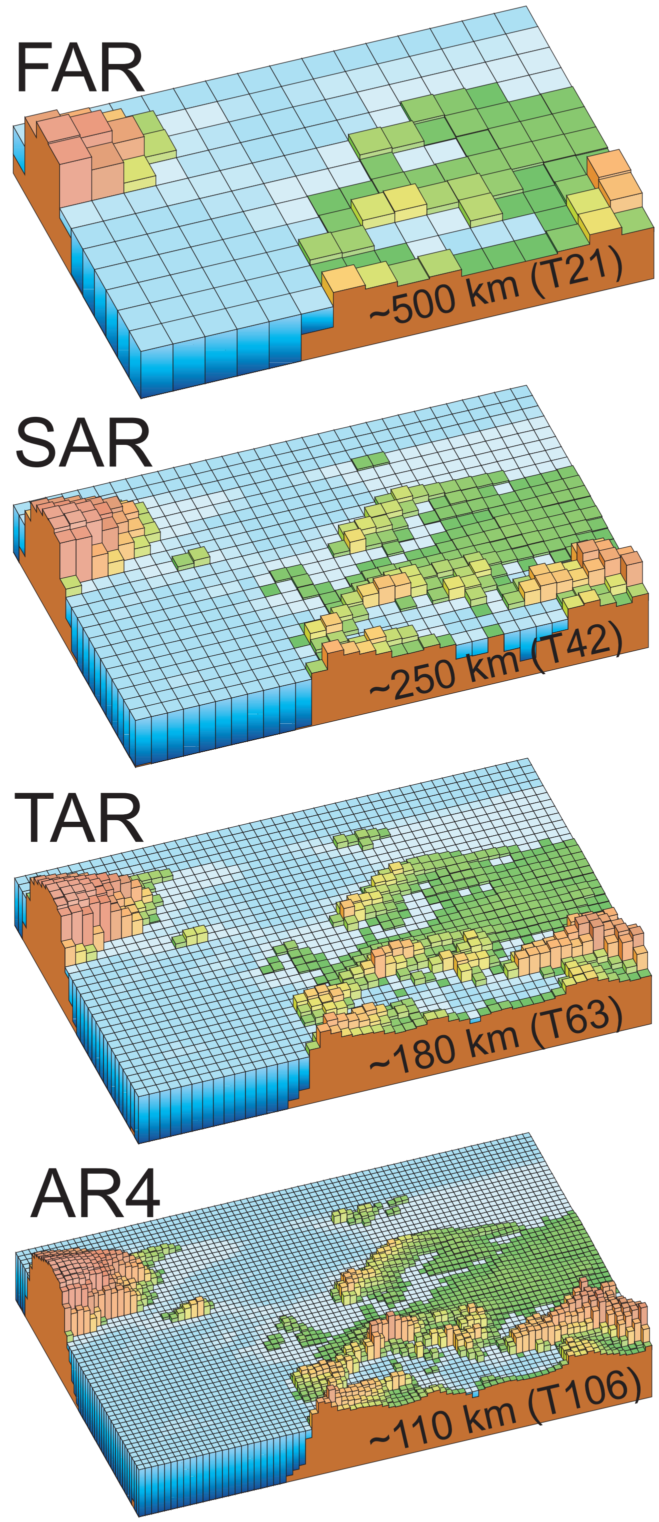


Figure 1.4. *Geographic resolution characteristic of the generations of climate models used in the IPCC Assessment Reports: FAR (IPCC, 1990), SAR (IPCC, 1996), TAR (IPCC, 2001a), and AR4 (2007). The figures above show how successive generations of these global models increasingly resolved northern Europe. These illustrations are representative of the most detailed horizontal resolution used for short-term climate simulations. The century-long simulations cited in IPCC Assessment Reports after the FAR were typically run with the previous generation's resolution. Vertical resolution in both atmosphere and ocean models is not shown, but it has increased comparably with the horizontal resolution, beginning typically with a single-layer slab ocean and ten atmospheric layers in the FAR and progressing to about thirty levels in both atmosphere and ocean.*

equation for the global surface temperature); in the reduced dimensionality of the problem (one-dimension vertical, one-dimension latitudinal, two-dimension); or in the restriction to a few processes (e.g., a mid-latitude quasi-geostrophic atmosphere with or without the inclusion of moist processes). The notion of model hierarchy is also linked to the idea of scale: global circulation models are complemented by regional models that exhibit a higher resolution over a given area, or process oriented models, such as cloud resolving models or large eddy simulations. Earth Models of Intermediate Complexity are used to investigate long time scales, such as those corresponding to glacial to interglacial oscillations (Berger et al., 1998). This distinction between models according to scale is evolving quickly, driven by the increase in computer capacities. For example, global models explicitly resolving the dynamics of convective clouds may soon become computationally feasible.

Many important scientific debates in recent years have had their origin in the use of conceptually simple models. The study of idealised atmospheric representations of the tropical climate, for example by Pierrehumbert (1995) who introduced a separate representation of the areas with ascending and subsiding circulation in the tropics, has significantly improved the understanding of the feedbacks that control climate. Simple linearized models of the atmospheric circulation have been used to investigate potential new feedback effects. Ocean box models have played an important role in improving the understanding of the possible slowing down of the Atlantic thermohaline circulation (Birchfield et al., 1990), as emphasized in the TAR. Simple models have also played a central role in the interpretation of IPCC scenarios: the investigation of climate scenarios presented in the SAR or the TAR has been extended to larger ensembles of cases using idealised models.

1.5.2 Model Clouds and Climate Sensitivity

The modelling of cloud processes and feedbacks provides a striking example of the irregular pace of progress in climate science. Representation of clouds may constitute the area in which atmospheric models have been modified most continuously to take into account increasingly complex physical processes. At the time of the TAR clouds remained a major source of uncertainty in the simulation of climate changes (as they still are at present: e.g., Sections 2.4, 2.6, 3.4.3, 7.5, 8.2, 8.4.11, 8.6.2.2, 8.6.3.2, 9.2.1.2, 9.4.1.8, 10.2.1.2, 10.3.2.2, 10.5.4.3, 11.8.1.3, 11.8.2.2).

In the early 1980s, most models were still using prescribed cloud amounts, as functions of location and altitude, and prescribed cloud radiative properties, to compute atmospheric radiation. The cloud amounts were very often derived from the zonally averaged climatology of London (1957). Succeeding generations of models have used relative humidity or other simple predictors to diagnose cloudiness (Slingo, 1987), thus providing a foundation of increased realism for the models, but at the same time possibly causing inconsistencies in the representation of the multiple roles of clouds as bodies interacting with radiation, generating precipitation and influencing small-scale convective or turbulent circulations. Following the pioneering studies of Sundqvist (1978), an explicit representation of clouds was progressively introduced into climate models, beginning in the late 1980s. Models first used simplified representations of cloud microphysics, following, for example, Kessler (1969), but more recent generations of models generally incorporate a much more comprehensive and detailed representation of clouds, based on consistent physical principles. Comparisons of model results with observational data presented in the TAR have shown that, based on zonal averages, the representation of clouds in most climate models was also more realistic in 2000 than had been the case only a few years before.

In spite of this undeniable progress, the amplitude and even the sign of cloud feedbacks was noted in the TAR as highly uncertain, and this uncertainty was cited as one of the key factors explaining the spread in model simulations of future climate for a given emission scenario. This cannot be regarded as a surprise: that the sensitivity of the Earth's climate to changing atmospheric greenhouse gas concentrations must depend strongly on cloud feedbacks can be illustrated on the simplest theoretical grounds, using data that have been available for a long time. Satellite measurements have indeed provided meaningful estimates of Earth's radiation budget since the early 1970s (Vonder Haar and Suomi, 1971). Clouds, which cover about 60% of the Earth's surface, are responsible for up to two-thirds of the planetary albedo, which is about 30%. An albedo decrease of only 1%, bringing the Earth's albedo from 30% to 29%, would cause an increase in the black-body radiative equilibrium temperature of about 1°C, a highly significant value, roughly equivalent to the direct radiative effect of a doubling of the atmospheric CO_2 concentration. Simultaneously, clouds make an important contribution to the planetary greenhouse effect. In addition, changes in cloud cover constitute only one of the many parameters that affect cloud radiative interactions: cloud optical thickness, cloud height and cloud microphysical properties can also be modified by atmospheric temperature changes, which adds to the complexity of feedbacks, as evidenced, for example, through satellite observations analysed by Tselioudis and Rossow (1994).

The importance of simulated cloud feedbacks was revealed by the analysis of model results (Manabe and Wetherald, 1975; Hansen et al, 1984), and the first extensive model intercomparisons (Cess et al., 1989) also showed a substantial model dependency. The strong effect of cloud processes on climate model sensitivities to greenhouse gases was emphasized further through a now-classic set of General Circulation Model (GCM) experiments, carried out by Senior and Mitchell (1993). They produced global average surface temperature changes (due to doubled atmospheric CO_2 concentration) ranging from 1.9°C to 5.4°C, simply by altering the way that cloud radiative properties were treated in the model. It is somewhat unsettling that the results of a complex climate model can be so drastically altered by substituting one reasonable cloud parametrization for another, thereby approximately replicating the overall inter-model range of sensitivities. Other GCM groups have also

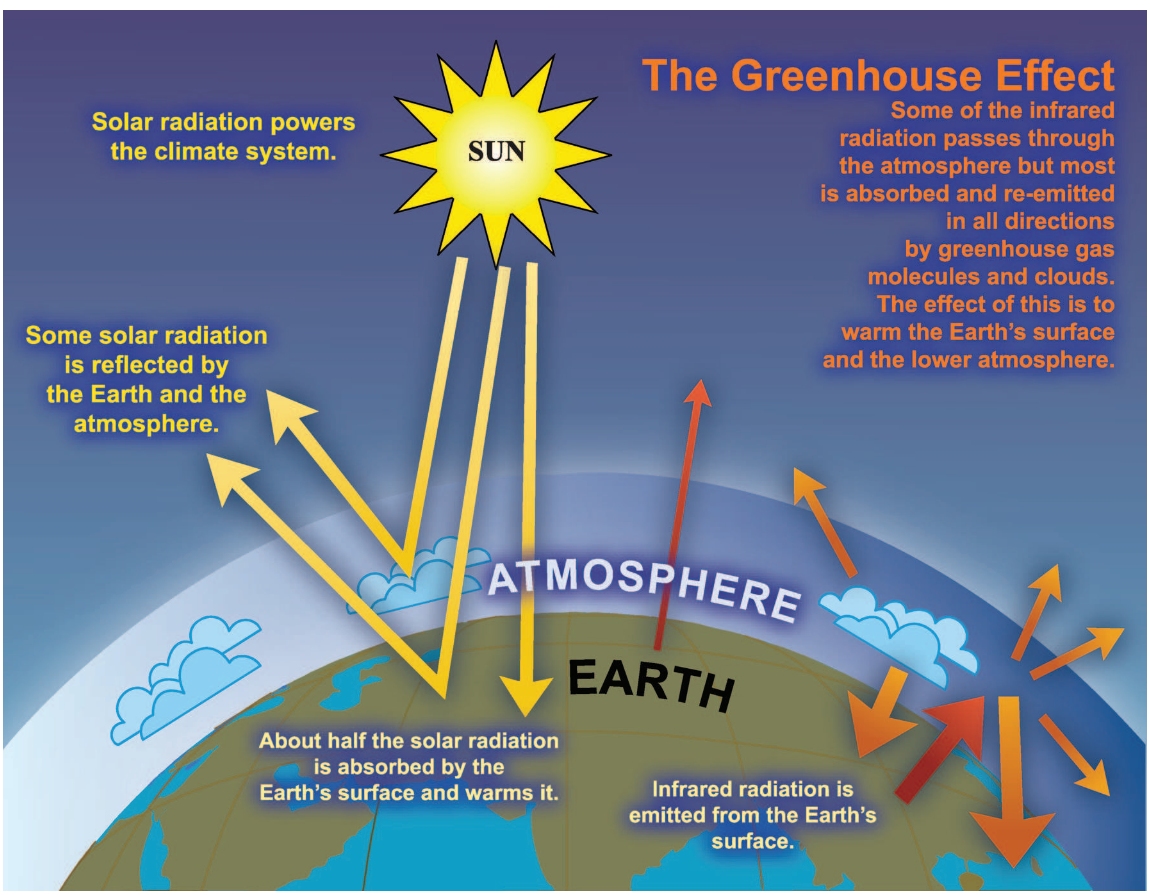
Frequently Asked Question 1.3

What is the Greenhouse Effect?

The Sun powers Earth's climate, radiating energy at very short wavelengths, predominately in the visible or near-visible (e.g., ultraviolet) part of the spectrum. Roughly one-third of the solar energy that reaches the top of Earth's atmosphere is reflected directly back to space. The remaining two-thirds is absorbed by the surface and, to a lesser extent, by the atmosphere. To balance the absorbed incoming energy, the Earth must, on average, radiate the same amount of energy back to space. Because the Earth is much colder than the Sun, it radiates at much longer wavelengths, primarily in the infrared part of the spectrum (see Figure 1). Much of this thermal radiation emitted by the land and ocean is absorbed by the atmosphere, including clouds, and reradiated back to Earth. This is called the greenhouse effect. The glass walls in a greenhouse reduce airflow and increase the temperature of the air inside. Analogously, but through a different physical process, the Earth's greenhouse effect warms the surface of the planet. Without the natural greenhouse effect, the average temperature at Earth's surface would be below the freezing point of water. Thus, Earth's natural greenhouse effect makes life as we know it possible. However, human activities, primarily the burning of fossil fuels and clearing of forests, have greatly intensified the natural greenhouse effect, causing global warming.

The two most abundant gases in the atmosphere, nitrogen (comprising 78% of the dry atmosphere) and oxygen (comprising 21%), exert almost no greenhouse effect. Instead, the greenhouse effect comes from molecules that are more complex and much less common. Water vapour is the most important greenhouse gas, and carbon dioxide (CO_2) is the second-most important one. Methane, nitrous oxide, ozone and several other gases present in the atmosphere in small amounts also contribute to the greenhouse effect. In the humid equatorial regions, where there is so much water vapour in the air that the greenhouse effect is very large, adding a small additional amount of CO_2 or water vapour has only a small direct impact on downward infrared radiation. However, in the cold, dry polar regions, the effect of a small increase in CO_2 or

(continued)



FAQ 1.3, Figure 1. *An idealised model of the natural greenhouse effect. See text for explanation.*

water vapour is much greater. The same is true for the cold, dry upper atmosphere where a small increase in water vapour has a greater influence on the greenhouse effect than the same change in water vapour would have near the surface.

Several components of the climate system, notably the oceans and living things, affect atmospheric concentrations of greenhouse gases. A prime example of this is plants taking CO_2 out of the atmosphere and converting it (and water) into carbohydrates via photosynthesis. In the industrial era, human activities have added greenhouse gases to the atmosphere, primarily through the burning of fossil fuels and clearing of forests.

Adding more of a greenhouse gas, such as CO_2, to the atmosphere intensifies the greenhouse effect, thus warming Earth's climate. The amount of warming depends on various feedback mechanisms. For example, as the atmosphere warms due to rising levels of greenhouse gases, its concentration of water vapour increases, further intensifying the greenhouse effect. This in turn causes more warming, which causes an additional increase in water vapour, in a self-reinforcing cycle. This water vapour feedback may be strong enough to approximately double the increase in the greenhouse effect due to the added CO_2 alone.

Additional important feedback mechanisms involve clouds. Clouds are effective at absorbing infrared radiation and therefore exert a large greenhouse effect, thus warming the Earth. Clouds are also effective at reflecting away incoming solar radiation, thus cooling the Earth. A change in almost any aspect of clouds, such as their type, location, water content, cloud altitude, particle size and shape, or lifetimes, affects the degree to which clouds warm or cool the Earth. Some changes amplify warming while others diminish it. Much research is in progress to better understand how clouds change in response to climate warming, and how these changes affect climate through various feedback mechanisms.

consistently obtained widely varying results by trying other techniques of incorporating cloud microphysical processes and their radiative interactions (e.g., Roeckner et al., 1987; Le Treut and Li, 1991), which differed from the approach of Senior and Mitchell (1993) through the treatment of partial cloudiness or mixed-phase properties. The model intercomparisons presented in the TAR showed no clear resolution of this unsatisfactory situation.

The scientific community realised long ago that using adequate data to constrain models was the only way to solve this problem. Using climate changes in the distant past to constrain the amplitude of cloud feedback has definite limitations (Ramstein et al., 1998). The study of cloud changes at decadal, interannual or seasonal time scales therefore remains a necessary path to constrain models. A long history of cloud observations now runs parallel to that of model development. Operational ground-based measurements, carried out for the purpose of weather prediction, constitute a valuable source of information that has been gathered and analysed by Warren et al. (1986, 1988). The International Satellite Cloud Climatology Project (ISCCP; Rossow and Schiffer, 1991) has developed an analysis of cloud cover and cloud properties using the measurements of operational meteorological satellites over a period of more than two decades. These data have been complemented by other satellite remote sensing data sets, such as those associated with the Nimbus-7 Temperature Humidity Infrared Radiometer (THIR) instrument (Stowe et al., 1988), with high-resolution spectrometers such as the High Resolution Infrared Radiation Sounder (HIRS) (Susskind et al., 1987), and with microwave absorption, as used by the Special Sensor Microwave/Imager (SSM/I). Chapter 8 provides an update of this ongoing observational effort.

A parallel effort has been carried out to develop a wider range of ground-based measurements, not only to provide an adequate reference for satellite observations, but also to make possible a detailed and empirically based analysis of the entire range of space and time scales involved in cloud processes. The longest-lasting and most comprehensive effort has been the Atmospheric Radiation Measurement (ARM) Program in the USA, which has established elaborately instrumented observational sites to monitor the full complexity of cloud systems on a long-term basis (Ackerman and Stokes, 2003). Shorter field campaigns dedicated to the observation of specific phenomena have also been established, such as the TOGA Coupled Ocean-Atmosphere Response Experiment (COARE) for convective systems (Webster and Lukas, 1992), or the Atlantic Stratocumulus Transition Experiment (ASTEX) for stratocumulus (Albrecht et al., 1995).

Observational data have clearly helped the development of models. The ISCCP data have greatly aided the development of cloud representations in climate models since the mid-1980s (e.g., Le Treut and Li, 1988; Del Genio et al., 1996). However, existing data have not yet brought about any reduction in the existing range of simulated cloud feedbacks. More recently, new theoretical tools have been developed to aid in validating parametrizations in a mode that emphasizes the role of cloud processes participating in climatic feedbacks. One such approach has been to focus on comprehensively observed episodes of cloudiness for which the large-scale forcing is observationally known, using single-column models (Randall et al., 1996; Somerville, 2000) and higher-resolution cloud-resolving models to evaluate GCM parametrizations. Another approach is to make use of the more global and continuous satellite data, on a statistical basis, through an investigation of the correlation between climate forcing and cloud parameters (Bony et al., 1997), in such a way as to provide a test of feedbacks between different climate variables. Chapter 8 assesses recent progress in this area.

1.5.3 Coupled Models: Evolution, Use, Assessment

The first National Academy of Sciences of the USA report on global warming (Charney et al., 1979), on the basis of two models simulating the impact of doubled atmospheric CO_2 concentrations, spoke of a range of global mean equilibrium surface temperature increase of between 1.5°C and 4.5°C, a range that has remained part of conventional wisdom at least as recently as the TAR. These climate projections, as well as those treated later in the comparison of three models by Schlesinger and Mitchell (1987) and most of those presented in the FAR, were the results of atmospheric models coupled with simple 'slab' ocean models (i.e., models omitting all changes in ocean dynamics).

The first attempts at coupling atmospheric and oceanic models were carried out during the late 1960s and early 1970s (Manabe and Bryan, 1969; Bryan et al., 1975; Manabe et al., 1975). Replacing 'slab' ocean models by fully coupled ocean-atmosphere models may arguably have constituted one of the most significant leaps forward in climate modelling during the last 20 years (Trenberth, 1993), although both the atmospheric and oceanic components themselves have undergone highly significant improvements. This advance has led to significant modifications in the patterns of simulated climate change, particularly in oceanic regions. It has also opened up the possibility of exploring transient climate scenarios, and it constitutes a step toward the development of comprehensive 'Earth-system models' that include explicit representations of chemical and biogeochemical cycles.

Throughout their short history, coupled models have faced difficulties that have considerably impeded their development, including: (i) the initial state of the ocean is not precisely known; (ii) a surface flux imbalance (in either energy, momentum or fresh water) much smaller than the observational accuracy is enough to cause a drifting of coupled GCM simulations into unrealistic states; and (iii) there is no direct stabilising feedback that can compensate for any errors in the simulated salinity. The strong emphasis placed on the realism of the simulated base state provided a rationale for introducing 'flux adjustments' or 'flux corrections' (Manabe and Stouffer, 1988; Sausen et al., 1988) in early simulations. These were essentially empirical corrections that could not be justified on physical principles, and that consisted of arbitrary additions of surface fluxes of heat and salinity in order to prevent the drift of the simulated climate away from a realistic state. The National Center for Atmospheric Research model may have been the first to realise non-flux-corrected coupled simulations systematically, and it was able to achieve simulations of climate change into the 21st century, in spite of a persistent drift that still affected many of its early simulations. Both the FAR and the SAR pointed out the apparent need for flux adjustments as a problematic feature of climate modelling (Cubasch et al., 1990; Gates et al., 1996).

By the time of the TAR, however, the situation had evolved, and about half the coupled GCMs assessed in the TAR did not employ flux adjustments. That report noted that 'some non-flux-adjusted models are now able to maintain stable climatologies of comparable quality to flux-adjusted models' (McAvaney et al., 2001). Since that time, evolution away from flux correction (or flux adjustment) has continued at some modelling centres, although a number of state-of-the-art models continue to rely on it. The design of the coupled model simulations is also strongly linked with the methods chosen for model initialisation. In flux-adjusted models, the initial ocean state is necessarily the result of preliminary and typically thousand-year-long simulations to bring the ocean model into equilibrium. Non-flux-adjusted models often employ a simpler procedure based on ocean observations, such as those compiled by Levitus et al. (1994), although some spin-up phase is even then necessary. One argument brought forward is that non-adjusted models made use of *ad hoc* tuning of radiative parameters (i.e., an implicit flux adjustment).

This considerable advance in model design has not diminished the existence of a range of model results. This is not a surprise, however, because it is known that climate predictions are intrinsically affected by uncertainty (Lorenz, 1963). Two distinct kinds of prediction problems were defined by Lorenz (1975). The first kind was defined as the prediction of the actual properties of the climate system in response to a given initial state. Predictions of the first kind are initial-value problems and, because of the nonlinearity and instability of the governing equations, such systems are not predictable indefinitely into the future. Predictions of the second kind deal with the determination of the response of the climate system to changes in the external forcings. These predictions are not concerned directly with the chronological evolution of the climate state, but rather with the long-term average of the statistical properties of climate. Originally, it was thought that predictions of the second kind do not at all depend on initial conditions. Instead, they are intended to determine how the statistical properties of the climate system (e.g., the average annual global mean temperature, or the expected number of winter storms or hurricanes, or the average monsoon rainfall) change as some external forcing parameter, for example CO_2 content, is altered. Estimates of future climate scenarios as a function of the concentration of atmospheric greenhouse gases are typical examples of predictions of the second kind. However, ensemble simulations show that the projections tend to form clusters around a number of attractors as a function of their initial state (see Chapter 10).

Uncertainties in climate predictions (of the second kind) arise mainly from model uncertainties and errors. To assess and disentangle these effects, the scientific community has organised a series of systematic comparisons of the different existing models, and it has worked to achieve an increase in the number and range of simulations being carried out in order to more fully explore the factors affecting the accuracy of the simulations.

An early example of systematic comparison of models is provided by Cess et al. (1989), who compared results of documented differences among model simulations in their representation of cloud feedback to show how the consequent effects on atmospheric radiation resulted in different model response to doubling of the CO_2 concentration. A number of ambitious and comprehensive 'model intercomparison projects' (MIPs) were set up in the 1990s under the auspices of the World Climate Research Programme to undertake controlled conditions for model evaluation. One of the first was the Atmospheric Model Intercomparison Project (AMIP), which studied atmospheric GCMs. The development of coupled models induced the development of the Coupled Model Intercomparison Project (CMIP), which studied coupled ocean-atmosphere GCMs and their response to idealised forcings, such as a 1% yearly increase in the atmospheric CO_2 concentration. It proved important in carrying out the various MIPs to standardise the model forcing parameters and the model output so that file formats, variable names, units, etc., are easily recognised by data users. The fact that the model results were stored separately and independently of the modelling centres, and that the analysis of the model output was performed mainly by research groups independent of the modellers, has added confidence in the results. Summary diagnostic products such as the Taylor (2001) diagram were developed for MIPs.

The establishment of the AMIP and CMIP projects opened a new era for climate modelling, setting standards of quality control, providing organisational continuity and ensuring that results are generally reproducible. Results from AMIP have provided a number of insights into climate model behaviour (Gates et al., 1999) and quantified improved agreement between simulated and observed atmospheric properties as new versions of models are developed. In general, results of the MIPs suggest that the most problematic areas of coupled model simulations involve cloud-radiation processes, the cryosphere, the deep ocean and ocean-atmosphere interactions.

Comparing different models is not sufficient, however. Using multiple simulations from a single model (the so-called Monte Carlo, or ensemble, approach) has proved a necessary and complementary approach to assess the stochastic nature of the climate system. The first ensemble climate change simulations with global GCMs used a set of different initial and boundary conditions (Cubasch et al., 1994; Barnett, 1995). Computational constraints limited early ensembles to a relatively small number of samples (fewer than 10). These ensemble simulations clearly indicated that even with a single model a large spread in the climate projections can be obtained.

Intercomparison of existing models and ensemble model studies (i.e., those involving many integrations of the same model) are still undergoing rapid development. Running ensembles was essentially impossible until recent advances in computer power occurred, as these systematic comprehensive climate model studies are exceptionally demanding on computer resources. Their progress has marked the evolution from the FAR to the TAR, and is likely to continue in the years to come.

1.6 The IPCC Assessments of Climate Change and Uncertainties

The WMO and the United Nations Environment Programme (UNEP) established the IPCC in 1988 with the assigned role of assessing the scientific, technical and socioeconomic information relevant for understanding the risk of human-induced climate change. The original 1988 mandate for the IPCC was extensive: '(a) Identification of uncertainties and gaps in our present knowledge with regard to climate changes and its potential impacts, and preparation of a plan of action over the short-term in filling these gaps; (b) Identification of information needed to evaluate policy implications of climate change and response strategies; (c) Review of current and planned national/international policies related to the greenhouse gas issue; (d) Scientific and environmental assessments of all aspects of the greenhouse gas issue and the transfer of these assessments and other relevant information to governments and intergovernmental organisations to be taken into account in their policies on social and economic development and environmental programs.' The IPCC is open to all members of UNEP and WMO. It does not directly support new research or monitor climate-related data. However, the IPCC process of synthesis and assessment has often inspired scientific research leading to new findings.

The IPCC has three Working Groups and a Task Force. Working Group I (WGI) assesses the scientific aspects of the climate system and climate change, while Working Groups II (WGII) and III (WGIII) assess the vulnerability and adaptation of socioeconomic and natural systems to climate change, and the mitigation options for limiting greenhouse gas emissions, respectively. The Task Force is responsible for the IPCC National Greenhouse Gas Inventories Programme. This brief history focuses on WGI and how it has described uncertainty in the quantities presented (See Box 1.1).

A main activity of the IPCC is to provide on a regular basis an assessment of the state of knowledge on climate change, and this volume is the fourth such Assessment Report of WGI. The IPCC also prepares Special Reports and Technical Papers on topics for which independent scientific information and advice is deemed necessary, and it supports the United Nations Framework Convention on Climate Change (UNFCCC) through its work on methodologies for National Greenhouse Gas Inventories. The FAR played an important role in the discussions of the Intergovernmental Negotiating Committee for the UNFCCC. The UNFCCC was adopted in 1992 and entered into force in 1994. It provides the overall policy framework and legal basis for addressing the climate change issue.

The WGI FAR was completed under the leadership of Bert Bolin (IPCC Chair) and John Houghton (WGI Chair) in a plenary at Windsor, UK in May 1990. In a mere 365 pages with eight colour plates, it made a persuasive, but not quantitative, case for anthropogenic interference with the climate system. Most conclusions from the FAR were non-quantitative and remain valid today (see also Section 1.4.4). For example, in terms of the greenhouse gases, 'emissions resulting from human activities are substantially increasing the atmospheric concentrations of the greenhouse gases: CO_2, CH_4, CFCs, N_2O' (see Chapters 2 and 3; Section 7.1). On the other hand, the FAR did not foresee the phase-out of CFCs, missed the importance of biomass-burning aerosols and dust to climate and stated that unequivocal detection of the enhanced greenhouse effect was more than a decade away. The latter two areas highlight the advance of climate science and in particular the merging of models and observations in the new field of detection and attribution (see Section 9.1).

The Policymakers Summary of the WGI FAR gave a broad overview of climate change science and its Executive Summary separated key findings into areas of varying levels of confidence ranging from 'certainty' to providing an expert 'judgment'. Much of the summary is not quantitative (e.g., the radiative forcing bar charts do not appear in the summary). Similarly, scientific uncertainty is hardly mentioned; when ranges are given, as in the projected temperature increases of 0.2°C to 0.5°C per decade, no probability or likelihood is assigned to explain the range (see Chapter 10). In discussion of the climate sensitivity to doubled atmospheric CO_2 concentration, the combined subjective and objective criteria are explained: the range of model results was 1.9°C to 5.2°C; most were close to 4.0°C; but the newer model results were lower; and hence the best estimate was 2.5°C with a range of 1.5°C to 4.5°C. The likelihood of the value being within this range was not defined. However, the importance of identifying those areas where climate scientists had high confidence was recognised in the Policymakers Summary.

The Supplementary Report (IPCC, 1992) re-evaluated the RF values of the FAR and included the new IPCC scenarios for future emissions, designated IS92a–f. It also included updated chapters on climate observations and modelling (see Chapters 3, 4, 5, 6 and 8). The treatment of scientific uncertainty remained as in the FAR. For example, the calculated increase in global mean surface temperature since the 19th century was given as 0.45°C ± 0.15°C, with no quantitative likelihood for this range (see Section 3.2).

The SAR, under Bert Bolin (IPCC Chair) and John Houghton and Gylvan Meira Filho (WGI Co-chairs), was planned with and coupled to a preliminary Special Report (IPCC, 1995) that contained intensive chapters on the carbon cycle, atmospheric chemistry, aerosols and radiative forcing. The WGI SAR culminated in the government plenary in Madrid in November 1995. The most cited finding from that plenary, on attribution of climate change, has been consistently reaffirmed by subsequent research: 'The balance of evidence suggests a discernible human influence on global climate' (see Chapter 9). The SAR provided key input to the negotiations that led to the adoption in 1997 of the Kyoto Protocol to the UNFCCC.

Uncertainty in the WGI SAR was defined in a number of ways. The carbon cycle budgets used symmetric plus/minus ranges explicitly defined as 90% confidence intervals, whereas the RF bar chart reported a 'mid-range' bar along with a plus/minus range that was estimated largely on the spread of published values. The likelihood, or confidence interval, of the spread of published results was not given. These uncertainties were additionally modified by a declaration that the confidence of the RF being within the specified range was indicated by a stated confidence level that ranged from 'high' (greenhouse gases) to 'very low' (aerosols). Due to the difficulty in approving such a long draft in plenary, the Summary for Policy Makers (SPM) became a short document with no figures and few numbers. The use of scientific uncertainty in the SPM was thus limited and similar to the FAR: a range in the mean surface temperature increase since 1900 was given as 0.3°C to 0.6°C with no explanation as to likelihood of this range. While the underlying report showed projected future warming for a range of different climate models, the Technical Summary focused on a central estimate.

The IPCC Special Report on Aviation and the Global Atmosphere (IPCC, 1999) was a major interim assessment involving both WGI and WGIII and the Scientific Assessment Panel to the Montreal Protocol on Substances that Deplete the Ozone Layer. It assessed the impacts of civil aviation in terms of climate change and global air quality as well as looking at the effect of technology options for the future fleet. It was the first complete assessment of an industrial sub-sector. The summary related aviation's role relative to all human influence on the climate system: 'The best estimate of the radiative forcing in 1992 by aircraft is 0.05 W m^{-2} or about 3.5% of the total radiative forcing by all anthropogenic activities.' The authors took a uniform approach to assigning and propagating uncertainty in these RF values based on mixed objective and subjective criteria. In addition to a best value, a two-thirds likelihood (67% confidence) interval is given. This interval is similar to a one-sigma (i.e., one standard deviation) normal error distribution, but it was explicitly noted that the probability distribution outside this interval was not evaluated and might not have a normal distribution. A bar chart with 'whiskers' (two-thirds likelihood range) showing the components and total (without cirrus effects) RF for aviation in 1992 appeared in the SPM (see Sections 2.6 and 10.2).

The TAR, under Robert Watson (IPCC Chair) and John Houghton and Ding YiHui (WGI Co-chairs), was approved at the government plenary in Shanghai in January 2001. The predominant summary statements from the TAR WGI strengthened the SAR's attribution statement: 'An increasing body of observations gives a collective picture of a warming world and other changes in the climate system', and 'There is new and stronger evidence that most of the warming observed over the last 50 years is attributable to human activities.' The TAR Synthesis Report (IPCC, 2001b) combined the assessment reports from the three Working Groups. By combining data on global (WGI) and regional (WGII) climate change, the Synthesis Report was able to strengthen the conclusion regarding human influence: 'The Earth's climate system has demonstrably changed on both global and regional scales since the pre-industrial era, with some of these changes attributable to human activities' (see Chapter 9).

Box 1.1: Treatment of Uncertainties in the Working Group I Assessment

The importance of consistent and transparent treatment of uncertainties is clearly recognised by the IPCC in preparing its assessments of climate change. The increasing attention given to formal treatments of uncertainty in previous assessments is addressed in Section 1.6. To promote consistency in the general treatment of uncertainty across all three Working Groups, authors of the Fourth Assessment Report have been asked to follow a brief set of guidance notes on determining and describing uncertainties in the context of an assessment .[1] This box summarises the way that Working Group I has applied those guidelines and covers some aspects of the treatment of uncertainty specific to material assessed here.

Uncertainties can be classified in several different ways according to their origin. Two primary types are 'value uncertainties' and 'structural uncertainties'. Value uncertainties arise from the incomplete determination of particular values or results, for example, when data are inaccurate or not fully representative of the phenomenon of interest. Structural uncertainties arise from an incomplete understanding of the processes that control particular values or results, for example, when the conceptual framework or model used for analysis does not include all the relevant processes or relationships. Value uncertainties are generally estimated using statistical techniques and expressed probabilistically. Structural uncertainties are generally described by giving the authors' collective judgment of their confidence in the correctness of a result. In both cases, estimating uncertainties is intrinsically about describing the limits to knowledge and for this reason involves expert judgment about the state of that knowledge. A different type of uncertainty arises in systems that are either chaotic or not fully deterministic in nature and this also limits our ability to project all aspects of climate change.

The scientific literature assessed here uses a variety of other generic ways of categorising uncertainties. Uncertainties associated with 'random errors' have the characteristic of decreasing as additional measurements are accumulated, whereas those associated with 'systematic errors' do not. In dealing with climate records, considerable attention has been given to the identification of systematic errors or unintended biases arising from data sampling issues and methods of analysing and combining data. Specialised statistical methods based on quantitative analysis have been developed for the detection and attribution of climate change and for producing probabilistic projections of future climate parameters. These are summarised in the relevant chapters.

The uncertainty guidance provided for the Fourth Assessment Report draws, for the first time, a careful distinction between levels of confidence in scientific understanding and the likelihoods of specific results. This allows authors to express high confidence that an event is extremely unlikely (e.g., rolling a dice twice and getting a six both times), as well as high confidence that an event is about as likely as not (e.g., a tossed coin coming up heads). Confidence and likelihood as used here are distinct concepts but are often linked in practice.

The standard terms used to define levels of confidence in this report are as given in the IPCC Uncertainty Guidance Note, namely:

Confidence Terminology	Degree of confidence in being correct
Very high confidence	At least 9 out of 10 chance
High confidence	About 8 out of 10 chance
Medium confidence	About 5 out of 10 chance
Low confidence	About 2 out of 10 chance
Very low confidence	Less than 1 out of 10 chance

Note that 'low confidence' and 'very low confidence' are only used for areas of major concern and where a risk-based perspective is justified.

Chapter 2 of this report uses a related term 'level of scientific understanding' when describing uncertainties in different contributions to radiative forcing. This terminology is used for consistency with the Third Assessment Report, and the basis on which the authors have determined particular levels of scientific understanding uses a combination of approaches consistent with the uncertainty guidance note as explained in detail in Section 2.9.2 and Table 2.11.

[1] See Supplementary Material for this report

The standard terms used in this report to define the likelihood of an outcome or result where this can be estimated probabilistically are:

Likelihood Terminology	**Likelihood of the occurrence/ outcome**
Virtually certain	> 99% probability
Extremely likely	> 95% probability
Very likely	> 90% probability
Likely	> 66% probability
More likely than not	> 50% probability
About as likely as not	33 to 66% probability
Unlikely	< 33% probability
Very unlikely	< 10% probability
Extremely unlikely	< 5% probability
Exceptionally unlikely	< 1% probability

The terms 'extremely likely', 'extremely unlikely' and 'more likely than not' as defined above have been added to those given in the IPCC Uncertainty Guidance Note in order to provide a more specific assessment of aspects including attribution and radiative forcing.

Unless noted otherwise, values given in this report are assessed best estimates and their uncertainty ranges are 90% confidence intervals (i.e., there is an estimated 5% likelihood of the value being below the lower end of the range or above the upper end of the range). Note that in some cases the nature of the constraints on a value, or other information available, may indicate an asymmetric distribution of the uncertainty range around a best estimate.

In an effort to promote consistency, a guidance paper on uncertainty (Moss and Schneider, 2000) was distributed to all Working Group authors during the drafting of the TAR. The WGI TAR made some effort at consistency, noting in the SPM that when ranges were given they generally denoted 95% confidence intervals, although the carbon budget uncertainties were specified as ±1 standard deviation (68% likelihood). The range of 1.5°C to 4.5°C for climate sensitivity to atmospheric CO_2 doubling was reiterated but with no confidence assigned; however, it was clear that the level of scientific understanding had increased since that same range was first given in the Charney et al. (1979) report. The RF bar chart noted that the RF components could not be summed (except for the long-lived greenhouse gases) and that the 'whiskers' on the RF bars each meant something different (e.g., some were the range of models, some were uncertainties). Another failure in dealing with uncertainty was the projection of 21st-century warming: it was reported as a range covering (i) six Special Report on Emission Scenarios (SRES) emissions scenarios and (ii) nine atmosphere-ocean climate models using two grey envelopes without estimates of likelihood levels. The full range (i.e., scenario plus climate model range) of 1.4°C to 5.8°C is a much-cited finding of the WGI TAR but the lack of discussion of associated likelihood in the report makes the interpretation and useful application of this result difficult.

1.7 Summary

As this chapter shows, the history of the centuries-long effort to document and understand climate change is often complex, marked by successes and failures, and has followed a very uneven pace. Testing scientific findings and openly discussing the test results have been the key to the remarkable progress that is now accelerating in all domains, in spite of inherent limitations to predictive capacity. Climate change science is now contributing to the foundation of a new interdisciplinary approach to understanding our environment. Consequently, much published research and many notable scientific advances have occurred since the TAR, including advances in the understanding and treatment of uncertainty. Key aspects of recent climate change research are assessed in Chapters 2 through 11 of this report.

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Chapter I

[EPA–HQ–OAR–2009–0171; FRL–9091–8]

RIN 2060–ZA14

Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Administrator finds that six greenhouse gases taken in combination endanger both the public health and the public welfare of current and future generations. The Administrator also finds that the combined emissions of these greenhouse gases from new motor vehicles and new motor vehicle engines contribute to the greenhouse gas air pollution that endangers public health and welfare under CAA section 202(a). These Findings are based on careful consideration of the full weight of scientific evidence and a thorough review of numerous public comments received on the Proposed Findings published April 24, 2009.

DATES: These Findings are effective on January 14, 2010.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2009–0171. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Jeremy Martinich, Climate Change Division, Office of Atmospheric Programs (MC–6207J), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; telephone number: (202) 343–9927; fax number: (202) 343–2202; e-mail address: *ghgendangerment@epa.gov*. For additional information regarding these Findings, please go to the Web site *http://www.epa.gov/climatechange/endangerment.html*.

SUPPLEMENTARY INFORMATION:

Judicial Review

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by February 16, 2010. Under CAA section 307(d)(7)(B), only an objection to this final action that was raised with reasonable specificity during the period for public comment can be raised during judicial review. This section also provides a mechanism for us to convene a proceeding for reconsideration, " '[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of this rule.' " Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20004.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

ACUS Administrative Conference of the United States
ANPR Advance Notice of Proposed Rulemaking
APA Administrative Procedure Act
CAA Clean Air Act
CAFE Corporate Average Fuel Economy
CAIT Climate Analysis Indicators Tool
CASAC Clean Air Scientific Advisory Committee
CBI Confidential Business Information
CCSP Climate Change Science Program
CFCs chlorofluorocarbons
CFR Code of Federal Regulations
CH_4 methane
CO_2 carbon dioxide
CO_2e CO_2-equivalent
CRU Climate Research Unit
DOT U.S. Department of Transportation
EO Executive Order
EPA U.S. Environmental Protection Agency
FR **Federal Register**
GHG greenhouse gas
GWP global warming potential
HadCRUT Hadley Centre/Climate Research Unit (CRU) temperature record
HCFCs hydrochlorofluorocarbons
HFCs hydrofluorocarbons
IA Interim Assessment report
IPCC Intergovernmental Panel on Climate Change
MPG miles per gallon
MWP Medieval Warm Period
N_2O nitrous oxide
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NASA National Aeronautics and Space Administration
NF_3 nitrogen trifluoride
NHTSA National Highway Traffic Safety Administration
NOAA National Oceanic and Atmospheric Administration
NOI Notice of Intent
NO_X nitrogen oxides
NRC National Research Council
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act of 1995
OMB Office of Management and Budget
PFCs perfluorocarbons
PM particulate matter
PSD Prevention of Significant Deterioration
RFA Regulatory Flexibility Act
SF_6 sulfur hexafluoride
SIP State Implementation Plan
TSD technical support document
U.S. United States
UMRA Unfunded Mandates Reform Act of 1995
UNFCCC United Nations Framework Convention on Climate Change
USGCRP U.S. Global Climate Research Program
VOC volatile organic compound(s)
WCI Western Climate Initiative
WRI World Resources Institute

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I. Introduction

A. Overview

Pursuant to CAA section 202(a), the Administrator finds that greenhouse gases in the atmosphere may reasonably be anticipated both to endanger public health and to endanger public welfare. Specifically, the Administrator is defining the ''air pollution'' referred to in CAA section 202(a) to be the mix of six long-lived and directly-emitted greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). In this document, these six greenhouse gases are referred to as ''well-mixed greenhouse gases'' in this document (with more precise meanings of ''long lived'' and ''well mixed'' provided in Section IV.A).

The Administrator has determined that the body of scientific evidence compellingly supports this finding. The major assessments by the U.S. Global Climate Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) serve as the primary scientific basis supporting the Administrator's endangerment finding.[1] The Administrator reached her determination by considering both observed and projected effects of greenhouse gases in the atmosphere, their effect on climate, and the public health and welfare risks and impacts associated with such climate change. The Administrator's assessment focused on public health and public welfare impacts within the United States. She also examined the evidence with respect to impacts in other world regions, and she concluded that these impacts strengthen the case for endangerment to public health and welfare because impacts in other world regions can in turn adversely affect the United States.

The Administrator recognizes that human-induced climate change has the potential to be far-reaching and multi-dimensional, and in light of existing knowledge, that not all risks and potential impacts can be quantified or characterized with uniform metrics. There is variety not only in the nature and potential magnitude of risks and impacts, but also in our ability to characterize, quantify and project such impacts into the future. The Administrator is using her judgment, based on existing science, to weigh the threat for each of the identifiable risks, to weigh the potential benefits where relevant, and ultimately to assess whether these risks and effects, when viewed in total, endanger public health or welfare.

The Administrator has considered how elevated concentrations of the well-mixed greenhouse gases and associated climate change affect public health by evaluating the risks associated with changes in air quality, increases in temperatures, changes in extreme weather events, increases in food- and water-borne pathogens, and changes in aeroallergens. The evidence concerning adverse air quality impacts provides strong and clear support for an endangerment finding. Increases in ambient ozone are expected to occur over broad areas of the country, and they are expected to increase serious adverse health effects in large population areas that are and may continue to be in nonattainment. The evaluation of the potential risks associated with increases in ozone in attainment areas also supports such a finding.

The impact on mortality and morbidity associated with increases in average temperatures, which increase the likelihood of heat waves, also provides support for a public health endangerment finding. There are uncertainties over the net health impacts of a temperature increase due to decreases in cold-related mortality, but some recent evidence suggests that the net impact on mortality is more likely to be adverse, in a context where heat is already the leading cause of weather-related deaths in the United States.

The evidence concerning how human-induced climate change may alter extreme weather events also clearly supports a finding of endangerment, given the serious adverse impacts that can result from such events and the increase in risk, even if small, of the occurrence and intensity of events such as hurricanes and floods. Additionally, public health is expected to be

[1] Section III of these Findings discusses the science on which these Findings are based. In addition, the Technical Support Document (TSD) accompanying these Findings summarizes the major assessments from the USGCRP, IPCC, and NRC.

adversely affected by an increase in the severity of coastal storm events due to rising sea levels.

There is some evidence that elevated carbon dioxide concentrations and climate changes can lead to changes in aeroallergens that could increase the potential for allergenic illnesses. The evidence on pathogen borne disease vectors provides directional support for an endangerment finding. The Administrator acknowledges the many uncertainties in these areas. Although these adverse effects provide some support for an endangerment finding, the Administrator is not placing primary weight on these factors.

Finally, the Administrator places weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to these climate-related health effects.

The Administrator has considered how elevated concentrations of the well-mixed greenhouse gases and associated climate change affect public welfare by evaluating numerous and far-ranging risks to food production and agriculture, forestry, water resources, sea level rise and coastal areas, energy, infrastructure, and settlements, and ecosystems and wildlife. For each of these sectors, the evidence provides support for a finding of endangerment to public welfare. The evidence concerning adverse impacts in the areas of water resources and sea level rise and coastal areas provides the clearest and strongest support for an endangerment finding, both for current and future generations. Strong support is also found in the evidence concerning infrastructure and settlements, as well ecosystems and wildlife. Across the sectors, the potential serious adverse impacts of extreme events, such as wildfires, flooding, drought, and extreme weather conditions, provide strong support for such a finding.

Water resources across large areas of the country are at serious risk from climate change, with effects on water supplies, water quality, and adverse effects from extreme events such as floods and droughts. Even areas of the country where an increase in water flow is projected could face water resource problems from the supply and water quality problems associated with temperature increases and precipitation variability, as well as the increased risk of serious adverse effects from extreme events, such as floods and drought. The severity of risks and impacts is likely to increase over time with accumulating greenhouse gas concentrations and associated temperature increases and precipitation changes.

Overall, the evidence on risk of adverse impacts for coastal areas provides clear support for a finding that greenhouse gas air pollution endangers the welfare of current and future generations. The most serious potential adverse effects are the increased risk of storm surge and flooding in coastal areas from sea level rise and more intense storms. Observed sea level rise is already increasing the risk of storm surge and flooding in some coastal areas. The conclusion in the assessment literature that there is the potential for hurricanes to become more intense (and even some evidence that Atlantic hurricanes have already become more intense) reinforces the judgment that coastal communities are now endangered by human-induced climate change, and may face substantially greater risk in the future. Even if there is a low probability of raising the destructive power of hurricanes, this threat is enough to support a finding that coastal communities are endangered by greenhouse gas air pollution. In addition, coastal areas face other adverse impacts from sea level rise such as land loss due to inundation, erosion, wetland submergence, and habitat loss. The increased risk associated with these adverse impacts also endangers public welfare, with an increasing risk of greater adverse impacts in the future.

Strong support for an endangerment finding is also found in the evidence concerning energy, infrastructure, and settlements, as well ecosystems and wildlife. While the impacts on net energy demand may be viewed as generally neutral for purposes of making an endangerment determination, climate change is expected to result in an increase in electricity production, especially supply for peak demand. This may be exacerbated by the potential for adverse impacts from climate change on hydropower resources as well as the potential risk of serious adverse effects on energy infrastructure from extreme events. Changes in extreme weather events threaten energy, transportation, and water resource infrastructure. Vulnerabilities of industry, infrastructure, and settlements to climate change are generally greater in high-risk locations, particularly coastal and riverine areas, and areas whose economies are closely linked with climate-sensitive resources. Climate change will likely interact with and possibly exacerbate ongoing environmental change and environmental pressures in settlements, particularly in Alaska where indigenous communities are facing major environmental and cultural impacts on their historic lifestyles. Over the 21st century, changes in climate will cause some species to shift north and to higher elevations and fundamentally rearrange U.S. ecosystems. Differential capacities for range shifts and constraints from development, habitat fragmentation, invasive species, and broken ecological connections will likely alter ecosystem structure, function, and services, leading to predominantly negative consequences for biodiversity and the provision of ecosystem goods and services.

There is a potential for a net benefit in the near term [2] for certain crops, but there is significant uncertainty about whether this benefit will be achieved given the various potential adverse impacts of climate change on crop yield, such as the increasing risk of extreme weather events. Other aspects of this sector may be adversely affected by climate change, including livestock management and irrigation requirements, and there is a risk of adverse effect on a large segment of the total crop market. For the near term, the concern over the potential for adverse effects in certain parts of the agriculture sector appears generally comparable to the potential for benefits for certain crops. However, The body of evidence points towards increasing risk of net adverse impacts on U.S. food production and agriculture over time, with the potential for significant disruptions and crop failure in the future.

For the near term, the Administrator finds the beneficial impact on forest growth and productivity in certain parts of the country from elevated carbon dioxide concentrations and temperature increases to date is offset by the clear risk from the observed increases in wildfires, combined with risks from the spread of destructive pests and disease. For the longer term, the risk from adverse effects increases over time, such that overall climate change presents serious adverse risks for forest productivity. There is compelling reason to find that the support for a positive endangerment finding increases as one considers expected future conditions where temperatures continue to rise.

Looking across all of the sectors discussed above, the evidence provides compelling support for finding that greenhouse gas air pollution endangers the public welfare of both current and

[2] The temporal scope of impacts is discussed in more detail in Section III.C. The phrase ''near term'' as used in this document generally refers to the current time period from and the next few decades. The phrase ''long term'' generally refers to a time frame extending beyond that to approximately the middle to the end of this century.

future generations. The risk and the severity of adverse impacts on public welfare are expected to increase over time.

The Administrator also finds that emissions of well-mixed greenhouse gases from the transportation sources covered under CAA section 202(a) [3] contribute to the total greenhouse gas air pollution, and thus to the climate change problem, which is reasonably anticipated to endanger public health and welfare. The Administrator is defining the air pollutant that contributes to climate change as the aggregate group of the well-mixed greenhouse gases. The definition of air pollutant used by the Administrator is based on the similar attributes of these substances. These attributes include the fact that they are sufficiently long-lived to be well mixed globally in the atmosphere, that they are directly emitted, and that they exert a climate warming effect by trapping outgoing, infrared heat that would otherwise escape to space, and that they are the focus of climate change science and policy.

In order to determine if emissions of the well-mixed greenhouse gases from CAA section 202(a) source categories contribute to the air pollution that endangers public health and welfare, the Administrator compared the emissions from these CAA section 202(a) source categories to total global and total U.S. greenhouse gas emissions, finding that these source categories are responsible for about 4 percent of total global well-mixed greenhouse gas emissions and just over 23 percent of total U.S. well-mixed greenhouse gas emissions. The Administrator found that these comparisons, independently and together, clearly establish that these emissions contribute to greenhouse gas concentrations. For example, the emissions of well-mixed greenhouse gases from CAA section 202(a) sources are larger in magnitude than the total well-mixed greenhouse gas emissions from every other individual nation with the exception of China, Russia, and India, and are the second largest emitter within the United States behind the electricity generating sector. As the Supreme Court noted, ''[j]udged by any standard, U.S. motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming.'' *Massachusetts* v. *EPA,* 549 U.S. 497, 525 (2007).

[3] Section 202(a) source categories include passenger cars, heavy-, medium and light-duty trucks, motorcycles, and buses.

The Administrator's findings are in response to the Supreme Court's decision in *Massachusetts* v. *EPA.* That case involved a 1999 petition submitted by the International Center for Technology Assessment and 18 other environmental and renewable energy industry organizations requesting that EPA issue standards under CAA section 202(a) for the emissions of carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons from new motor vehicles and engines. The Administrator's findings are in response to this petition and are for purposes of CAA section 202(a).

B. Background Information Helpful To Understand These Findings

This section provides some basic information regarding greenhouse gases and the CAA section 202(a) source categories, as well as the ongoing joint-rulemaking on greenhouse gases by EPA and the Department of Transportation. Additional technical and legal background, including a summary of the Supreme Court's *Massachusetts* v. *EPA* decision, can be found in the Proposed Endangerment and Contribution Findings (74 FR 18886, April 24, 2009).

1. Greenhouse Gases and Transportation Sources Under CAA Section 202(a)

Greenhouse gases are naturally present in the atmosphere and are also emitted by human activities. Greenhouse gases trap the Earth's heat that would otherwise escape from the atmosphere, and thus form the greenhouse effect that helps keep the Earth warm enough for life. Human activities are intensifying the naturally-occurring greenhouse effect by adding greenhouse gases to the atmosphere. The primary greenhouse gases of concern that are directly emitted by human activities include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. Other pollutants (such as aerosols) and other human activities, such as land use changes that alter the reflectivity of the Earth's surface, also cause climatic warming and cooling effects. In these Findings, the term ''climate change'' generally refers to the global warming effect plus other associated changes (*e.g.,* precipitation effects, sea level rise, changes in the frequency and severity of extreme weather events) being induced by human activities, including activities that emit greenhouse gases. Natural causes also, contribute to climate change and climatic changes have occurred throughout the Earth's history. The concern now, however, is that the changes taking place in our atmosphere as a result of the well-documented buildup of greenhouse gases due to human activities are changing the climate at a pace and in a way that threatens human health, society, and the natural environment. Further detail on the state of climate change science can be found in Section III of these Findings as well as the technical support document (TSD) that accompanies this action (*www.epa.gov/climatechange/endangerment.html*).

The transportation sector is a major source of greenhouse gas emissions both in the United States and in the rest of the world. The transportation sources covered under CAA section 202(a)—the section of the CAA under which these Findings occur—include passenger cars, light- and heavy-duty trucks, buses, and motorcycles. These transportation sources emit four key greenhouse gases: carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons. Together, these transportation sources are responsible for 23 percent of total annual U.S. greenhouse gas emissions, making this source the second largest in the United States behind electricity generation.[4]

Further discussion of the emissions data supporting the Administrator's cause or contribute finding can be found in Section V of these Findings, and the detailed greenhouse gas emissions data for section 202(a) source categories can be found in Appendix B of EPA's TSD.

2. Joint EPA and Department of Transportation Proposed Greenhouse Gas Rule

On September 15, 2009, EPA and the Department of Transportation's National Highway Safety Administration (NHTSA) proposed a National Program that would dramatically reduce greenhouse gas emissions and improve fuel economy for new cars and trucks sold in the United States. The combined EPA and NHTSA standards that make up this proposed National Program would apply to passenger cars, light-duty trucks, and medium-duty passenger vehicles, covering model years 2012 through 2016. They proposed to require these vehicles to meet an estimated combined average

[4] The units for greenhouse gas emissions in these findings are provided in carbon dioxide equivalent units, where carbon dioxide is the reference gas and every other greenhouse gas is converted to its carbon dioxide equivalent by using the 100-year global warming potential (as estimated by the Intergovernmental Panel on Climate Change (IPCC). assigned to each gas. The reference gas used is CO_2, and therefore Global Warming Potential (GWP)-weighted emissions are measured in teragrams of CO_2 equivalent (Tg CO_2 eq.). In accordance with UNFCCC reporting procedures, the United States quantifies greenhouse gas emissions using the 100-year time frame values for GWPs established in the IPCC Second Assessment Report.

emissions level of 250 grams of carbon dioxide per mile, equivalent to 35.5 miles per gallon (MPG) if the automobile industry were to meet this carbon dioxide level solely through fuel economy improvements. Together, these proposed standards would cut carbon dioxide emissions by an estimated 950 million metric tons and 1.8 billion barrels of oil over the lifetime of the vehicles sold under the program (model years 2012–2016). The proposed rulemaking can be viewed at (74 FR 49454, September 28, 2009).

C. Public Involvement

In response to the Supreme Court's decision, EPA has been examining the scientific and technical basis for the endangerment and cause or contribute decisions under CAA section 202(a) since 2007. The science informing the decision-making process has grown stronger since our work began. EPA's approach to evaluating the science, including comments submitted during the public comment period, is further discussed in Section III.A of these Findings. Public review and comment has always been a major component of EPA's process.

1. EPA's Initial Work on Endangerment

As part of the *Advance Notice of Proposed Rulemaking: Regulating Greenhouse Gas Emissions under the Clean Air Act* (73 FR 44353) published in July 2008, EPA provided a thorough discussion of the issues and options pertaining to endangerment and cause or contribute findings under the CAA. The Agency also issued a TSD providing an overview of all the major scientific assessments available at the time and emission inventory data relevant to the contribution finding (Docket ID No. EPA–HQ–OAR–2008–0318). The comment period for that *Advance Notice* was 120 days, and it provided an opportunity for EPA to hear from the public with regard to the issues involved in endangerment and cause or contribute findings as well as the supporting science. EPA received, reviewed and considered numerous comments at that time and this public input was reflected in the Findings that the Administrator proposed in April 2009. In addition, many comments were received on the TSD released with the *Advance Notice* and reflected in revisions to the TSD released in April 2009 to accompany the Administrator's proposal. All public comments on the *Advance Notice* are contained in the public docket for this action (Docket ID No. EPA–HQ–OAR–2008–0318) accessible through *www.regulations.gov.*

2. Public Involvement Since the April 2009 Proposed Endangerment Finding

The Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases (Proposed Findings) was published on April 24, 2009 (74 FR 18886). The Administrator's proposal was subject to a 60-day public comment period, which ended June 23, 2009, and also included two public hearings. Over 380,000 public comments were received on the Administrator's proposed endangerment and cause or contribute findings, including comments on the elements of the Administrator's April 2009 proposal, the legal issues pertaining to the Administrator's decisions, and the underlying TSD containing the scientific and technical information.

A majority of the comments (approximately 370,000) were the result of mass mail campaigns, which are defined as groups of comments that are identical or very similar in form and content. Overall, about two-thirds of the mass-mail comments received are supportive of the Findings and generally encouraged the Administrator both to make a positive endangerment determination and implement greenhouse gas emission regulations. Of the mass mail campaigns in disagreement with the Proposed Findings most either oppose the proposal on economic grounds (*e.g.,* due to concern for regulatory measures following an endangerment finding) or take issue with the proposed finding that atmospheric greenhouse gas concentrations endanger public health and welfare. Please note that for mass mailer campaigns, a representative copy of the comment is posted in the public docket for this Action (Docket ID No. EPA–HQ–OAR–2009–0171) at *www.regulations.gov.*

Approximately 11,000 other public comments were received. These comments raised a variety of issues related to the scientific and technical information EPA relied upon in making the Proposed Findings, legal and procedural issues, the content of the Proposed Findings, and the implications of the Proposed Findings.

In light of the very large number of comments received and the significant overlap between many comments, EPA has not responded to each comment individually. Rather, EPA has summarized and provided responses to each significant argument, assertion and question contained within the totality of the comments. EPA's responses to some of the most significant comments are provided in these Findings. Responses to all significant issues raised by the comments are contained in the 11 volumes of the Response to Comments document, organized by subject area (found in docket EPA–HQ–OAR–2009–0171).

3. Issues Raised Regarding the Rulemaking Process

EPA received numerous comments on process-related issues, including comments urging the Administrator to delay issuing the final findings, arguing that it was improper for the Administrator to sever the endangerment and cause or contribute findings from the attendant section 202(a) standards, arguing the final decision was preordained by the President's May vehicle announcement, and questioning the adequacy of the comment period. Summaries of key comments and EPA's responses are discussed in this section. Additional and more detailed responses can be found in the Response to Comments document, Volume 11. As noted in the Response to Comments document, EPA also received comments supporting the overall process.

a. It Is Reasonable for the Administrator To Issue the Endangerment and Cause or Contribute Findings Now

Though the Supreme Court did not establish a specific deadline for EPA to act, more than two and a half years have passed since the remand from the Supreme Court, and it has been 10 years since EPA received the original petition requesting that EPA regulate greenhouse gas emissions from new motor vehicles. EPA has a responsibility to respond to the Supreme Court's decision and to fulfill its obligations under current law, and there is good reason to act now given the urgency of the threat of climate change and the compelling scientific evidence.

Many commenters urge EPA to delay making final findings for a variety of reasons. They note that the Supreme Court did not establish a deadline for EPA to act on remand. Commenters also argue that the Supreme Court's decision does not require that EPA make a final endangerment finding, and thus that EPA has discretionary power and may decline to issue an endangerment finding, not only if the science is too uncertain, but also if EPA can provide ''some reasonable explanation'' for exercising its discretion. These commenters interpret the Supreme Court decision not as rejecting all policy reasons for declining to undertake an endangerment finding, but rather as dismissing solely the policy reasons EPA set forth in 2003. Some commenters cite language in the

Supreme Court decision regarding EPA's discretion regarding ''the manner, timing, content, and coordination of its regulations,'' and the Court's declining to rule on ''whether policy concerns can inform EPA's actions in the event that it makes'' a CAA section 202(a) finding to support their position.

Commenters then suggest a variety of policy reasons that EPA can and should make to support a decision not to undertake a finding of endangerment under CAA section 202(a)(1). For example, they argue that a finding of endangerment would trigger several other regulatory programs—such as the Prevention of Significant Deterioration (PSD) provisions—that would impose an unreasonable burden on the economy and government, without providing a benefit to the environment. Some commenters contend that EPA should defer issuing a final endangerment finding while Congress considers legislation. Many commenters note the ongoing international discussions regarding climate change and state their belief that unilateral EPA action would interfere with those negotiations. Others suggest deferring the EPA portion of the joint U.S. Department of Transportation (DOT)/EPA rulemaking because they argue that the new Corporate Average Fuel Economy (CAFE) standards will effectively result in lower greenhouse gas emissions from new motor vehicles, while avoiding the inevitable problems and concerns of regulating greenhouse gases under the CAA.

Other commenters argue that the endangerment determination has to be made on the basis of scientific considerations only. These commenters state that the Court was clear that ''[t]he statutory question is whether sufficient information exists to make an endangerment finding,'' and thus, only if ''the scientific uncertainty is so profound that it precludes EPA from making a reasoned judgment as to whether greenhouse gases contribute to global warming,'' may EPA avoid making a positive or negative endangerment finding. Many commenters urge EPA to take action quickly. They note that it has been 10 years since the original petition requesting that EPA regulate greenhouse gas emissions from motor vehicles was submitted to EPA. They argue that climate change is a serious problem that requires immediate action.

EPA agrees with the commenters who argue that the Supreme Court decision held that EPA is limited to consideration of science when undertaking an endangerment finding, and that we cannot delay issuing a finding due to policy concerns if the science is sufficiently certain (as it is here). The Supreme Court stated that ''EPA can avoid taking further action only if it determines that greenhouse gases do not contribute to climate change or if it provides some reasonable explanation as to why it cannot or will not exercise its discretion to determine whether they do'' 549 U.S. at 533. Some commenters point to this last provision, arguing that the policy reasons they provide are a ''reasonable explanation'' for not moving forward at this time. However, this ignores other language in the decision that clearly indicates that the Court interprets the statute to allow for the consideration only of science. For example, in rejecting the policy concerns expressed by EPA in its 2003 denial of the rulemaking petition, the Court noted that ''it is evident [the policy considerations] have nothing to do with whether greenhouse gas emissions contribute to climate change. Still less do they amount to a reasoned justification for declining to form *a scientific judgment'' Id.* at 533–34 (emphasis added).

Moreover, the Court also held that ''[t]he statutory question is whether sufficient information exists to make an endangerment finding'' *Id.* at 534. Taken as a whole, the Supreme Court's decision clearly indicates that policy reasons do not justify the Administrator avoiding taking further action on the question here.

We also note that the language many commenters quoted from the Supreme Court decision about EPA's discretion regarding the manner, timing and content of Agency actions, and the ability to consider policy concerns, relate to the motor vehicle standards required in the event that EPA makes a positive endangerment finding, and not the finding itself. EPA has long taken the position that it does have such discretion in the standard-setting step under CAA section 202(a).

b. The Administrator Reasonably Proceeded With the Endangerment and Cause or Contribute Findings Separate From the CAA Section 202(a) Standard Rulemaking

As discussed in the Proposed Findings, typically endangerment and cause or contribute findings have been proposed concurrently with proposed standards under various sections of the CAA, including CAA section 202(a). EPA received numerous comments on its decision to propose the endangerment and cause or contribute findings separate from any standards under CAA section 202(a).

Commenters argue that EPA has no authority to issue an endangerment determination under CAA section 202(a) separate and apart from the rulemaking to establish emissions standards under CAA section 202(a). According to these commenters, CAA section 202(a) provides only one reason to issue an endangerment determination, and that is as the basis for promulgating emissions standards for new motor vehicles; thus, it does not authorize such a stand-alone endangerment finding, and EPA may not create its own procedural rules completely divorced from the statutory text. They continue by stating that while CAA section 202(a) says EPA may issue emissions standards conditioned on such a finding, it does not say EPA may first issue an endangerment determination and then issue emissions standards. In addition, they contend, the endangerment proposal and the emissions standards proposal need to be issued together so commenters can fully understand the implications of the endangerment determination. Failure to do so, they argue, deprives the commenters of the opportunity to assess the regulations that will presumably follow from an endangerment finding. They also argue that the expected overlap between reductions in emissions of greenhouse gases from CAA section 202(a) standards issued by EPA and CAFE standards issued by DOT calls into question the basis for the CAA section 202(a) standards and the related endangerment finding, and that EPA is improperly motivated by an attempt to trigger a cascade of regulations under the CAA and/or to promote legislation by Congress.

EPA disagrees with the commenters' claims and arguments. The text of CAA section 202(a) is silent on this issue. It does not specify the timing of an endangerment finding, other than to be clear that emissions standards may not be issued unless such a determination has been made. EPA is exercising the procedural discretion that is provided by CAA section 202(a)'s lack of specific direction. The text of CAA section 202(a) envisions two separate actions by the Administrator: (1) A determination on whether emissions from classes or categories of new motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger, and (2) a separate decision on issuance of appropriate emissions standards for such classes or categories. The procedure followed in this rulemaking, and the companion rulemaking involving emissions standards for light duty motor vehicles, is consistent with CAA section 202(a). EPA will issue final emissions standards for new motor vehicles only if affirmative findings are made concerning contribution and endangerment, and such emissions standards will not be finalized prior to making any such determinations. While it would also be consistent with CAA section 202(a) to issue the greenhouse gas endangerment and contribution findings and emissions standards for new light-duty vehicles in the same rulemaking, *e.g.,* a single proposal covering them and a single final rule covering them, nothing in CAA section 202(a) requires such a procedural approach, and nothing in the approach taken in this case violates the text of CAA section 202(a). Since Congress was silent on this issue, and more than one procedural approach may accomplish the requirements of CAA section 202(a), EPA has the discretion to use the approach considered appropriate in this case. Once the final affirmative contribution and endangerment findings are made, EPA has the authority to issue the final emissions standards for new light-duty motor vehicles; however, as the Supreme Court has noted, the agency has 'significant latitude as to the manner, timing, [and] content * * * of its regulations . * * *' *Massachusetts v. EPA,* 549 U.S. at 533. That includes the discretion to issue them in a separate rulemaking.

Commenters' argument would also lead to the conclusion that EPA could not make an endangerment finding for the entire category of new motor vehicles, as it is doing here, unless EPA also conducted a rulemaking that set emissions standards for all the classes and categories of new motor vehicles at the same time. This narrow procedural limitation would improperly remove discretion that CAA section 202(a) provides to EPA.

EPA has the discretion under CAA section 202(a) to consider classes or categories of new motor vehicles separately or together in making a contribution and endangerment determination. This discretion would be removed under commenters' interpretation, by limiting this to only those cases in which EPA was also ready to issue emissions standards for all of the classes or categories covered by the endangerment finding. However, nothing in the text of CAA section 202(a) places such a limit on EPA's discretion in determining how to group classes or categories of new motor vehicles for purposes of the contribution and endangerment findings. This limitation would not be appropriate, because the issues of contribution and endangerment are separate and distinct from the issues of setting emissions standards. EPA, in this case, is fully prepared to go forward with the contribution and endangerment determination, while it is not ready to proceed with rulemaking for each and every category of new motor vehicles in the first rulemaking to set emissions standards. Section 202(a) of the CAA provides EPA discretion with regard to when and how it conducts its rulemakings to make contribution and endangerment findings, and to set emissions standards, and the text of CAA section 202(a) does not support commenters attempt to limit such discretion.

Concerns have been raised that the failure to issue the proposed endangerment finding and the proposed emissions standard together preclude commenters from assessing and considering the implications of the endangerment finding and the regulations that would likely flow from such a finding. However, commenters have failed to explain how this interferes in any way with their ability to comment on the endangerment finding. In fact it does not interfere, because the two proposals address separate and distinct issues. The endangerment finding concerns the contribution of new motor vehicles to air pollution and the effect of that air pollution on public health or welfare. The emissions standards, which have been proposed (74 FR 49454, September 28, 2009), concern the appropriate regulatory emissions standards if affirmative findings are made on contribution and endangerment. These two proposals address different issues. While commenters have the opportunity to comment on the proposed emissions standards in that rulemaking, they have not shown, and cannot show, that they need to have the emissions standards proposal before them in order to provide relevant comments on the proposed contribution or endangerment findings. Further discussion of this issue can be found in Section II of these Findings, and discussion of the timing of this action and its relationship to other CAA provisions and Congressional action can be found in Section III of these Findings and Volume 11 of the Response to Comments document.

c. The Administrator's Final Decision Was Not Preordained by the President's May Vehicle Announcement

EPA received numerous comments arguing that the President's announcement of a new ''National Fuel Efficiency Policy'' on May 19, 2009 seriously undermines EPA's ability to provide objective consideration of and a legally adequate response to comments objecting to the previously proposed endangerment findings.

Commenters' conclusion is based on the view that the President's announced policy requires EPA to promulgate greenhouse gas emissions standards under CAA section 202(a), that the President's and Administrator Jackson's announcement indicated that the endangerment rulemaking was but a formality and that a final endangerment finding was a fait accompli. Commenters argue that this means the result of this rulemaking has been preordained and the merits of the issues have been prejudged.

EPA disagrees. Commenters' arguments wholly exaggerate and mischaracterize the circumstances. In the April 24, 2009 endangerment proposal EPA was clear that the two steps in the endangerment provision have to be satisfied in order for EPA to issue emissions standards for new motor vehicles under CAA section 202(a) (74 FR at 18888, April 24, 2009). This was repeated when EPA issued the Notice of Upcoming Joint Rulemaking to Establish Vehicle GHG Emissions and CAFE Standards (74 FR 24007 May 22, 2009) (Notice of Intent or NOI). This was repeated again when EPA issued proposed greenhouse gas emissions standards for certain new motor vehicles (74 FR 49454, September 28, 2009). EPA has consistently made it clear that issuance of new motor vehicle standards requires and is contingent upon satisfaction of the two-part endangerment test.

On May 19, 2009 EPA issued the joint Notice of Intent, which indicated EPA's intention to propose new motor vehicle standards. All of the major motor vehicle manufacturers, their trade associations, the State of California, and several environmental organizations announced their full support for the upcoming rulemaking. Not surprisingly, on the same day the President also announced his full support for this action. Commenters, however, erroneously equate this Presidential support with a Presidential directive that requires EPA to prejudge and preordain the result of this rulemaking.

The only evidence they point to are simply indications of Presidential support. Commenters point to a press release, which unsurprisingly refers to the Agency's announcement as delivering on the President's commitment to enact more stringent fuel economy standards, by bringing ''all stakeholders to the table and [coming] up with a plan'' for solving a serious problem. The plan that was announced, of course, was a plan to conduct notice and comment rulemaking. The press release itself states that President Obama ''set in motion a new national policy,'' with the policy ''aimed'' at reducing greenhouse gas emissions for new cars and trucks. What was ''set in motion'' was a notice and comment rulemaking described in the NOI issued by EPA on the same day. Neither the President nor EPA announced a final rule or a final direction that day, but instead did no more than announce a plan to go forward with a notice and comment rulemaking. That is how the plan ''delivers on the President's commitment'' to enact more stringent standards. The announcement was that a notice and comment rulemaking would be initiated with the aim of adopting certain emissions standards.

That is no different from what EPA or any other agency states when it issues a notice of proposed rulemaking. It starts a process that has the aim of issuing final regulations if they are deemed appropriate at the end of the public process. The fact that an Agency proposes a certain result, and expects that a final rule will be the result of setting such a process in motion, is the ordinary course of affairs in notice and comment rulemakings. This does not translate into prejudging the final result or having a preordained result that de facto negates the public comment process. The President's press release of May 19, 2009 was a recognition that this notice and comment rulemaking process would be set in motion, as well as providing his full support for the Agency to go forward in this direction; it was no more than that.

The various stakeholders who announced their support for the plan that had been set in motion all recognized that full notice and comment rulemaking was part of the plan, and they all reserved their rights to participate in such notice and comment rulemaking. For example, see the letter of support from Ford Motor Company, which states that ''Ford fully supports proposal and adoption of such a National Program, which we understand will be subject to full notice-and-comment rulemaking, affording all interested parties including Ford the right to participate fully, comment, and submit information, the results of which are not pre-determined but depend upon processes set by law.''

d. The Notice and Comment Period Was Adequate

Many commenters argue that the 60-day comment period was inadequate. Commenters claim that a 60-day period was insufficient time to fully evaluate the science and other information that informed the Administrator's proposal. Some commenters assert that because the comment period for the Proposed Finding substantially overlapped with the comment period for the Mandatory Greenhouse Gas Reporting Rule, as well as Congress' consideration of climate legislation, their ability to fully participate in the notice and comment period was ''seriously compromised.'' Moreover, they continue, because EPA had not yet proposed CAA section 202(a) standards, there was no valid reason to fail to extend the comment period. Several commenters and other entities had also requested that EPA extend the comment period.

Some commenters assert that the notice provided by this rulemaking was ''defective'' because the **Federal Register** notice announcing the proposal had an error in the e-mail address for the docket. At least one commenter suggests that this error deprives potential commenters of their Due Process under the Fifth Amendment of the Constitution, citing *Armstrong* v. *Manzo,* 380 U.S. 545, 552 (1965), and that failure to ''correct'' the minor typographical error in the e-mail address and extend the comment period would make the rule ''subject to reversal'' in violation of the CAA, Administrative Procedure Act (APA), the Due Process clause of the Constitution, and EO 12866.

Finally, for many of the same reasons that commenters argue a 60-day comment period was inadequate, several commenters request that EPA reopen and/or extend the comment period. One commenter requests that the comment period be reopened because there was new information regarding data used by EPA in the Proposed Findings. In particular, the commenter alleges that it recently became aware that one of the sources of global climate data had destroyed the raw data for its data set of global surface temperatures. The commenter argues that this alleged destruction of raw data violates scientific standards, calls into question EPA's reliance on that data in these Findings, and necessitates a reopening of the proceedings. Other commenters request that the comment period be extended and/or reopened due to the release of a Federal government document on the impact of climate change in the United States near the end of the comment period, as well as the release of an internal EPA staff document discussing the science.

The official public comment period on the proposed rule was adequate. First, a 60-day comment period satisfies the procedural requirements of CAA section 307 of the CAA, which requires a 30-day comment period, and that the docket be kept open to receive rebuttal or supplemental information as follow-up to any hearings for 30 days following the hearings. EPA met those obligations here—the comment period opened on April 24, 2009, the last hearing was on May 21, 2009 and the comment period closed June 23, 2009.

Second, as explained in letters denying requests to extend the comment period, a very large part of the information and analyses for the Proposed Findings had been previously released in July 30, 2008, as part of the *Advance Notice of Proposed Rulemaking: Regulating Greenhouse Gas Emissions under the Clean Air Act (ANPR)* (73 FR 44353). The public comment period for the ANPR is discussed above in Section I.C.1 of these Findings. The Administrator explained that the comment period for that ANPR was 120 days and that the major recent scientific assessments that EPA relied upon in the TSD released with the ANPR had previously each gone through their own public review processes and have been publicly available for some time. In other words, EPA has provided ample time for review, particularly with regard to the technical support for the Findings. See, for example, EPA Letter to Congressman Issa dated June 17, 2009, a copy of which is available at *http://epa.gov/climatechange/endangerment.html*.

Moreover, the comment period was not rendered insufficient merely because other climate-related proceedings were occurring simultaneously.

While one commenter suggests that the convergence of several different climate-related activities has ''seriously compromised'' their ability to participate in the comment process, that commenter was able to submit an 89 page comment on this proposal alone. Moreover, it is hardly rare that more than one rule is out for comment at the same time. As noted above, EPA has received a substantial number of significant comments on the Proposed Findings, and has thoroughly considered and responded to significant comments.

EPA finds no evidence that a typographical error in the docket e-mail address of the **Federal Register** notice announcing the proposal prevented the public from having a meaningful opportunity to comment, and therefore deprived them of due process. Although the minor error—which involved a word processing auto-correction that turned a short dash into a long dash—appeared in the FR version of the Proposed Findings, the e-mail address is correct in the signature version of the Proposed Findings posted on EPA's Web site until publication in the **Federal Register,** and in the ''Instructions for Submitting Written Comments'' document on the Web site for the rulemaking. EPA has received over 190,000 e-mails to the docket e-mail address to date, so the minor typographical error appearing in only one location has not been an impediment to interested parties' e-mailing comments. Moreover, EPA provided many other avenues for interested parties to submit comments in addition to the docket e-mail address, including via *www.regulations.gov,* mail, and fax; each of these options have been utilized by many commenters. EPA is confident that the minor typographical error did not prevent anyone from submitting written comments, by e-mail or otherwise, and that the public was provided ''meaningful participation in the regulatory process'' as mentioned in EO 12866.

Our response regarding the request to reopen the comment period due to concerns about alleged destruction of raw global surface data is discussed more fully in the Response to Comments document, Volume 11. The commenter did not provide any compelling reason to conclude that the absence of these data would materially affect the trends in the temperature records or conclusions drawn about them in the assessment literature and reflected in the TSD. The Hadley Centre/Climate Research Unit (CRU) temperature record (referred to as HadCRUT) is just one of three global surface temperature records that EPA and the assessment literature refer to and cite. National Oceanic and Atmospheric Administration (NOAA) and National Aeronautics and Space Administration (NASA) also produce temperature records, and all three temperature records have been extensively peer reviewed. Analyses of the three global temperature records produce essentially the same long-term trends as noted in the Climate Change Science Program (CCSP) (2006) report ''Temperature Trends in the Lower Atmosphere,'' IPCC (2007), and NOAA's study [5] ''State of the Climate in 2008''. Furthermore, the commenter did not demonstrate that the allegedly destroyed data would materially alter the HadCRUT record or meaningfully hinder its replication. The raw data, a small part of which has not been public (for reasons described at: *https://www.uea.ac.uk/mac/comm/media/press/2009/nov/CRUupdate*), are available in a quality-controlled (or homogenized, value-added) format and the methodology for developing the quality-controlled data is described in the peer reviewed literature (as documented at *http://www.cru.uea.ac.uk/cru/data/temperature/*).

The release of the U.S. Global Climate Research Program (USGCRP) report on impacts of climate change in the United States in June 2009 also did not necessitate extending the comment period. This report was issued by the USGCRP, formerly the Climate Change Science Program (CCSP), and synthesized information contained in prior CCSP reports and other synthesis reports, many of which had already been published (and were included in the TSD for the Proposed Findings). Further, the USGCRP report itself underwent notice and comment before it was finalized and released.

Regarding the internal EPA staff paper that came to light during the comment period, several commenters submitted a copy of the EPA staff paper with their comments; EPA's response to the issues raised by the staff paper are discussed in the Response to Comments document, Volume 1. The fact that some internal agency deliberations were made public during the comment period does not in and of itself call into question those deliberations. As our responses to comments explain, EPA considered the concerns noted in the staff paper during the proposal stage, as well as when finalizing the Findings. There was nothing about those internal comments that required an extension or reopening of the comment period.

Thus, the opportunity for comment fully satisfies the CAA and Constitutional requirement of Due Process. Cases cited by commenters do not indicate otherwise. The comment period and thorough response to comment documents in the docket indicate that EPA has given people an opportunity to be heard in a ''meaningful time and a meaningful matter.'' *Armstrong* v. *Manzo,* 380 U.S. 545, 552 (1965). Interested parties had full notice of the rulemaking proceedings and a significant opportunity to participate through the comment process and multiple hearings.

For all the above reasons, EPA's denial of the requests for extension or reopening of the comment period was entirely reasonable in light of the extensive opportunity for public comment and heavy amount of public participation during the comment period. EPA has fully complied with all applicable public participation requirements for this rulemaking.

e. These Findings Did Not Necessitate a Formal Rulemaking Under the Administrative Procedure Act

One commenter, with the support of others, requests that EPA undertake a formal rulemaking process for the Findings, on the record, in accordance with the procedures described in sections 556–557 of the Administrative Procedure Act (APA). The commenter requests a multi-step process, involving additional public notice, an on-the-record proceeding (*e.g.,* formal administrative hearing) with the right of appeal, utilization of the Clean Air Scientific Advisory Committee (CASAC) and its advisory proceedings, and designation of representatives from other executive branch agencies to participate in the formal proceeding and any CASAC advisory proceeding.

The commenter asserts that while EPA is not obligated under the CAA to undertake these additional procedures, the Agency nonetheless has the legal authority to engage in such a proceeding. The commenter believes this proceeding would show that EPA is ''truly committed to scientific integrity and transparency.'' The commenter cites several cases to argue that refusal to proceed on the record would be ''arbitrary and capricious'' or would be an ''abuse of discretion.'' The allegation at the core of the commenter's argument is that profound and wide-ranging scientific uncertainties exist in the Proposed Findings and in the impacts on health and welfare discussed in the TSD. To support this argument, the commenter provides lengthy criticisms of the science. The commenter also argues that the regulatory cascade that would be ''unleashed'' by a positive endangerment finding warrants the more formal proceedings.

Finally, the commenter suggests that EPA engage in ''formal rulemaking'' procedures in part due to the Administrative Conference of the United States' (ACUS) recommended factors for engaging in formal rulemaking. The commenter argues that the current action is ''complex,'' ''open-ended,'' and the costs that errors in the action may pose are ''significant.''

EPA is denying the request to undertake an ''on the record'' formal rulemaking. EPA is under no obligation to follow the extraordinarily rarely used formal rulemaking provisions of the APA. First, CAA section 307(d) of the CAA clearly states that the rulemaking provisions of CAA section 307(d), *not* APA sections 553 through 557, apply to certain specified actions, such as this

[5] Peterson, T.C., and M.O. Baringer (Eds.) (2009) State of the Climate in 2008. *Bull. Amer. Meteor. Soc.,* 90, S1–S196.

one. EPA has satisfied all the requirements of CAA section 307(d). Indeed, the commenter itself ''is not asserting that the Clean Air Act expressly requires'' the additional procedures it requests. Moreover, the commenter does not discuss how the suggested formal proceeding would fit into the informal rulemaking requirements of CAA section 307(d) that do apply.

Formal rulemaking is very rarely used by Federal agencies. The formal rulemaking provisions of the APA are only triggered when the statute explicitly calls for proceedings ''on the record after opportunity for an agency hearing.'' *United States* v. *Florida East Coast Ry. Co.,* 410 U.S. 224, 241 (1973). The mere mention of the word ''hearing'' does not trigger the formal rulemaking provisions of the APA. *Id.* The CAA does not include the statutory phrase required to trigger the formal rulemaking provisions of the APA (and as noted above the APA does not apply in the first place). Congress specified that certain rulemakings under the CAA follow the rulemaking procedures outlined in CAA section 307(d) rather than the APA ''formal rulemaking'' commenter suggests.

Despite the inapplicability of the formal rulemaking provisions to this action, commenters suggest that to refuse to voluntarily undertake rulemaking provisions not preferred by Congress would make EPA's rulemaking action an ''abuse of discretion.'' EPA disagrees with this claim, and cases cited by the commenter do not indicate otherwise. To support the idea that an agency decision to engage in informal rulemaking could be an abuse of discretion, commenter cites *Ford Motor Co.* v. *FTC,* 673 F.2d 1008 (9th Cir. 1981). In *Ford Motor Co.,* the court ruled that the FTC's decision regarding an automobile dealership should have been resolved through a rulemaking rather than an individualized adjudication. *Id.* at 1010. In that instance, the court favored ''rulemaking'' over adjudication—not ''formal rulemaking'' over the far more common ''informal rulemaking.'' The case stands only for the non-controversial proposition that sometimes agency use of *adjudications* may rise to an abuse of discretion where a *rulemaking* would be more appropriate—whether formal or informal. The Commenter does not cite a single judicial opinion stating that an agency abused its discretion by following the time-tested and Congressionally-favored informal rulemaking provisions of the CAA or the APA instead of the rarely used formal APA rulemaking provisions.

The commenter also alludes to the possibility that the choice of informal rulemaking may be ''arbitrary and capricious. EPA disagrees that the choice to follow the frequently used, and CAA required, informal rulemaking procedures is arbitrary and capricious. The commenter cites *Vermont Yankee Nuclear Power Corp.* v. *NRDC,* 435 U.S. 519 (1978) for the proposition that ''extremely compelling circumstances'' could lead to a court overturning agency action for declining to follow extraneous procedures. As the commenter notes, in *Vermont Yankee* the Supreme Court overturned a lower court decision for imposing additional requirements not required by applicable statutes. Even if the dicta in *Vermont Yankee* could be applied contrary to the holding of the case in the way the commenter suggests, EPA's decision to follow frequently used informal rulemaking procedures for this action is highly reasonable.

As for the ACUS factors the commenter cites in support of its request, as the commenter notes, the ACUS factors are mere recommendations. While EPA certainly respects the views of ACUS, the recommendations are not binding on the Agency. In addition, EPA has engaged in a thorough, traditional rulemaking process that ensures that any concerns expressed by the commenter have been addressed. EPA has fully satisfied all applicable law in their consideration of this rulemaking.

Finally, as explained in Section III of these Findings and the Response to Comments document, EPA's approach to evaluating the evidence before it was entirely reasonable, and did not require a formal hearing. EPA relied primarily on robust synthesis reports that have undergone peer review and comment. The Agency also carefully considered the comments received on the Proposed Findings and TSD, including review of attached studies and documents. The public has had ample opportunity to provide its views on the science, and the record supporting these final findings indicates that EPA carefully considered and responded to significant public comments. To the extent the commenter's concern is that a formal proceeding will help ensure the *right* action in response to climate change is taken, that is not an issue for these Findings. As discussed in Section III of these Findings, this science-based judgment is not the forum for considering the potential mitigation options or their impact.

II. Legal Framework for This Action

As discussed in the Proposed Findings, two statutory provisions of the CAA govern the Administrator's Findings. Section 202(a) of the CAA sets forth a two-part test for regulatory action under that provision: Endangerment and cause or contribute. Section 302 of the CAA contains definitions of the terms ''air pollutant'' and ''effects on welfare''. Below is a brief discussion of these statutory provisions and how they govern the Administrator's decision, as well as a summary of significant legal comments and EPA's responses to them.

A. Section 202(a) of the CAA—Endangerment and Cause or Contribute

1. The Statutory Framework

Section 202(a)(1) of the CAA states that:

The Administrator shall by regulation prescribe (and from time to time revise) standards applicable to the emission of any air pollutant from any class or classes of new motor vehicles or new motor vehicle engines, which in [her] judgment cause, or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare.

Based on the text of CAA section 202(a) and its legislative history, the Administrator interprets the two-part test as follows. Further discussion of this two-part test can be found in Section II of the preamble for the Proposed Findings. First, the Administrator is required to protect public health and welfare, but she is not asked to wait until harm has occurred. EPA must be ready to take regulatory action to prevent harm before it occurs. Section 202(a)(1) requires the Administrator to ''anticipate'' ''danger'' to public health or welfare. The Administrator is thus to consider both current and future risks. Second, the Administrator is to exercise judgment by weighing risks, assessing potential harms, and making reasonable projections of future trends and possibilities. It follows that when exercising her judgment the Administrator balances the likelihood and severity of effects. This balance involves a sliding scale; on one end the severity of the effects may be of great concern, but the likelihood low, while on the other end the severity may be less, but the likelihood high. Under either scenario, the Administrator is permitted to find endangerment. If the harm would be catastrophic, the Administrator is permitted to find endangerment even if the likelihood is small.

Because scientific knowledge is constantly evolving, the Administrator may be called upon to make decisions while recognizing the uncertainties and limitations of the data or information available, as risks to public health or welfare may involve the frontiers of scientific or medical knowledge. At the same time, the Administrator must exercise reasoned decision making, and avoid speculative inquiries. Third, as discussed further below, the Administrator is to consider the cumulative impact of sources of a pollutant in assessing the risks from air pollution, and is not to look only at the risks attributable to a single source or class of sources. Fourth, the Administrator is to consider the risks to all parts of our population, including those who are at greater risk for reasons such as increased susceptibility to adverse health effects. If vulnerable subpopulations are especially at risk, the Administrator is entitled to take that point into account in deciding the question of endangerment. Here too, both likelihood and severity of adverse effects are relevant, including catastrophic scenarios and their probabilities as well as the less severe effects. As explained below, vulnerable subpopulations face serious health risks as a result of climate change.

In addition, by instructing the Administrator to consider whether emissions of an air pollutant cause or contribute to air pollution, the statute is clear that she need not find that emissions from any one sector or group of sources are the sole or even the major part of an air pollution problem. The use of the term ''contribute'' clearly indicates a lower threshold than the sole or major cause. Moreover, the statutory language in CAA section 202(a) does not contain a modifier on its use of the term contribute. Unlike other CAA provisions, it does not require ''significant'' contribution. See, *e.g.,* CAA sections 111(b); 213(a)(2), (4). To be sure, any finding of a ''contribution'' requires some threshold to be met; a truly trivial or de minimis ''contribution'' might not count as such. The Administrator therefore has ample discretion in exercising her reasonable judgment in determining whether, under the circumstances presented, the cause or contribute criterion has been met. Congress made it clear that the Administrator is to exercise her judgment in determining contribution, and authorized regulatory controls to address air pollution even if the air pollution problem results from a wide variety of sources. While the endangerment test looks at the entire air pollution problem and the risks it poses, the cause or contribute test is designed to authorize EPA to identify and then address what may well be many different sectors or groups of sources that are each part of—and thus contributing to—the problem.

This framework recognizes that regulatory agencies such as EPA must be able to deal with the reality that ''[m]an's ability to alter his environment has developed far more rapidly than his ability to foresee with certainty the effects of his alterations.'' See *Ethyl Corp* v. *EPA,* 541 F.2d 1, 6 (DC Cir.), *cert. denied* 426 U.S. 941 (1976). Both ''the Clean Air Act 'and common sense * * * demand regulatory action to prevent harm, even if the regulator is less than certain that harm is otherwise inevitable.' '' See *Massachusetts* v. *EPA,* 549 U.S. at 506, n.7 (citing *Ethyl Corp.*).

The Administrator recognizes that the context for this action is unique. There is a very large and comprehensive base of scientific information that has been developed over many years through a global consensus process involving numerous scientists from many countries and representing many disciplines. She also recognizes that there are varying degrees of uncertainty across many of these scientific issues. It is in this context that she is exercising her judgment and applying the statutory framework. As discussed in the Proposed Findings, this interpretation is based on and supported by the language in CAA section 202(a), its legislative history and case law.

2. Summary of Response to Key Legal Comments on the Interpretation of the CAA Section 202(a) Endangerment and Cause or Contribute Test

EPA received numerous comments regarding the interpretation of CAA section 202(a) set forth in the Proposed Findings. Below is a brief discussion of some of the key adverse legal comments and EPA's responses. Other key legal comments and EPA's responses are provided in later sections discussing the Administrator's findings.

Additional and more detailed summaries and responses can be found in the Response to Comments document. As noted in the Response to Comments document, EPA also received comments supporting its legal interpretations.

a. The Administrator Properly Interpreted the Precautionary and Preventive Nature of the Statutory Language

Various commenters argue either that the endangerment test under CAA section 202(a) is not precautionary and preventive in nature, or that EPA's interpretation and application is so extreme that it is contrary to what Congress intended in 1977, and effectively guarantees an affirmative endangerment finding. Commenters also argue that the endangerment test improperly shifts the burdens to the opponents of an endangerment finding and is tantamount to assuming the air pollution is harmful unless it is shown to be safe.

EPA rejects the argument that the endangerment test in CAA section 202(a) is not precautionary or preventive in nature. As discussed in more detail in the proposal, Congress relied heavily on the en banc decision in Ethyl when it revised section 202(a) and other CAA provisions to adopt the current language on endangerment and contribution. 74 FR 18886, 18891–2. The Ethyl court could not have been clearer on the precautionary nature of a criteria based on endangerment. The court rejected the argument that EPA had to find actual harm was occurring before it could make the required endangerment finding. The court stated that:

> *The Precautionary Nature of ''Will Endanger.''* Simply as a matter of plain meaning, we have difficulty crediting petitioners' reading of the ''will endanger'' standard. The meaning of ''endanger'' is not disputed. Case law and dictionary definition agree that endanger means something less than actual harm. When one is endangered, harm is *threatened;* no actual injury need ever occur. Thus, for example, a town may be ''endangered'' by a threatening plague or hurricane and yet emerge from the danger completely unscathed. A statute allowing for regulation in the face of danger is, necessarily, a precautionary statute. Regulatory action may be taken before the threatened harm occurs; indeed, the very existence of such precautionary legislation would seem to *demand* that regulatory action precede, and, optimally, prevent, the perceived threat. As should be apparent, the ''will endanger'' language of Section 211(c)(1)(A) makes it such a precautionary statute. *Ethyl* at 13 (footnotes omitted).

Similarly, the court stated that ''[i]n sum, based on the plain meaning of the statute, the juxtaposition of CAA section 211 with CAA sections 108 and 202, and the *Reserve Mining* precedent, we conclude that the ''will endanger'' standard is precautionary in nature and does not require proof of actual harm before regulation is appropriate.'' *Ethyl* at 17. It is this authority to act before harm has occurred that makes it a preventive, precautionary provision.

It is important to note that this statement was in the context of rejecting an argument that EPA had to prove actual harm before it could adopt fuel control regulations under then CAA section 211(c)(1). The court likewise rejected the argument that EPA had to show that such harm was ''probable.''

The court made it clear that determining endangerment entails judgments involving both the risk or likelihood of harm and the severity of the harm if it were to occur. Nowhere did the court indicate that the burden was on the opponents of an endangerment finding to show that there was no endangerment. The opinion focuses on describing the burden the statute places on EPA, rejecting *Ethyl's* arguments of a burden to show actual or probable harm.

Congress intentionally adopted a precautionary and preventive approach. It stated that the purpose of the 1977 amendments was to ''emphasize the preventive or precautionary nature of the act, *i.e.,* to assure that regulatory action can effectively prevent harm before it occurs; to emphasize the predominate value of protection to public health.'' [6] Congress also stated that it authorized the Administrator to weigh risks and make projections of future trends, a ''middle road between those who would impose a nearly impossible standard of proof on the Administrator before he may move to protect public health and those who would shift the burden of proof for all pollutants to make the pollutant source prove the safety of its emissions as a condition of operation.'' Leg. His. at 2516.

Thus, EPA rejects commenters' arguments. Congress intended this provision to be preventive and precautionary in nature, however it did not shift the burden of proof to opponents of an endangerment finding to show safety or no endangerment. Moreover, as is demonstrated in the following, EPA has not shifted the burden of proof in the final endangerment finding, but rather is weighing the likelihood and severity of harms to arrive at the final finding. EPA has not applied an exaggerated or dramatically expanded precautionary principle, and instead has exercised judgment by weighing and balancing the factors that are relevant under this provision.

b. The Administrator Does Not Need To Find That the Control Measures Following an Endangerment Finding Would Prevent at Least a Substantial Part of the Danger in Order To Find Endangerment

Several commenters argue that it is unlawful for EPA to make an affirmative endangerment finding unless EPA finds that the regulatory control measures contemplated to follow such a finding would prevent at least a substantial part of the danger from the global climate change at which the regulation is aimed. This hurdle is also described by commenters as the regulation ''achieving the statutory objective of preventing damage'', or ''fruitfully attacking'' the environmental and public health danger at hand by meaningfully and substantially reducing it. Commenters point to *Ethyl Corp.* v. *EPA,* 541 F.2d 1 (DC Cir. 1976) (en banc) as support for this view, as well as portions of the legislative history of this provision.

Commenters contend that EPA has failed to show that this required degree of meaningful reduction of endangerment would be achieved through regulation of new motor vehicles based on an endangerment finding. In making any such showing, commenters argue that EPA would need to account for the following: (1) The fact that any regulation would be limited to *new* motor vehicles, if not the subset of new motor vehicles discussed in the President's May 2009 announcement, (2) any increase in emissions from purchasers delaying purchases of new vehicles subject to any greenhouse gas emissions standards, or increasing the miles traveled of new vehicles with greater fuel economy, (3) the fact that only a limited portion of the new motor vehicle emissions of greenhouse gases would be controlled, (4) the fact that CAFE standards would effectively achieve the same reductions, and (5) the fact that any vehicle standards would not themselves reduce global temperatures. Some commenters refer to EPA's proposal for greenhouse gas emissions standards for new motor vehicles as support for these arguments, claiming the proposed new motor vehicle emission standards are largely duplicative of the standards proposed by the National Highway Traffic Safety Administration (NHTSA), and the estimates of the impacts of the proposed standards confirm that EPA's proposed standards cannot ''fruitfully attack'' global climate change (74 FR 49454, September 28, 2009).

Commenters attempt to read into the statute a requirement that is not there. EPA interprets the endangerment provision of CAA section 202(a) as not requiring any such finding or showing as described by commenters. The text of CAA section 202(a) does not support such an interpretation. The endangerment provision calls for EPA, in its judgment, to determine whether air pollution is reasonably anticipated to endanger public health or welfare, and whether emissions from certain sources cause or contribute to such air pollution. If EPA makes an affirmative finding, then it shall set emissions standards applicable to emissions of such air pollutants from new motor vehicles. There is no reference in the text of the endangerment or cause or contribute provision to anything concerning the degree of reductions that would be achieved by the emissions standards that would follow such a finding. The Administrator's judgment is directed at the issues of endangerment and cause or contribute, not at how effective the resulting emissions control standards will be.

As in the several other similar provisions adopted in the 1977 amendments, in CAA section 202(a) Congress explicitly separated two different decisions to be made, providing different criteria for them. The first decision involves the air pollution and the endangerment criteria, and the contribution to the air pollution by the sources. The second decision involves how to regulate the sources to control the emissions if an affirmative endangerment and contribution finding are made. In all of the various provisions, there is broad similarity in the phrasing of the endangerment and contribution decision. However, for the decision on how to regulate, there are a wide variety of different approaches adopted by Congress. In some case, EPA has discretion whether to issue standards or not, while in other cases, as in CAA section 202(a), EPA is required to issue standards. In some cases, the regulatory criteria are general, as in CAA section 202(a); in others, they provide significantly more direction as to how standards are to be set, as in CAA section 213(a)(4).

As the Supreme Court made clear in *Massachusetts* v. *EPA,* EPA's judgment in making the endangerment and contribution findings is constrained by the statute, and EPA is to decide these issues based solely on the scientific and other evidence relevant to that decision. EPA may not ''rest[] on reasoning divorced from the statutory text,'' and instead EPA's exercise of judgment must relate to whether an air pollutant causes or contributes to air pollution that endangers. *Massachusetts* v. *EPA,* 549 U.S. at 532. As the Supreme Court noted, EPA must ''exercise discretion within defined statutory limits.'' Id. at 533. EPA's belief one way or the other regarding whether regulation of greenhouse gases from new motor vehicles would be ''effective'' is irrelevant in making the endangerment and contribution decisions before EPA. Id. Instead ''[t]he statutory question is

[6] The Supreme Court recognized that the current language in section 202(a), adopted in 1977, is ''more protective'' than the 1970 version that was similar to the section 211 language before the DC Circuit in *Ethyl. Massachusetts* v. *EPA,* 549 U.S. at 506, fn 7.

whether sufficient information exists to make an endangerment finding'' Id. at 534.

The effectiveness of a potential future control strategy is not relevant to deciding whether air pollution levels in the atmosphere endanger. It is also not relevant to deciding whether emissions of greenhouse gases from new motor vehicles contribute to such air pollution. Commenters argue that Congress implicitly imposed a third requirement, that the future control strategy have a certain degree of effectiveness in reducing the endangerment before EPA could make the affirmative findings that would authorize such regulation. There is no statutory text that supports such an interpretation, and the Supreme Court makes it clear that EPA has no discretion to read this kind of additional factor into CAA section 202(a)'s endangerment and contribution criteria. In fact, the Supreme Court rejected similar arguments that EPA had the discretion to consider various other factors besides endangerment and contribution in deciding whether to deny a petition. *Massachusetts* v. *EPA,* 549 U.S. at 532–35.

Commenters point to language from the *Ethyl* case to support their position, noting that the DC Circuit referred to the emissions control regulation adopted by EPA under CAA section 211(c) as one that would ''fruitfully attack'' the environmental and public health danger by meaningfully and substantially reducing the danger. It is important to understand the context for this discussion in *Ethyl.* The petitioner *Ethyl Corp.* argued that EPA had to show that the health threat from the emissions of lead from the fuel additive being regulated had to be considered in isolation, and the threat ''in and of itself'' from the additive had to meet the test of endangerment in CAA section 211(c). EPA had rejected this approach, and had interpreted CAA section 211(c)(1) as calling for EPA to look at the cumulative impact of lead, and to consider the impact of lead from emissions related to use of the fuel additive in the context all other human exposure to lead. The court rejected *Ethyl's* approach and supported EPA's interpretation. The DC Circuit noted that Congress was fully aware that the burden of lead on the body was caused by multiple sources and that it would be of no value to try and determine the effect on human health from the lead automobile emissions by themselves. The court specifically noted that ''the incremental effect of lead emissions on the total body lead burden is of no practical value in determining whether health is endangered,'' but recognized that this incremental effect is of value ''in deciding whether the lead exposure problem can fruitfully be attacked through control of lead additives.'' *Ethyl,* 541 F.2d at 31 fn 62. The court made clear that the factor that was critically important to determining the effectiveness of the resulting control strategy—the incremental effect of automobile lead emissions on total body burden—was irrelevant and of no value in determining whether the endangerment criteria was met. Thus it is clear that the court in *Ethyl* did not interpret then CAA section 211(c)(1)(A) as requiring EPA to make a showing of the effectiveness of the resulting emissions control strategy, and instead found just the opposite, that the factors that would determine effectiveness are irrelevant to determining endangerment.

Commenters also cite to the legislative history, noting that Congress referred to the ''preventive or precautionary nature of the Act, *i.e.,* to assure that regulatory action can effectively prevent harm before it occurs.'' Leg. Hist. at 2516. However, this statement by Congress is presented as an answer to the question on page 2515, ''Should the Administrator act to prevent harm before it occurs or should he be authorized to regulate an air pollutant only if he finds actual harm has already occurred.'' Leg. Hist. at 2515. In this context, the discussion on page 2516 clearly indicates that there is no opportunity for prevention or precaution if the test is one of actual harm already occurring. This discussion does not say or imply that even if the harm has not occurred, you can not act unless you also show that your action will effectively address it. This discussion concerns the endangerment test, not the criteria for standard setting. The criteria for standard setting address how the agency should act to address the harm, and as the *Ethyl* case notes, the factors relevant to how to ''fruitfully attack'' the harm are irrelevant to determining whether the harm is one that endangers the public health or welfare.

As with current CAA section 202(a), there is no basis to conflate these two separate decisions and to read into the endangerment criteria an obligation that EPA show that the resulting emissions control strategy or strategies will have some significant degree of harm reduction or effectiveness in addressing the endangerment. The conflating of the two decisions is not supported in the text of this provision, by the Supreme Court in *Massachusetts* v. *EPA,* by the DC Circuit in *Ethyl,* or by Congress in the legislative history of this provision. It would be an unworkable interpretation, calling for EPA to project out the result of perhaps not one, but even several, future rulemakings stretching over perhaps a decade or decades. Especially in the context of global climate change, the effectiveness of a control strategy for new motor vehicles would have to be viewed in the context of a number of future motor vehicle regulations, as well as in the larger context of the CAA and perhaps even global context. That would be an unworkable and speculative requirement to impose on EPA as a precondition to answering the public health and welfare issues before it, as they are separate and apart from the issues involved with developing, implementing and evaluating the effectiveness of emissions control strategies.

c. The Administrator Does Not Need To Find There Is Significant Risk of Harm

Commenters argue that Congress established a minimum requirement that there be a ''significant risk of harm'' to find endangerment. They contend that this requirement stemmed from the *Ethyl* case, and that Congress adopted this view. According to the commenters, the risk is the function of two variables: the nature of the hazard at issue and the likelihood of its occurrence. Commenters argue that Congress imposed a requirement that this balance demonstrate a ''significant risk of harm'' to strike a balance between the precautionary nature of the CAA and the burdensome economic and societal consequences of regulation.

There are two basic problems with the commenters' arguments. First, commenters equate ''significant risk of harm'' as the overall test for endangerment, however the *Ethyl* case and the legislative history treat the risk of harm as only one of the two components that are to be considered in determining endangerment.—, The two components are the likelihood or risk of a harm occurring, and the severity of harm if it were to occur. Second, commenters equate it to a minimum statutory requirement. However, while the court in the *Ethyl* case made it clear that the facts in that case met the then applicable endangerment criteria, it also clearly said it was not determining what other facts or circumstances might amount to endangerment, including cases where the likelihood of a harm occurring was less than a significant risk of the harm.

In the EPA rulemaking that led to the *Ethyl* case, EPA stated that the requirement to reduce lead in gasoline ''is based on the finding that lead particle emissions from motor vehicles present a significant risk of harm to the health of urban populations, particularly to the health of city children'' (38 FR 33734, December 6, 1973). The court in *Ethyl* supported EPA's determination, and addressed a variety of issues. First, it determined that the ''will endanger'' criteria of then CAA section 211(c) was intended to be precautionary in nature. It rejected arguments that EPA had to show proof of actual harm, or probable harm. *Ethyl,* 541 F.2d at 13–20. It was in this context, evaluating petitioner's arguments on whether the likelihood of a harm occurring had to rise to the level of actual or probable harm, that the court approved of EPA's view that a significant risk of harm could satisfy the statutory criteria. The precautionary nature of the provision meant that EPA did not need to show that either harm was actually occurring or was probable.

Instead, the court made it clear that the concept of endangerment is ''composed of reciprocal elements of risk and harm,'' *Ethyl* at 18. This means ''the public health may properly be found endangered both by a lesser risk of a greater harm and by a greater risk of lesser harm. Danger depends upon the relation between the risk and harm presented by each case, and cannot legitimately be pegged to 'probable' harm, regardless of whether that harm be great or small.'' The Ethyl court pointed to the decision by the 8th Circuit in *Reserve Mining Co.* v. *EPA,* 514 F.2d 492 (8th Cir, 1975), which interpreted similar language under the Federal Water Pollution Control Act, where the 8th Circuit upheld an endangerment finding in a case involving ''reasonable medical concern,'' or a ''potential'' showing of harm. This was further evidence that a minimum ''probable'' likelihood of harm was not required.

The Ethyl court made it clear that there was no specific magnitude of risk of harm occurring that was required. ''Reserve Mining convincingly demonstrates that the magnitude of risk sufficient to justify regulation is inversely proportional to the harm to be avoided.'' *Ethyl* at 19. This means there is no minimum requirement that the magnitude of risk be ''significant'' or another specific level of likelihood of occurrence. You need to evaluate the risk of harm in the context of the severity of the harm if it were to occur. In the case before it, the Ethyl court noted that ''the harm caused by lead poisoning is severe.'' Even with harm as severe as lead poisoning, EPA did not rely on ''potential'' risk or a ''reasonable medical concern.'' Instead, EPA found that there was a significant risk of this harm to health. This finding of a significant risk was less than the level of ''probable'' harm called for by the petitioner Ethyl Corporation but was ''considerably more certain than the risk that justified regulation in Reserve Mining of a comparably 'fright-laden' harm.'' *Ethyl* at 19–20. The Ethyl court concluded that this combination of risk (likelihood of harm) and severity of harm was sufficient under CAA section 211(c). ''Thus we conclude that however far the parameters of risk and harm inherent in the 'will endanger' standard might reach in an appropriate case, they certainly present a 'danger' that can be regulated when the harm to be avoided is widespread lead poisoning and the risk of that occurrence is 'significant'.'' *Ethyl* at 20.

Thus, the court made it clear that the endangerment criteria was intended to be precautionary in nature, that the risk of harm was one of the elements to consider in determining endangerment, and that the risk of harm needed to be considered in the context of the severity of the potential harm. It also concluded that a significant risk of harm coupled with an appropriate severity of the potential harm would satisfy the statutory criteria, and in the case before it the Administrator was clearly authorized to determine endangerment where there was a significant risk of harm that was coupled with a severe harm such as lead poisoning.

Importantly, the court also made it clear that it was not determining a minimum threshold that always had to be met. Instead, it emphasized that the risk of harm and severity of the potential harm had to be evaluated on a case by case basis. The court specifically said it was not determining ''however far the parameters of risk and harm * * * might reach in an appropriate case.'' *Ethyl* at 20. Also see *Ethyl* fn 17 at 13. The court recognized that this balancing of risk and harm ''must be confined to reasonable limits'' and even absolute certainty of a de minimis harm might not justify government action. However, ''whether a particular combination of slight risk and great harm, or great risk and slight harm constitutes a danger must depend on the facts of each case.'' *Ethyl* at fn 32 at 18.[7]

In some cases, commenters confuse matters by switching the terminology, and instead refer to effects that ''significantly harm'' the public health or welfare. As with the reference to ''significant risk of harm,'' commenters fail to recognize that there are two different aspects that must be considered, risk of harm and severity of harm, and neither of these aspects has a requirement that there be a finding of ''significance.'' The DC Circuit in *Ethyl* makes clear that it is the combination of these two aspects that must be evaluated for purposes of endangerment, and there is no requirement of ''significance'' assigned to either of the two aspects that must instead be evaluated in combination. Congress addressed concerns over burdensome economic and societal consequences in the various statutory provisions that provide the criteria for standard setting or other agency action if there is an affirmative endangerment finding. Those statutory provisions, for example, make standard setting discretionary or specify how cost and other factors are to be taken into consideration in setting standards. However, the issues of risk of harm and severity of harm if it were to occur are separate from the issues of the economic impacts of any resulting regulatory provisions (*see* below).

As is clear in the prior summary of the endangerment findings and the more detailed discussion later, the breadth of the sectors of our society that are affected by climate change and the time frames at issue mean there is a very wide range of risks and harms that need to be considered, from evidence of various harms occurring now to evidence of risks of future harms. The Administrator has determined that the body of scientific evidence compellingly supports her endangerment finding.

B. Air Pollutant, Public Health and Welfare

The CAA defines both ''air pollutant'' and ''effects on welfare.'' We provide both definitions here again for convenience.

Air pollutant is defined as:

[7] Commenters point to *Amer. Farm Bureau Ass'n* v. *EPA,* 559 F.3d 512, 533 (DC Cir. 2009) as supporting their argument. However, in that case the Court made clear that EPA's action was not subject to the endangerment criterion in CAA section 108 but instead was subject to CAA section 109's requirement that the primary NAAQS be requisite to protect the public health with an adequate margin of safety. Under that provision and its case law, the Court upheld EPA's reasoned balancing of the uncertainty regarding the link between non-urban thoracic coarse PM and adverse health effects, the large population groups potentially exposed to these particles, and the nature and degree of the health effects at issue. Citing to EPA's reasoning at 71 FR 61193 in the final PM rule, the court explained that EPA need not wait for conclusive proof of harm before setting a NAAQS under section 109 for this kind of coarse PM. The Court's reference to EPA's belief that there may be a significant risk to public health is not stated as any sort of statutory minimum, but instead refers to the Agency's reasoning at 71 FR 61193, which displays a reasoned balancing of possibility of harm and severity of harm if it were to occur.

''Any air pollution agent or combination of such agents, including any physical, chemical, biological, radioactive (including source material, special nuclear material, and byproduct material) substance or matter which is emitted into or otherwise enters the ambient air. Such term includes any precursors to the formation of any air pollutant, to the extent the Administrator has identified such precursor or precursors for the particular purpose for which the term ''air pollutant'' is used.'' CAA section 302(g). As the Supreme Court held, greenhouse gases fit well within this capacious definition. *See Massachusetts* v. *EPA,* 549 U.S. at 532. They are ''without a doubt'' physical chemical substances emitted into the ambient air. *Id.* at 529.

''Regarding 'effects on welfare', the CAA states that [a]ll language referring to effects on welfare includes, but is not limited to, effects on soils, water, crops, vegetation, man-made materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being, whether caused by transformation, conversion, or combination with other air pollutants.'' CAA section 302(h).

As noted in the Proposed Findings, this definition is quite broad. Importantly, it is not an exclusive list due to the use of the term ''includes, but is not limited to, * * * .'' Effects other than those listed here may also be considered effects on welfare. Moreover, the terms contained within the definition are themselves expansive.

Although the CAA defines ''effects on welfare'' as discussed above, there are no definitions of ''public health'' or ''public welfare'' in the CAA. The Supreme Court has discussed the concept of public health in the context of whether costs of implementation can be considered when setting the health based primary National Ambient Air Quality Standards. *Whitman v. American Trucking Ass'n,* 531 U.S. 457 (2001). In *Whitman,* the Court imbued the term with its most natural meaning: ''the health of the public. *Id.* at 466. In the past, when considering public health, EPA has looked at morbidity, such as impairment of lung function, aggravation of respiratory and cardiovascular disease, and other acute and chronic health effects, as well as mortality. *See, e.g., Final National Ambient Air Quality Standard for Ozone,* (73 FR 16436, 2007).

EPA received numerous comments regarding its proposed interpretations of air pollutant and public health and welfare. Summaries of key comments and EPA's responses are discussed in Sections IV and V of these Findings. Additional and more detailed summaries and responses can be found in the Response to Comments document. As noted in the Response to Comments document, EPA also received comments supporting its legal interpretations.

III. EPA's Approach for Evaluating the Evidence Before It

This section discusses EPA's approach to evaluating the evidence before it, including the approach taken to the scientific evidence, the legal framework for this decision making, and several issues critical to determining the scope of the evaluation performed.

A. The Science on Which the Decisions Are Based

In 2007, EPA initiated its assessment of the science and other technical information to use in addressing the endangerment and cause or contribute issues before it under CAA section 202(a). This scientific and technical information was developed in the form of a TSD in 2007. An earlier draft of this document was released as part of the ANPR published July 30, 2008 (73 FR 44353). That earlier draft of the TSD relied heavily on the IPCC Fourth Assessment Report of 2007, key NRC reports, and a limited number of then-available synthesis and assessment products of the U.S. Climate Change Science Program (CCSP; now encompassed by USGCRP). EPA received a number of comments specifically focused on the TSD during the 120-day public comment period for the ANPR.

EPA revised and updated the TSD in preparing the Proposed Findings on endangerment and cause or contribute. Many of the comments received on the ANPR were reflected in the draft TSD released in April 2009 that served as the underlying scientific and technical basis for the Administrator's Proposed Findings, published April 24, 2009 (74 FR 18886). The draft TSD released in April 2009 also reflected the findings of 11 new synthesis and assessment products under the U.S. CCSP that had been published since July 2008.

The TSD that summarizes scientific findings from the major assessments of the USGCRP, the IPCC, and the NRC accompanies these Findings. The TSD is available at *www.epa.gov/climatechange/endangerment.html* and in the docket for this action. It also includes the most recent comprehensive assessment of the USGCRP, *Global Climate Change Impacts in the United States*,[8] published in June 2009. In addition, the TSD incorporates up-to-date observational data for a number of key climate variables from the NOAA, and the most up-to-date emissions data from EPA's annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks,* published in April, 2009.[9] And finally, as discussed in Section I.B of these Findings, EPA received a large number of public comments on the Administrator's Proposed Findings, many of which addressed science issues either generally or specifically as reflected in the draft TSD released with the April 2009 proposal. A number of edits and updates were made to the draft TSD as a result of these comments.[10]

EPA is giving careful consideration to all of the scientific and technical information in the record, as discussed below. However, the Administrator is relying on the major assessments of the USGCRP, IPCC, and NRC as the primary scientific and technical basis of her endangerment decision for a number of reasons.

First, these assessments address the scientific issues that the Administrator must examine for the endangerment analysis. When viewed in total, these assessments address the issue of greenhouse gas endangerment by providing data and information on: (1) The amount of greenhouse gases being emitted by human activities; (2) how greenhouse gases have been and continue to accumulate in the atmosphere as a result of human activities; (3) changes to the Earth's energy balance as a result of the buildup of atmospheric greenhouse gases; (4) observed temperature and other climatic changes at the global and regional scales; (5) observed changes in other climate-sensitive sectors and systems of the human and natural environment; (6) the extent to which observed climate change and other changes in climate-sensitive systems can be attributed to the human-induced buildup of atmospheric greenhouse gases; (7) future projected climate change under a range of different scenarios of changing greenhouse gas emission rates; and (8) the projected risks and impacts to

[8] Karl, T., J. Melillo, and T. Peterson (Eds.) (2009) Global Climate Change Impacts in the United States. Cambridge University Press, Cambridge, United Kingdom.

[9] U.S. EPA (2009) *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2007.* EPA–430–R–09–004, Washington, DC.

[10] EPA has placed within the docket a separate memo ''Summary of Major Changes to the Technical Support Document'' identifying where within the TSD such changes were made relative to the draft TSD released in April 2009.

human health, society and the environment.

Second, as indicated above, these assessments are recent and represent the current state of knowledge on the key elements for the endangerment analysis. It is worth noting that the June 2009 assessment of the USGCRP incorporates a number of key findings from the 2007 IPCC Fourth Assessment Report; such findings include the attribution of observed climate change to human emissions of greenhouse gases, and the future projected scenarios of climate change for the global and regional scales. This demonstrates that much of the underlying science that EPA has been utilizing since 2007 has not only been in the public domain for some time, but also has remained relevant and robust.

Third, these assessments are comprehensive in their coverage of the greenhouse gas and climate change problem, and address the different stages of the emissions-to-potential-harm chain necessary for the endangerment analysis. In so doing, they evaluate the findings of numerous individual peer-reviewed studies in order to draw more general and overarching conclusions about the state of science. The USGCRP, IPCC, and NRC assessments synthesize literally thousands of individual studies and convey the consensus conclusions on what the body of scientific literature tells us.

Fourth, these assessment reports undergo a rigorous and exacting standard of peer review by the expert community, as well as rigorous levels of U.S. government review and acceptance. Individual studies that appear in scientific journals, even if peer reviewed, do not go through as many review stages, nor are they reviewed and commented on by as many scientists. The review processes of the IPCC, USGCRP, and NRC (explained in fuller detail in the TSD and the Response to Comments document, Volume 1) provide EPA with strong assurance that this material has been well vetted by both the climate change research community and by the U.S. government. These assessments therefore essentially represent the U.S. government's view of the state of knowledge on greenhouse gases and climate change. For example, with regard to government acceptance and approval of IPCC assessment reports, the USGCRP Web site states that: ''When governments accept the IPCC reports and approve their Summary for Policymakers, they acknowledge the legitimacy of their scientific content.'' [11] It is the Administrator's view that such review and acceptance by the U.S. Government lends further support for placing primary weight on these major assessments.

It is EPA's view that the scientific assessments of the IPCC, USGRCP, and the NRC represent the best reference materials for determining the general state of knowledge on the scientific and technical issues before the agency in making an endangerment decision. No other source of information provides such a comprehensive and in-depth analysis across such a large body of scientific studies, adheres to such a high and exacting standard of peer review, and synthesizes the resulting consensus view of a large body of scientific experts across the world. For these reasons, the Administrator is placing primary and significant weight on these assessment reports in making her decision on endangerment.

A number of commenters called upon EPA to perform a new and independent assessment of all of the underlying climate change science, separate and apart from USGCRP, IPCC, and NRC. In effect, commenters suggest that EPA is either required to or should ignore the attributes discussed above concerning these assessment reports, and should instead perform its own assessment of all of the underlying studies and information.

In addition to the significant reasons discussed above for relying on and placing primary weight on these assessment reports, EPA has been a very active part of the U.S. government climate change research enterprise, and has taken an active part in the review, writing, and approval of these assessments. EPA was the lead agency for three significant reports under the USGCRP [12], and recently completed an assessment addressing the climate change impacts on U.S. air quality—a report on which the TSD heavily relies for that particular issue. EPA was also involved in review of the IPCC Fourth Assessment Report, and in particular took part in the approval of the summary for policymakers for the Working Group II Volume, *Impacts, Adaptation and Vulnerability.*[13] The USGCRP, IPCC, and NRC assessments have been reviewed and formally accepted by, commissioned by, or in some cases authored by, U.S. government agencies and individual government scientists. These reports already reflect significant input from EPA's scientists and the scientists of many other government agencies.

EPA has no reason to believe that the assessment reports do not represent the best source material to determine the state of science and the consensus view of the world's scientific experts on the issues central to making an endangerment decision with respect to greenhouse gases. EPA also has no reason to believe that putting this significant body of work aside and attempting to develop a new and separate assessment would provide any better basis for making the endangerment decision, especially because any such new assessment by EPA would still have to give proper weight to these same consensus assessment reports.

In summary, EPA concludes that its reliance on existing and recent synthesis and assessment reports is entirely reasonable and allows EPA to rely on the best available science.[14] EPA also recognizes that scientific research is very active in many areas addressed in the TSD (*e.g.,* aerosol effects on climate, climate feedbacks such as water vapor, and internal and external climate forcing mechanisms), as well as for some emerging issues (*e.g.,* ocean acidification and climate change effects on water quality). EPA recognizes the potential importance of new scientific research, and the value of an ongoing process to take more recent science into account. EPA reviewed new literature in

[11] *http://www.globalchange.gov/publications/reports/ipcc-reports.*

[12] CCSP (2009) *Coastal Sensitivity to Sea-Level Rise: A Focus on the Mid-Atlantic Region.* A Report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. [James G. Titus (Coordinating Lead Author), K. Eric Anderson, Donald R. Cahoon, Dean B. Gesch, Stephen K. Gill, Benjamin T. Gutierrez, E. Robert Thieler, and S. Jeffress Williams (Lead Authors)], U.S. Environmental Protection Agency, Washington DC, USA, 320 pp. CCSP (2008) *Preliminary review of adaptation options for climate-sensitive ecosystems and resources.* A Report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. [Julius, S.H., J.M. West (eds.), J.S. Baron, B. Griffith, L.A. Joyce, P. Kareiva, B.D. Keller, M.A. Palmer, C.H. Peterson, and J.M. Scott (Authors)]. U.S. Environmental Protection Agency, Washington, DC, USA, 873 pp. CCSP (2008) *Analyses of the effects of global change on human health and welfare and human systems.* A Report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. [Gamble, J.L. (ed.), K.L. Ebi, F.G. Sussman, T.J. Wilbanks, (Authors)]. U.S. Environmental Protection Agency, Washington, DC, USA.

[13] IPCC (2007) Climate Change 2007: *Impacts, Adaptation and Vulnerability.* Contribution of Working Group II to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, M.L. Parry, O.F. Canziani, J.P. Palutikof, P.J. van der Linden and C.E. Hanson, Eds., Cambridge University Press, Cambridge, UK, 976pp.

[14] It maintains the highest level of adherence to Agency and OMB guidelines for data and scientific integrity and transparency. This is discussed in greater detail in EPA's Response to Comments document.

preparation of this TSD to evaluate its consistency with recent scientific assessments. We also considered public comments received and studies incorporated by reference. In a number of cases, the TSD was updated based on such information to add context for assessment literature findings, which includes supporting information and/or qualifying statements. In other cases, material that was not incorporated into the TSD is discussed within the Response to Comments document.

EPA reviewed these individual studies that were not considered or reflected in these major assessments to evaluate how they inform our understanding of how greenhouse gas emissions affect climate change, and how climate change may affect public health and welfare. Given the very large body of studies reviewed and assessed in developing the assessment reports, and the rigor and breadth of that review and assessment, EPA placed limited weight on the much smaller number of individual studies that were not considered or reflected in the major assessments. EPA reviewed them largely to see if they would lead EPA to change or place less weight on the judgments reflected in the assessment report. While EPA recognizes that some studies are more useful or informative than others, and gave each study it reviewed the weight it was due, the overall conclusion EPA drew from its review of studies submitted by commenters was that the studies did not change the various conclusions or judgments EPA would draw based on the assessment reports.

Many comments focus on the scientific and technical data underlying the Proposed Findings, such as climate change science and greenhouse gas emissions data. These comments cover a range of topics and are summarized and responded to in the Response to Public Comments document. The responses note those cases where a technical or scientific comment resulted in an editorial or substantive change to the TSD. The final TSD reflects all changes made as a result of public comments.

B. The Law on Which the Decisions Are Based

In addition to grounding these determinations on the science, they are also firmly grounded in EPA's legal authority. Section II of these Findings provides an in-depth discussion of the legal framework for the endangerment and cause or contribute decisions under CAA section 202(a), with additional discussion in Section II of the Proposed Finding (74 FR 18886, 18890, April 24, 2009). A variety of important legal issues are also discussed in Sections III, IV, and V of these Findings, as well as in the Response to Comments document, Volume 11. Section IV and V of these Findings explain the Administrator's decisions, and how she exercised her judgment in making the endangerment and contribution determinations, based on the entire scientific record before her and the legal framework structuring her decision making.

C. Adaptation and Mitigation

Following the language of CAA section 202(a), in which the Administrator, in her judgment, must determine if greenhouse gases constitute the air pollution that may be reasonably anticipated to endanger public health or welfare, EPA evaluated, based primarily on the scientific reports discussed above, how greenhouse gases and other climate-relevant substances are affecting the atmosphere and climate, and how these climate changes affect public health and welfare, now and in the future. Consistent with EPA's scientific approach underlying the Administrator's Proposed Findings, EPA did not undertake a separate analysis to evaluate potential societal and policy responses to any threat (*i.e.,* the endangerment) that may exist due to anthropogenic emissions of greenhouse gases. Risk reduction through adaptation and greenhouse gas mitigation measures is of course a strong focal area of scientists and policy makers, including EPA; however, EPA considers adaptation and mitigation to be potential responses to endangerment, and as such has determined that they are outside the scope of the endangerment analysis.

The Administrator's position is not that adaptation will not occur or cannot help protect public health and welfare from certain impacts of climate change, as some commenters intimated. To the contrary, EPA recognizes that some level of autonomous adaptation [15] will occur, and commenters are correct that autonomous adaptation can affect the severity of climate change impacts. Indeed, there are some cases in the TSD in which some degree of adaptation is accounted for; these cases occur where the literature on which the TSD relies already uses assumptions about autonomous adaptation when projecting the future effects of climate change. Such cases are noted in the TSD. We also view planned adaptation as an important near-term risk-minimizing strategy given that some degree of climate change will continue to occur as a result of past and current emissions of greenhouse gases that remain in the atmosphere for decades to centuries.

However, it is the Administrator's position that projections of adaptation and mitigation in response to risks and impacts associated with climate change are not appropriate for EPA to consider in making a decision on whether the air pollution endangers. The issue before EPA involves evaluating the risks to public health and welfare from the air pollution if we do not take action to address it. Adaptation and mitigation address an important but different issue—how much risk will remain assuming some projection of how people and society will respond to the threat.

Several commenters argue that it is arbitrary not to consider adaptation in determining endangerment. They contend that because endangerment is a forward-looking exercise, the fundamental inquiry concerns the type and extent of harm that is believed likely to occur in the future. Just as the Administrator makes projections of potential harms in the future, these commenters contend that the Administrator needs to consider the literature on adaptation that addresses the likelihood and the severity of potential effects. Commenters also note that since adaption is one of the likely impacts of climate change, it is irrational to exclude it from consideration when the goal is to evaluate the risks and harms in the real world in the future, not the risks and harms in the hypothetical scenario that result if you ignore adaptation.

According to commenters, the Administrator must consider both autonomous adaptation and anticipatory adaptation. They contend that literature on adaptation makes it clear there is a significant potential for adaptation, and that it can reduce the likelihood or severity of various effects, including health effects, and could even avert what might otherwise constitute endangerment. Commenters note that EPA considered the adaptation of species in nature, and it is arbitrary to not also consider adaptation by humans. Moreover, they argue that there is great

[15] The IPCC definition of adaptation: ''Adaptation to climate change takes place through adjustments to reduce vulnerability or enhance resilience in response to observed or expected changes in climate and associated extreme weather events. Adaptation occurs in physical, ecological and human systems. It involves changes in social and environmental processes, perceptions of climate risk, practices and functions to reduce potential damages or to realize new opportunities.'' The IPCC defines autonomous adaptation as ''Adaptation that does not constitute a conscious response to climatic stimuli but is triggered by ecological changes in natural systems and by market or welfare changes in human systems.''

certainty that adaptation will occur, and thus EPA is required to address it and make projections. They recommend that EPA look to historic responses to changes in conditions as an analogue in making projections, recognizing that life in the United States is likely to be quite different 50 or 100 years from now, irrespective of climate change.

Commenters argue that adaption needs to be considered because it is central to the statutory requirements governing the endangerment inquiry. EPA is charged to determine the type and extent of harms that are likely to occur, and they argue that this can not rationally be considered without considering adaptation. Since some degree of adaptation is likely to occur, they continue that such a projection of future actual conditions requires consideration of adaption to evaluate whether the future conditions amount to endangerment from the air pollution.

According to commenters, the issue therefore is focused on human and societal adaptation, which can come in a wide variety of forms, ranging from changes in personal behavioral patterns to expenditures of resources to change infrastructure, such as building and maintaining barriers to protect against sea level rise.

With regard to mitigation, commenters argue that EPA should consider mitigation strategies and their potential to alleviate harm from greenhouse gas emissions. They contend that it is unreasonable for EPA to assume that society will not undertake mitigation.

Section 202(a) of the CAA reflects the basic approach of many CAA sections—the threshold inquiry is whether the endangerment and cause or contribute criteria are satisfied, and only if they are met do the criteria for regulatory action go into effect. This reflects the basic separation of two different decisions—is this a health and welfare problem that should be addressed, and if so what are the appropriate mechanisms to address it? There is a division between identifying the health and welfare problem associated with the air pollution, and identifying the mechanisms used to address or solve the problem.

In evaluating endangerment, EPA is determining whether the risks to health and welfare from the air pollution amount to endangerment. As commenters recognize, that calls for evaluating and projecting the nature and types of risks from the air pollution, including the probability or likelihood of the occurrence of an impact and the degree of adversity (or benefit) of such an impact. This issue focuses on how EPA makes such an evaluation in determining endangerment—does EPA look at the risks assuming no planned adaptation and/or mitigation, although EPA projects some degree is likely to occur, or does EPA look at the risks remaining after some projection of adaptation and/or mitigation?

These two approaches reflect different views of the core question EPA is trying to answer. The first approach most clearly focuses on just the air pollution and its impacts, and aims to separate this from the human and societal responses that may or should be taken in response to the risks from the air pollution. By its nature, this separation means this approach may not reflect the actual conditions in the real world in the future, because adaptation and/or mitigation may occur and change the risks. For example, adaptation would not change the atmospheric concentrations, or the likelihood or probability of various impacts occurring (*e.g.*, it would not change the degree of sea level rise), but adaptation has the potential to reduce the adversity of the effects that do occur from these impacts. Mitigation could reduce the atmospheric concentrations that would otherwise occur, having the potential to reduce the likelihood or probability of various impacts occurring. Under this approach, the evaluation of risk is focused on the risk if we do not address the problem. It does not answer the question of how much risk we project will remain after we do address the problem, through either adaptation or mitigation or some combination of the two.

The second approach, suggested by commenters, would call for EPA to project into the future adaptation and/or mitigation, and the effect of these measures in reducing the risks to health or welfare from the air pollution. Commenters argue this will better reflect likely real world conditions, and therefore is needed to allow for an appropriate determination of whether EPA should, at this time, make an affirmative endangerment finding. However, this approach would not separate the air pollution and its impacts from the human and societal responses to the air pollution. It would intentionally and inextricably intertwine them. It would inexorably change the focus from how serious is the air pollution problem we need to address to how good a job are people and society likely to do in addressing or solving the problem. In addition it would dramatically increase the complexity of the issues before EPA.

The context for this endangerment finding is a time span of several decades into the future. It involves a wide variety of differing health and welfare effects, and almost every sector in our society. This somewhat unique context tends to amplify the differences between the two different approaches. It also means that it is hard to cleanly implement either approach. For example, it is hard under the first approach to clearly separate impacts with and without adaption, given the nature of the scientific studies and information before us. Under the second approach it would be extremely hard to make a reasoned projection of human and societal adaptation and mitigation responses, because these are basically not scientific or technical judgments, but are largely political judgments for society or individual personal judgments.

However, the context for this endangerment finding does not change the fact that at their core the two different approaches are aimed at answering different questions. The first approach is focused on answering the question of what are the risks to public health and welfare from the air pollution if we do not take action to address it. The second approach is focused on answering the question of how much risk will remain assuming some projection of how people and society will respond.

EPA believes that it is appropriate and reasonable to interpret CAA section 202(a) as calling for the first approach. The structure of CAA section 202(a) and the various other similar provisions indicate an intention by Congress to separate the question of what is the problem we need to address from the question of what is the appropriate way to address it. The first approach is clearly more consistent with this statutory structure. The amount of reduction in risk that might be achieved through adaptation and/or mitigation is closely related to the way to address a problem, and is not focused on what is the problem that needs to be addressed. It helps gauge the likelihood of success in addressing a problem, and how good a job society may do in reducing risk; it is not at all as useful in determining the severity of the problem that needs to be addressed.

The endangerment issue at its core is a decision on whether there is a risk to health and welfare that needs to be addressed, and the second approach would tend to indicate that the more likely a society is to solve a problem, the less likely there is a problem that needs to be addressed. This would mask the issue and provide a directionally wrong signal. Assume two different situations, both presenting the same serious risks to public health or welfare without consideration of adaptation or mitigation. The more successful society is projected to be in solving the serious problem in the future would mean the less likely we would be to make an endangerment finding at the inception identifying it as a problem that needs to be addressed. This is much less consistent with the logic embodied in CAA section 202(a), which separates the issue of whether there is a problem from the issue of what can be done to successfully address it.

In addition, the second approach would dramatically increase the complexity of the issues to resolve, and would do this by bringing in issues that are not the subject of the kind of scientific or technical judgments that Congress envisioned for the endangerment test. The legislative history indicates Congress was focused on issues of science and medicine, including issues at the frontiers of these fields. It referred to data, research resources, science and medicine, chemistry, biology, and statistics. There is no indication Congress envisioned exercising judgment on the very different types of issues involved in projecting the political actions likely to be taken by various local, State, and Federal governments, or judgments on the business or other decisions that are likely to be made by companies or other organizations, or the changes in personal behavior that may be occasioned by the adverse impacts of air pollution. The second approach would take EPA far away from the kind of judgments Congress envisioned for the endangerment test.

D. Geographic Scope of Impacts

It is the Administrator's view that the primary focus of the vulnerability, risk, and impact assessment is the United States. As described in Section IV of these Findings, the Administrator gives some consideration to climate change effects in world regions outside of the United States. Given the global nature of climate change, she has also examined potential impacts in other regions of the world. Greenhouse gases, once emitted, become well mixed in the atmosphere, meaning U.S. emissions can affect not only the U.S. population and environment, but other regions of the world as well. Likewise, emissions in other countries can affect the United States. Furthermore, impacts in other regions of the world may have consequences that in turn raise humanitarian, trade, and national security concerns for the United States.

Commenters argue that EPA does not have the authority to consider international effects. They contend that the burden is on EPA is to show endangerment based on impacts in the United States. They note that EPA proposed this approach, which is the only relevant issue for EPA. The purpose of CAA section 202(a), as the stated purpose of the CAA, commenters note, is to protect the quality of the nation's air resources and to protect the health and welfare of the U.S. population. Thus, they continue, international public health and welfare are not listed or stated, and are not encompassed by these provisions. Moreover, they argue that Congress addressed international impacts expressly in two other provisions of the CAA. They note that under CAA section 115, EPA considers emissions of pollutants that cause or contribute to air pollution that is reasonably anticipated to endanger public health or welfare in a foreign country, and that CAA section 179B addresses emissions of air pollutants in foreign countries that interfere with attainment of a National Ambient Air Quality Standards (NAAQS) in the United States. Because Congress intentionally addressed international impacts in those provision, commenters argue that the absence of this direction in CAA section 202(a) means that EPA is not to consider international effects when assessing endangerment under this provision.

Commenters fail to recognize that EPA's consideration of international effects is directed at evaluating their impact on the public health and welfare of the U.S. population. EPA is not considering international effects to determine whether the health and welfare of the public in a foreign country is endangered. Instead, EPA's consideration of international effects for purposes of determining endangerment is limited to how those international effects impact the health and welfare of the U.S. population.

The Administrator looked first at impacts in the United States itself, and determined that these impacts are reasonably anticipated to endanger the public health and the welfare of the U.S. population. That remains the Administrator's position, and by itself supports her determination of endangerment. The Administrator also considered the effects of global climate change outside the borders of the United States and evaluated them to determine whether these international effects impact the U.S. population, and if so whether it impacts the U.S. population in a manner that supports or does not support endangerment to the health and welfare of the U.S. public. She is not evaluating international effects to determine whether populations in a foreign country are endangered. The Administrator is looking at international effects solely for the purpose of evaluating their effects on the U.S. population.

For example, the U.S. population can be impacted by effects in other countries. These international effects can impact U.S. economic, trade, and humanitarian and national security interests. These would be potential effects on the U.S. population, brought about by the effects of climate change occurring outside the United States. It is fully reasonable and rational to expect that events occurring outside our borders can affect the U.S. population.

Thus, commenters misunderstand the role that international effects played in the proposal. The Administrator is not evaluating the impact of international effects on populations outside the United States; she is considering what impact these international effects could have on the U.S. population. That is fully consistent with the CAA's stated purpose of protecting the health and welfare of this nation's population.

E. Temporal Scope of Impacts

An additional parameter of the endangerment analysis is the timeframe. The Administrator's view is that the timeframe over which vulnerabilities, risks, and impacts are considered should be consistent with the timeframe over which greenhouse gases, once emitted, have an effect on climate. Thus the relevant time frame is decades to centuries for the primary greenhouse gases of concern. Therefore, in addition to reviewing recent observations, the underlying science upon which the Administrator is basing her findings generally considers the next several decades—the time period out to around 2100, and for certain impacts, the time period beyond 2100. How the accumulation of atmospheric greenhouse gases and resultant climate change may affect current and future generations is discussed in section IV in these Findings. By current generations we mean a near-term time frame of approximately the next 10 to 20 years; by future generations we mean a longer-term time frame extending beyond that. Some public comments were received that questioned making an endangerment finding based on current conditions, while others questioned EPA's ability to make an endangerment finding based on future projected conditions. Some of these comments are likewise addressed in Section IV in these Findings; and all comments on these temporal issues are addressed in the Response to Comments document.

F. Impacts of Potential Future Regulations and Processes That Generate Greenhouse Gas Emissions

This action is a stand-alone set of findings regarding endangerment and cause or contribute for greenhouse gases under CAA section 202(a), and does not contain any regulatory requirements. Therefore, this action does not attempt to assess the impacts of any future regulation. Although EPA would evaluate any future proposed regulation, many commenters argue that such a regulatory analysis should be part of the endangerment analysis.

Numerous commenters argue that EPA must fully consider the adverse and beneficial impacts of regulation together with the impacts of inaction, and describe this balancing as ''risk-risk analysis,'' ''health-health analysis,'' and most predominantly ''risk tradeoff analysis.'' Commenters argue that EPA's final endangerment finding would be arbitrary unless EPA undertakes this type of risk trade-off analysis.

Commenters specifically argue that EPA must consider the economic impact of regulation, including the Prevention of Significant Deterioration (PSD) permitting program for major stationary sources because it is triggered by a CAA section 202(a) standard, when assessing whether there is endangerment to public welfare. In other words, they argue that the Administrator should determine if finding endangerment and regulating greenhouse gases under the CAA would be worse for public health and welfare than not regulating. Commenters also argue that the reference to ''public'' health or welfare in CAA section 202, as well as the fact that impacts on the economy should be considered impacts to welfare, especially requires EPA to consider the full range of possible impacts of regulation. Commenters provide various predictions regarding how regulating greenhouse gases under the CAA more broadly will impact the public, industry, states the overall economy, and thus, they conclude, public health and welfare. Examples of commenters' predictions include potential adverse impacts on (1) the housing industry and the availability of affordable housing, (2) jobs and income due to industry moving overseas, (3) the agriculture industry and its ability to provide affordable food, and (4) the nation's energy supply. They also cite to the letter from the Office of Management and Budget provided with the ANPR, as well as interagency comments on the draft Proposed Findings, in support of their argument.

At least one commenter argues that EPA fails to discuss the public health or welfare benefits of the processes that *produce* the emissions. The commenter contends that for purposes of CAA section 202(a), this process would be the combustion of gasoline or other transportation fuel in new motor vehicles, and that for purposes of other CAA provisions with similar endangerment finding triggers, the processes would be the combustion of fossil fuel for electric generation and other activities. The commenter continues that EPA's decision to limit its analysis to the perceived detrimental aspects of emissions after they enter the atmosphere—as opposed to the possible positive aspects of emissions because of the processes that create the emissions—is based on EPA's overly narrow interpretation of both the meaning of the term ''emission'' in CAA section 202(a) (and therefore in other endangerment finding provisions) and the intent of these provisions. The commenter states that logically, it makes little sense to limit the definition of the term ''emission'' to only the ''air pollutants'' that are emitted. The commenter concludes that when EPA assesses whether the emission of greenhouse gases endanger public health and welfare, EPA must assess the dangers and benefits on both sides of the point where the emissions occur: in the atmosphere where the emissions lodge and, on the other side of the emitting stack or structure, in the processes that create the emissions. Otherwise, EPA will not be able to accurately assess whether the fact that society emits greenhouse gases is a benefit or a detriment. The commenter states that because greenhouse gas emissions, particularly carbon dioxide emissions, are so closely tied with all facets of modern life, a finding that greenhouse gas emissions endanger public health and welfare is akin to saying that modern life endangers public health or welfare. The commenter states that simply cannot be true because the lack of industrial activity that causes greenhouse gas emissions would pose other, almost certainly more serious health and welfare consequences.

Finally, some commenters argue that the impact of regulating under CAA section 202(a) supports making a final, negative endangerment finding. These commenters contend that the incredible costs associated with using the inflexible regulatory structure of the CAA will harm public health and welfare, and therefore EPA should exercise its discretion and find that greenhouse gases do not endanger public health and welfare because once EPA makes an endangerment finding under CAA section 202(a), it will be forced to regulate greenhouse gases under a number of other sections of the CAA, resulting in regulatory chaos.

At their core, these comments are not about whether commenters believe greenhouse gases may reasonably be anticipated to endanger public health or welfare, but rather about commenters' dissatisfaction with the decisions that Congress made regarding *the response* to any endangerment finding that EPA makes under CAA section 202(a). These comments do not discuss the science of greenhouse gases or climate change, or the impacts of climate change on public health or welfare. Instead they muddle the rather straightforward scientific judgment about whether there may be endangerment by throwing the potential impact of responding to the danger into the initial question. To use an analogy, the question of whether the cure is worse than the illness is different than the question of whether there is an illness in the first place. The question of whether there is endangerment is like the question of whether there is an illness. Once one knows there is an illness, then the next question is what to do, if anything, in response to that illness.

What these comments object to is that Congress has already made some decisions about next steps after a finding of endangerment, and commenters are displeased with the results. But if this is the case, commenters should take up their concerns with Congress, not EPA. EPA's charge is to issue new motor vehicle standards under CAA section 202(a) applicable to emissions of air pollutants that cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare. It is not to find that there is no endangerment in order to avoid issuing those standards, and dealing with any additional regulatory impact.

Indeed, commenters' argument would insert policy considerations into the endangerment decision, an approach already rejected by the Supreme Court. First, as discussed in Section I.B of these Findings, in *Massachusetts* v. *EPA*, the court clearly indicated that the Administrator's decision must be a ''scientific judgment.'' 549 U.S. at 534. She must base her decision about endangerment on the science, and not on policy considerations about the repercussions or impact of such a finding.

Second, in considering whether the CAA allowed for economic considerations to play a role in the promulgation of the NAAQS, the

Supreme Court rejected arguments that because many more factors than air pollution might affect public health, EPA should consider compliance costs that produce health losses in setting the NAAQS. *Whitman* v. *ATA*, 531 U.S. at 457, 466 (2001). To be sure, the language in CAA section 109(b) applicable to the setting of a NAAQS is different than that in CAA section 202(a) regarding endangerment. But the concepts are similar—the NAAQS are about setting standards at a level requisite to protect public health (with an adequate margin of safety) and public welfare, and endangerment is about whether the current or projected future levels may reasonably be anticipated to endanger public health or welfare. In other words, both decisions essentially are based on assessing the harm associated with a certain level of air pollution.

Given this similarity in purpose, as well as the Court's instructions in *Massachusetts* v. *EPA* that the Administrator should base her decision on the science, EPA reasonably interprets the statutory endangerment language to be analogous to setting the NAAQS. Therefore, it is reasonable to interpret the endangerment test as not requiring the consideration of the impacts of implementing the statute in the event of an endangerment finding as part of the endangerment finding itself.[16]

Moreover, EPA does not believe that the impact of regulation under the CAA as a whole, let alone that which will result from this particular endangerment finding, will lead to the panoply of adverse consequences that commenters predict. EPA has the ability to fashion a reasonable and common-sense approach to address greenhouse gas emissions and climate change. The Administrator thinks that EPA has and will continue to take a measured approach to address greenhouse gas emissions. For example, the Agency's recent Mandatory Greenhouse Gas Reporting Rule focuses on only the largest sources of greenhouse gases in order to reduce the burden on smaller facilities.[17]

We also note that commenters' approach also is another version of the argument that EPA must consider adaptation and mitigation in the endangerment determination. Just as EPA should consider whether mitigation would *reduce* endangerment, commenters argue we should consider whether mitigation would *increase* endangerment. But as discussed previously, EPA disagrees and believes its approach better achieves the goals of the statute.

Finally, EPA simply disagrees with the commenter who argues that because we are better off now than before the industrial revolution, greenhouse gases cannot be found to endanger public health or welfare. As the DC Circuit noted in the *Ethyl* decision, ''[m]an's ability to alter his environment has developed far more rapidly than his ability to foresee with certainty the effects of his alterations.'' See *Ethyl Corp.,* 541 F.2d at 6. The fact that we as a society are better off now than 100 years ago, and that processes that produce greenhouse gases are a large part of this improvement, does not mean that those processes do not have unintended adverse impacts. It also was entirely reasonable for EPA to look at ''emissions'' as the pollution once it is emitted from the source into the air, and not also as the process that generates the pollution. Indeed, the definition of ''air pollutant'' talks in terms of substances ''emitted into or otherwise enter[ing] the ambient air'' (CAA section 302(g)). It is entirely appropriate for EPA to consider only the substance being emitted as the air pollution or air pollutant.

IV. The Administrator's Finding That Greenhouse Gases Endanger Public Health and Welfare

The Administrator finds that elevated concentrations of greenhouse gases in the atmosphere may reasonably be anticipated to endanger the public health and to endanger the public welfare of current and future generations. The Administrator is making this finding specifically with regard to six key directly-emitted, long-lived and well-mixed greenhouse gases: Carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The Administrator is making this judgment based on both current observations and projected risks and impacts into the future. Furthermore, the Administrator is basing this finding on impacts of climate change within the United States. However, the Administrator finds that when she considers the impacts on the U.S. population of risks and impacts occurring in other world regions, the case for endangerment to public health and welfare is only strengthened.

A. The Air Pollution Consists of Six Key Greenhouse Gases

The Administrator must define the scope and nature of the relevant air pollution for the endangerment finding under CAA section 202(a). In this final action, the Administrator finds that the air pollution is the combined mix of six key directly-emitted, long-lived and well-mixed greenhouse gases (henceforth ''well-mixed greenhouse gases''), which together, constitute the root cause of human-induced climate change and the resulting impacts on public health and welfare. These six greenhouse gases are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

EPA received public comments on this definition of air pollution from the Proposed Findings, and summarizes responses to some of those key comments below; fuller responses to public comments can be found in EPA's Response to Comments document, Volume 9. The Administrator acknowledges that other anthropogenic climate forcers also play a role in climate change. Many public comments either supported or opposed inclusion of other substances in addition to the six greenhouse gases for the definition of air pollution. EPA's responses to those comments are also summarized below, and in volume 9 of the Response to Comments document.

The Administrator explained her rationale for defining air pollution under CAA section 202(a) as the combined mix of the six greenhouse gases in the Proposed Findings. After review of the public comments, the Administrator is using the same definition of the air pollution in the

[16] Indeed, some persons may argue that due to the similarities between setting a NAAQS and making an endangerment finding, EPA cannot consider the impacts of implementation of the statute.

[17] Note that it is EPA's current position that these Final Findings do not make well-mixed greenhouse gases ''subject to regulation'' for purposes of the CAA's Prevention of Significant Deterioration (PSD) and title V programs. *See, e.g.*, memorandum entitled ''EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program'' (Dec. 18, 2008). While EPA is reconsidering this memorandum and is seeking public comment on the issues raised in it generally, including whether a final endangerment finding should trigger PSD, the effectiveness of the positions provided in the memorandum was not stayed pending that reconsideration. Prevention of Significant Deterioration (PSD): Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program, 74 FR 515135, 51543–44 (Oct. 7, 2009). In addition, EPA has proposed new temporary thresholds for greenhouse gas emissions that define when PSD and title V permits are required for new or existing facilities. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (74 FR 55292, October 27, 2009). The proposed thresholds would ''tailor'' the permit programs to limit which facilities would be required to obtain PSD and title V permits. As noted in the preamble for the tailoring rule proposal, EPA also intends to evaluate ways to streamline the process for identifying GHG emissions control requirements and issuing permits. See the Response to Comments Document, Volume 11, and the Tailoring Rule, for more information.

final finding, for the following reasons: (1) These six greenhouse gas share common properties regarding their climate effects; (2) these six greenhouse gases have been estimated to be the primary cause of human-induced climate change, are the best understood drivers of climate change, and are expected to remain the key driver of future climate change; (3) these six greenhouse gases are the common focus of climate change science research and policy analyses and discussions; (4) using the combined mix of these gases as the definition (versus an individual gas-by-gas approach) is consistent with the science, because risks and impacts associated with greenhouse gas-induced climate change are not assessed on an individual gas approach; and (5) using the combined mix of these gases is consistent with past EPA practice, where separate substances from different sources, but with common properties, may be treated as a class (*e.g.,* oxides of nitrogen).

1. Common Physical Properties of the Six Greenhouse Gases

The common physical properties relevant to the climate change problem shared by the six greenhouse gases include the fact that they are long-lived in the atmosphere. ''Long-lived'' is used here to mean that the gas has a lifetime in the atmosphere sufficient to become globally well mixed throughout the entire atmosphere, which requires a minimum atmospheric lifetime of about one year.[18] Thus, this definition of air pollution is global in nature because the greenhouse gas emissions emitted from the United States (or from any other region of the world) become globally well mixed, such that it would not be meaningful to define the air pollution as the greenhouse gas concentrations over the United States as somehow being distinct from the greenhouse gas concentrations over other regions of the world.

It is also well established that each of these gases can exert a warming effect on the climate by trapping in heat that would otherwise escape to space. These six gases are directly emitted as greenhouse gases rather than forming as a greenhouse gas in the atmosphere after emission of a pre-cursor gas. Given these properties, the magnitude of the warming effect of each of these gases is generally better understood than other climate forcing agents that do not share these same properties (addressed in more detail below). The ozone-depleting substances that include chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HFCs) also share the same physical attributes discussed here, but for reasons discussed throughout the remainder of this section are not being included in the Administrator's definition of air pollution for this finding.

2. Evidence That the Six Greenhouse Gases Are the Primary Driver of Current and Projected Climate Change

a. Key Observations Driven Primarily by the Six Greenhouse Gases

The latest assessment of the USGCRP, as summarized in EPA's TSD, confirms the evidence presented in the Proposed Findings that current atmospheric greenhouse gas concentrations are now at elevated and essentially unprecedented levels as a result of both historic and current anthropogenic emissions. The global atmospheric carbon dioxide concentration has increased about 38 percent from pre-industrial levels to 2009, and almost all of the increase is due to anthropogenic emissions. The global atmospheric concentration of methane has increased by 149 percent since pre-industrial levels (through 2007); and the nitrous oxide concentration has increased 23 percent (through 2007). The observed concentration increase in these gases can also be attributed primarily to anthropogenic emissions. The industrial fluorinated gases have relatively low concentrations, but these concentrations have also been increasing and are almost entirely anthropogenic in origin.

Historic data show that current atmospheric concentrations of the two most important directly emitted, long-lived greenhouse gases (carbon dioxide and methane) are well above the natural range of atmospheric concentrations compared to at least the last 650,000 years. Atmospheric greenhouse gas concentrations have been increasing because anthropogenic emissions are outpacing the rate at which greenhouse gases are removed from the atmosphere by natural processes over timescales of decades to centuries. It also remains clear that these high atmospheric concentrations of greenhouse gases are the unambiguous result of human activities.

Together the six well-mixed greenhouse gases constitute the largest anthropogenic driver of climate change.[19] Of the total anthropogenic heating effect caused by the accumulation of the six well-mixed greenhouse gases plus other warming agents (that do not meet all of the Administrator's criteria that pertain to the six greenhouse gases) since pre-industrial times, the combined heating effect of the six well-mixed greenhouses is responsible for roughly 75 percent, and it is expected that this share may grow larger over time, as discussed below.

Warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global average sea level. Global mean surface temperatures have risen by 0.74 °C (1.3 °F) (±0.18 °C) over the last 100 years. Eight of the 10 warmest years on record have occurred since 2001. Global mean surface temperature was higher during the last few decades of the 20th century than during any comparable period during the preceding four centuries.

The global surface temperature record relies on three major global temperature datasets, developed by NOAA, NASA, and the United Kingdom's Hadley Center. All three show an unambiguous warming trend over the last 100 years, with the greatest warming occurring over the past 30 years.[20] Furthermore, all three datasets show that eight of the 10 warmest years on record have occurred since 2001; that the 10 warmest years have all occurred in the past 12 years; and that the 20 warmest years have all occurred since 1981. Though most of the warmest years on record have occurred in the last decade in all available datasets, the rate of warming has, for a short time in the

[18] The IPCC also refers to these six GHGs as long-lived. Methane has an atmospheric lifetime of roughly a decade. One of the most commonly used hydrofluorocarbons (HFC–134a) has a lifetime of 14 years. Nitrous oxide has a lifetime of 114 years; sulfur hexafluoride over 3,000 years; and some PFCs up to 10,000 to 50,000 years. Carbon dioxide in the atmosphere is sometimes approximated as having a lifetime of roughly 100 years, but for a given amount of carbon dioxide emitted a better description is that some fraction of the atmospheric increase in concentration is quickly absorbed by the oceans and terrestrial vegetation, some fraction of the atmospheric increase will only slowly decrease over a number of years, and a small portion of the increase will remain for many centuries or more.

[19] As summarized in EPA's TSD, the global average net effect of the increase in atmospheric greenhouse gas concentrations, plus other human activities (*e.g.,* land use change and aerosol emissions), on the global energy balance since 1750 has been one of warming. This total net heating effect, referred to as forcing, is estimated to be +1.6 (+0.6 to +2.4) Watts per square meter (W/m^2), with much of the range surrounding this estimate due to uncertainties about the cooling and warming effects of aerosols. The combined radiative forcing due to the cumulative (*i.e.,* 1750 to 2005) increase in atmospheric concentrations of CO_2, CH_4, and N_2O is estimated to be +2.30 (+2.07 to +2.53) W/m^2. The rate of increase in positive radiative forcing due to these three GHGs during the industrial era is very likely to have been unprecedented in more than 10,000 years.

[20] *See* section 4 of the TSD for more detailed information about the three global temperature datasets.

Hadley Center record, slowed. However, the NOAA and NASA trends do not show the same marked slowdown for the 1999–2008 period. Year-to-year fluctuations in natural weather and climate patterns can produce a period that does not follow the long-term trend. Thus, each year may not necessarily be warmer than every year before it, though the long-term warming trend continues.[21]

The scientific evidence is compelling that elevated concentrations of heat-trapping greenhouse gases are the root cause of recently observed climate change. The IPCC conclusion from 2007 has been re-confirmed by the June 2009 USGCRP assessment that most of the observed increase in global average temperatures since the mid-20th century is very likely[22] due to the observed increase in anthropogenic greenhouse gas concentrations. Climate model simulations suggest natural forcing alone (*e.g.,* changes in solar irradiance) cannot explain the observed warming.

The attribution of observed climate change to anthropogenic activities is based on multiple lines of evidence. The first line of evidence arises from our basic physical understanding of the effects of changing concentrations of greenhouse gases, natural factors, and other human impacts on the climate system. The second line of evidence arises from indirect, historical estimates of past climate changes that suggest that the changes in global surface temperature over the last several decades are unusual.[23] The third line of evidence arises from the use of computer-based climate models to simulate the likely patterns of response of the climate system to different forcing mechanisms (both natural and anthropogenic).

The claim that natural internal variability or known natural external forcings can explain most (more than half) of the observed global warming of the past 50 years is inconsistent with the vast majority of the scientific literature, which has been synthesized in several assessment reports. Based on analyses of widespread temperature increases throughout the climate system and changes in other climate variables, the IPCC has reached the following conclusions about external climate forcing: ''It is extremely unlikely (<5 percent) that the global pattern of warming during the past half century can be explained without external forcing, and very unlikely that it is due to known natural external causes alone'' (Hegerl *et al.,* 2007). With respect to internal variability, the IPCC reports the following: ''The simultaneous increase in energy content of all the major components of the climate system as well as the magnitude and pattern of warming within and across the different components supports the conclusion that the cause of the [20th century] warming is extremely unlikely (<5 percent) to be the result of internal processes'' (Hegerl *et al.,* 2007). As noted in the TSD, the observed warming can only be reproduced with models that contain both natural and anthropogenic forcings, and the warming of the past half century has taken place at a time when known natural forcing factors alone (solar activity and volcanoes) would likely have produced cooling, not warming.

United States temperatures also warmed during the 20th and into the 21st century; temperatures are now approximately 0.7 °C (1.3 °F) warmer than at the start of the 20th century, with an increased rate of warming over the past 30 years. Both the IPCC and CCSP reports attributed recent North American warming to elevated greenhouse gas concentrations. The CCSP (2008g) report finds that for North America, ''more than half of this warming [for the period 1951–2006] is likely the result of human-caused greenhouse gas forcing of climate change.''

Observations show that changes are occurring in the amount, intensity, frequency, and type of precipitation. Over the contiguous United States, total annual precipitation increased by 6.1 percent from 1901–2008. It is likely that there have been increases in the number of heavy precipitation events within many land regions, even in those where there has been a reduction in total precipitation amount, consistent with a warming climate.

There is strong evidence that global sea level gradually rose in the 20th century and is currently rising at an increased rate. It is very likely that the response to anthropogenic forcing contributed to sea level rise during the latter half of the 20th century. It is not clear whether the increasing rate of sea level rise is a reflection of short-term variability or an increase in the longer-term trend. Nearly all of the Atlantic Ocean shows sea level rise during the last 50 years with the rate of rise reaching a maximum (over 2 mm per year) in a band along the U.S. east coast running east-northeast.

Satellite data since 1979 show that annual average Arctic sea ice extent has shrunk by 4.1 percent per decade. The size and speed of recent Arctic summer sea ice loss is highly anomalous relative to the previous few thousands of years.

Widespread changes in extreme temperatures have been observed in the last 50 years across all world regions including the United States. Cold days, cold nights, and frost have become less frequent, while hot days, hot nights, and heat waves have become more frequent.

Observational evidence from all continents and most oceans shows that many natural systems are being affected by regional climate changes, particularly temperature increases. However, directly attributing specific regional changes in climate to emissions of greenhouse gases from human activities is difficult, especially for precipitation.

Ocean carbon dioxide uptake has lowered the average ocean pH (increased the acidity) level by approximately 0.1 since 1750. Consequences for marine ecosystems may include reduced calcification by shell-forming organisms, and in the longer term, the dissolution of carbonate sediments.

Observations show that climate change is currently affecting U.S. physical and biological systems in significant ways. The consistency of these observed changes in physical and biological systems and the observed significant warming likely cannot be explained entirely due to natural variability or other confounding non-climate factors.

b. Key Projections Based Primarily on Future Scenarios of the Six Greenhouse Gases

There continues to be no reason to expect that, without substantial and near-term efforts to significantly reduce emissions, atmospheric levels of greenhouse gases will not continue to climb, and thus lead to ever greater rates of climate change. Given the long atmospheric lifetime of the six greenhouse gases, which range from roughly a decade to centuries, future atmospheric greenhouse gas

[21] Karl T. *et al.,* (2009).

[22] The IPCC Fourth Assessment Report uses specific terminology to convey likelihood and confidence. Likelihood refers to a probability that the statement is correct or that something will occur. ''Virtually certain'' conveys greater than 99 percent probability of occurrence; ''very likely'' 90 to 99 percent; ''likely'' 66 to 90 percent. IPCC assigns confidence levels as to the correctness of a statement. ''Very high confidence'' conveys at least 9 out of 10 chance of being correct; ''high confidence'' about 8 out of 10 chance; ''medium confidence'' about 5 out of 10 chance. The USGCRP uses the same or similar terminology in its reports. See also Box 1.2 of the TSD. Throughout this document, this terminology is used in conjunction with statements from the IPCC and USGCRP reports to convey the same meaning that those reports intended. In instances where a word such as ''likely'' may appear outside the context of a specific IPCC or USGCRP statement, it is not meant to necessarily convey the same quantitative meaning as the IPCC terminology.

[23] Karl T. *et al.* (2009).

concentrations for the remainder of this century and beyond will be influenced not only by future emissions but indeed by present-day and near-term emissions. Consideration of future plausible scenarios, and how our current greenhouse gas emissions essentially commit present and future generations to cope with an altered atmosphere and climate, reinforces the Administrator's judgment that it is appropriate to define the combination of the six key greenhouse gases as the air pollution.

Most future scenarios that assume no explicit greenhouse gas mitigation actions (beyond those already enacted) project increasing global greenhouse gas emissions over the century, which in turn result in climbing greenhouse gas concentrations. Under the range of future emission scenarios evaluated by the assessment literature, carbon dioxide is expected to remain the dominant anthropogenic greenhouse gas, and thus driver of climate change, over the course of the 21st century. In fact, carbon dioxide is projected to be the largest contributor to total radiative forcing in all periods and the radiative forcing associated with carbon dioxide is projected to be the fastest growing. For the year 2030, projections of the six greenhouse gases show an increase of 25 to 90 percent compared with 2000 emissions. Concentrations of carbon dioxide and the other well-mixed gases increase even for those scenarios where annual emissions toward the end of the century are assumed to be lower than current annual emissions. The radiative forcing associated with the non-carbon dioxide well-mixed greenhouse gases is still important and increasing over time. Emissions of the ozone-depleting substances are projected to continue decreasing due to the phase-out schedule under the Montreal Protocol on Substances that Deplete the Ozone Layer. Considerable uncertainties surround the estimates and future projections of anthropogenic aerosols; future atmospheric concentrations of aerosols, and thus their respective heating or cooling effects, will depend much more on assumptions about future emissions because of their short atmospheric lifetimes compared to the six well-mixed greenhouse gases.

Future warming over the course of the 21st century, even under scenarios of low emissions growth, is very likely to be greater than observed warming over the past century. According to climate model simulations summarized by the IPCC, through about 2030, the global warming rate is affected little by the choice of different future emission scenarios. By the end of the century, projected average global warming (compared to average temperature around 1990) varies significantly depending on emissions scenario and climate sensitivity assumptions, ranging from 1.8 to 4.0 °C (3.2 to 7.2 °F), with an uncertainty range of 1.1 to 6.4 °C (2.0 to 11.5 °F).

All of the United States is very likely to warm during this century, and most areas of the United States are expected to warm by more than the global average. The largest warming is projected to occur in winter over northern parts of Alaska. In western, central and eastern regions of North America, the projected warming has less seasonal variation and is not as large, especially near the coast, consistent with less warming over the oceans.

3. The Six Greenhouse Gases Are Currently the Common Focus of the Climate Change Science and Policy Communities

The well-mixed greenhouse gases are currently the common focus of climate science and policy analyses and discussions. For example, the United Nations Framework Convention on Climate Change (UNFCCC), signed and ratified by the United States in 1992, requires its signatories to ''develop, periodically update, publish and make available * * * national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies * * *'' [24] [25] To date, the focus of UNFCCC actions and discussions has been on the six greenhouse gases that are the same focus of these Findings.

Because of these common properties, it has also become common practice to compare these gases on a carbon dioxide equivalent basis, based on each gas's warming effect relative to carbon dioxide (the designated reference gas) over a specified timeframe. For example, both the annual *Inventory of U.S. Greenhouse Gases and Sinks* published by EPA and the recently finalized EPA Mandatory Greenhouse Gas Reporting Rule (74 FR 56260), use the carbon dioxide equivalent metric to sum and compare these gases, and thus accept the common climate-relevant properties of these gases for their treatment as a group. This is also common practice internationally as the UNFCCC reporting guidelines for developed countries, and the Clean Development Mechanism procedures for developing countries both require the use of global warming potentials published by the IPCC to convert the six greenhouse gases into their respective carbon dioxide equivalent units.

4. Defining Air Pollution as the Aggregate Group of Six Greenhouse Gases Is Consistent With Evaluation of Risks and Impacts Due to Human-Induced Climate Change

Because the well-mixed greenhouse gases are collectively the primary driver of current and projected human-induced climate change, all current and future risks due to human-induced climate change—whether these risks are associated with increases in temperature, changes in precipitation, a rise in sea levels, changes in the frequency and intensity of weather events, or more directly with the elevated greenhouse gas concentrations themselves—can be associated with this definition of air pollution.

5. Defining the Air Pollution as the Aggregate Group of Six Greenhouse Gases Is Consistent With Past EPA Practice

Treating the air pollution as the aggregate of the well-mixed greenhouse gases is consistent with other provisions of the CAA and previous EPA practice under the CAA, where separate emissions from different sources but with common properties may be treated as a class (*e.g.,* particulate matter (PM)). This approach addresses the total, cumulative effect that the elevated concentrations of the six well-mixed greenhouse gases have on climate, and thus on different elements of health, society and the environment.[24]

EPA treats, for example, PM as a common class of air pollution; PM is a complex mixture of extremely small particles and liquid droplets. Particle pollution is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles.

6. Other Climate Forcers Not Being Included in the Definition of Air Pollution for This Finding

Though the well-mixed greenhouse gases that make up the definition of air pollution for purposes of making the endangerment decision under CAA section 202(a) constitute the primary

[24] Due to the cumulative purpose of the statutory language, even if the Administrator were to look at the atmospheric concentration of each greenhouse gas individually, she would still consider the impact of the concentration of a single greenhouse gas in combination with that caused by the other greenhouse gases.

[25] The range of uncertainty in the current magnitude of black carbon's climate forcing effect is evidenced by the ranges presented by the IPCC Fourth Assessment Report (2007) and the more recent study by Ramanathan, V. and Carmichael, G. (2008) Global and regional climate changes due to black carbon. Nature Geoscience, 1(4): 221–227.

driver of human-induced climate change, there are other substances emitted from human activities that contribute to climate change and deserve careful attention, but are not being included in the air pollution definition for this particular action. These substances are discussed immediately below.

a. Black Carbon

Several commenters request that black carbon be included in the definition of air pollution because of its warming effect on the climate. Black carbon is not a greenhouse gas, rather, it is an aerosol particle that results from the incomplete combustion of carbon contained in fossil fuels and biomass, and remains in the atmosphere for only about a week. Unlike any of the greenhouse gases being addressed by this action, black carbon is a component of particulate matter (PM), where PM is a criteria air pollutant under section 108 of the CAA. The extent to which black carbon makes up total PM varies by emission source, where, for example, diesel vehicle PM emissions contain a higher fraction of black carbon compared to most other PM emission sources. Black carbon causes a warming effect primarily by absorbing incoming and reflected sunlight (whereas greenhouse gases cause warming by trapping outgoing, infrared heat), and by darkening bright surfaces such as snow and ice, which reduces reflectivity. This latter effect, in particular, has been raising concerns about the role black carbon may be playing in observed warming and ice melt in the Arctic.

As stated in the April 2009 Proposed Findings, there remain some significant scientific uncertainties about black carbon's total climate effect,[25] as well as concerns about how to treat the short-lived black carbon emissions alongside the long-lived, well-mixed greenhouse gases in a common framework (*e.g.,* what are the appropriate metrics to compare the warming and/or climate effects of the different substances, given that, unlike greenhouse gases, the magnitude of aerosol effects can vary immensely with location and season of emissions). Nevertheless, the Administrator recognizes that black carbon is an important climate forcing agent and takes very seriously the emerging science on black carbon's contribution to global climate change in general and the high rates of observed climate change in the Arctic in particular. As noted in the Proposed Findings, EPA has various pending petitions under the CAA calling on the Agency to make an endangerment finding and regulate black carbon emissions.

b. Other Climate Forcers

There are other climate forcers that play a role in human-induced climate change that were mentioned in the Proposed Findings, and were the subject of some public comments. These include the stratospheric ozone-depleting substances, nitrogen trifluoride (NF_3), water vapor, and tropospheric ozone.

As mentioned above, the ozone-depleting substances (CFCs and HCFCs) do share the same physical, climate-relevant attributes as the six well-mixed greenhouse gases; however, emissions of these substances are playing a diminishing role in human-induced climate change. They are being controlled and phased out under the Montreal Protocol on Substances that Deplete the Ozone Layer. Because of this, the major scientific assessment reports such as those from IPCC focus primarily on the same six well-mixed greenhouse gases included in the definition of air pollution in these Findings. It is also worth noting that the UNFCCC, to which the United States is a signatory, addresses ''all greenhouse gases not controlled by the Montreal Protocol.'' [26] One commenter noted that because the Montreal Protocol controls production and consumption of ozone-depleting substances, but not existing banks of the substances, that CFCs should be included in the definition of air pollution in this finding, which might, in turn, create some future action under the CAA to address the banks of ozone-depleting substances as a climate issue. However, the primary criteria for defining the air pollution in this finding is the focus on the core of the climate change problem, and concerns over future actions to control depletion of stratospheric ozone are separate from and not central to the air pollution causing climate change.

Nitrogen trifluoride also shares the same climate-relevant attributes as the six well-mixed greenhouse gases, and it is also included in EPA's Mandatory Greenhouse Gas Reporting Rule (FR 74 56260). However, the Administrator is maintaining the reasoning laid out in the Proposed Findings to not include NF_3 in the definition of air pollution for this finding because the overall magnitude of its forcing effect on climate is not yet well quantified. EPA will continue to track the science on NF_3.

A number of public comments question the exclusion of water vapor from the definition of air pollution because it is the most important greenhouse gas responsible for the natural, background greenhouse effect. The Administrator's reasoning for excluding water vapor, was described in the Proposed Findings and is summarized here with additional information in Volume 10 of the Response to Comments document. First, climate change is being driven by the buildup in the atmosphere of greenhouse gases. The direct emissions primarily responsible for this are the six well-mixed greenhouse gases. Direct anthropogenic emissions of water vapor, in general, have a negligible effect and are thus not considered a primary driver of human-induced climate change. EPA plans to further evaluate the issues of emissions of water that are implicated in the formation of contrails and also changes in water vapor due to local irrigation. At this time, however, the findings of the IPCC state that the total forcing from these sources is small and that the level of understanding is low.

Water produced as a byproduct of combustion at low altitudes has a negligible contribution to climate change. The residence time of water vapor is very short (days) and the water content of the air in the long term is a function of temperature and partial pressure, with emissions playing no role. Additionally, the radiative forcing of a given mass of water at low altitudes is much less than the same mass of carbon dioxide. Water produced at higher altitudes could potentially have a larger impact. The IPCC estimated the contribution of changes in stratospheric water vapor due to methane and other sources, as well as high altitude contributions from contrails, but concluded that both contributions were small, with a low level of understanding. The report also addressed anthropogenic contributions to water vapor arising from large scale irrigation, but assigned it a very low level of understanding, and suggested that the cooling from evaporation might outweigh the warming from its small radiative contribution.

Increases in tropospheric ozone concentrations have exerted a significant anthropogenic warming effect since pre-industrial times. However, as explained in the Proposed Findings, tropospheric ozone is not a long-lived, well-mixed greenhouse gas, and it is not directly emitted. Rather it forms in the atmosphere from emissions of pre-cursor gases. There is increasing attention in climate change research and the policy community about the extent to which further reductions in tropospheric ozone levels may help

[26] UNFCCC, Art. 4.1(b).

slow down climate change in the near term. The Administrator views this issue seriously but maintains that tropospheric ozone is sufficiently different such that it deserves an evaluation and treatment separate from this finding.

7. Summary of Key Comments on Definition of Air Pollution

a. It Is Reasonable for the Administrator To Define the Air Pollution as Global Concentrations of the Well-Mixed Greenhouse Gases

Many commenters argue that EPA does not have the authority to establish domestic rights and obligations based on environmental conditions that are largely attributed to foreign nations and entities that are outside the jurisdiction of EPA under the CAA. They contend that in this case, the bulk of emissions that would lead to mandatory emissions controls under the CAA would not and could not be regulated under the CAA. They state that CAA requirements cannot be enforced against foreign sources of air pollution, and likewise domestic obligations under the CAA cannot be caused by foreign emissions that are outside the United States. The commenters argue that EPA committed procedural error by not addressing this legal issue of authority in the proposal.

Commenters cite no statutory text or judicial authority for this argument, and instead rely entirely on an analogy to the issues concerning the exercise of extra-territorial jurisdiction. The text of CAA section 202(a), however, does not support this claim. Nothing in CAA section 202(a) limits the term air pollution to those air pollution matters that are caused solely or in large part by domestic emissions. The only issue under CAA section 202(a) is whether the air pollution is reasonably anticipated to endanger, and whether emissions from one domestic source category—new motor vehicles—cause or contribute to this air pollution. Commenters would read into this an additional cause or contribute test—whether foreign sources cause or contribute to the air pollution in such a way that the air pollution is largely attributable to the foreign emissions, or the bulk of emissions causing the air pollution are from foreign sources. There is no such provision in CAA section 202(a). Congress was explicit about the contribution test it imposed, and the only source that is relevant for purposes of contribution is new motor vehicles. Commenters suggest an ill-defined criterion that is not in the statute.

In addition, as discussed in Section II of these Findings, Congress intentionally meant the agency to judge the air pollution endangerment criteria based on the ''cumulative impact of all sources of a pollutant,'' and not an incremental look at just the endangerment from a subset of sources. Commenters' arguments appear to lead to this result. Under the commenters' approach, in those cases where the bulk of emissions which form the air pollution come from foreign sources, EPA apparently would have no authority to make an endangerment finding. Logically, EPA would be left with the option of identifying and evaluating the air pollution attributable to domestic sources alone, and determining whether that narrowly defined form of air pollution endangers public health or welfare. This is the kind of unworkable, incremental approach that was rejected by the court in *Ethyl* and by Congress in the 1977 amendments adopting this provision.

The analogy to extra-territorial jurisdiction is also not appropriate. The endangerment finding itself does not exercise jurisdiction over any source, domestic or foreign. It is a judgment that is a precondition for exercising regulatory authority. Under CAA section 202(a), any exercise of regulatory authority following from this endangerment finding would be for new motor vehicles either manufactured in the United States or imported into the United States. There would be no extra-territorial exercise of jurisdiction. The core issues for endangerment focus on impacts inside the United States, not outside the United States. In addition, the contribution finding is based solely on the contribution from new motor vehicles built in or imported to the United States. The core judgments that need to be made under CAA section 202(a) are all focused on actions and impacts inside the United States. This does not raise any concerns about an extra-territorial exercise of jurisdiction. The basis for the endangerment and contribution findings is fully consistent with the principles underlying the desire to avoid exercises of extra-territorial jurisdiction. Any limitations on the ability to exercise control over foreign sources of emissions does not, however, call into question the authority under CAA section 202 to exercise control over domestic sources of emissions based on their contribution to an air pollution problem that is judged to endanger public health or welfare based on impacts occurring in the United States or otherwise affecting the United States and its citizens.

In essence, commenters are concerned about the effectiveness of the domestic control strategies that can be adopted to address a global air pollution problem that is caused only in part by domestic sources of emissions. While that is a quite valid and important policy concern, it does not translate into a legal limitation on EPA's authority to make an endangerment finding. Neither the text nor the legislative history of CAA section 202(a) support such an interpretation and Congress explicitly separated the decision on endangerment from the decision on what controls are required or appropriate once an affirmative endangerment finding has been made. The effectiveness of the resulting regulatory controls is not a relevant factor to determining endangerment.

EPA also committed no procedural flaw as argued by commenters. The proposal fully explored the interpretation of endangerment and cause or contribution under CAA section 202(a), and was very clear that EPA was considering air pollution to mean the elevated global concentration of greenhouse gases in the atmosphere, recognizing that these atmospheric concentrations were the result of world wide emissions, not just or even largely U.S. emissions. The separation of the effectiveness of the control strategy from the endangerment criteria, and the need to consider the cumulative impact of all sources in evaluating endangerment was clearly discussed. Commenters received fair notice of EPA's proposal and the basis for it.

Similarly, some commenters argue that EPA's proposal defines air pollution as global air pollution, but EPA is limited to evaluating domestic air only; in other words that EPA may only regulate domestic emissions with localized effects. They argue this limitation derives from the purpose of the CAA—to enhance the quality of the Nation's air resources, recognizing that air pollution prevention and control focus on the sources of the emissions, and are the primary responsibility of States and local governments. Therefore, commenters continue, that ''air pollution'' has to be air pollution that originates domestically and is to be addressed only at the domestic source. Sections 115 and 179B of the CAA, as discussed below, reflect this intention as well. The result, they conclude, is that ''air pollution'' as used in CAA section 202(a), includes only pollution that originates domestically, where the effects occur locally. They argue EPA has improperly circumvented this by a ''local-global-local'' analysis that injects global air pollution into the middle of the endangerment test.

The statutory arguments made by the commenters attempt to read an unrealistic limitation into the general provisions discussed. The issues are similar in nature to those raised by the commenters arguing that EPA has no authority to establish domestic rights and obligations based on environmental conditions that are largely attributable to emissions from foreign nations and entities that are outside the jurisdiction of EPA under the CAA. In both cases, the question is whether EPA has authority to make an endangerment finding when the air pollution of concern is a relatively homogenous atmospheric concentration of greenhouse gases. According to the commenters, although this global pool includes the air over the United States, and leads to impacts in the United States and on the U.S. population, Congress prohibited EPA from addressing this air pollution problem because of its global aspects.

The text of the CAA does not specifically address this, as the term air pollution is not defined. EPA interprets this term as including the air pollution problem involved in this case—elevated atmospheric concentration of greenhouse gases that occur in the air above the United States as well as across the globe, and where this pool of global gases leads to impacts in the United States and on the U.S. population. This is fully consistent with the statutory provisions discussed by commenters. This approach seeks to protect the Nation's air resources, as clearly the Nation's air resources are an integral part of this global pool. The Nation's air resources by definition are not an isolated atmosphere that only contains molecules emitted within the United States, or an atmosphere that bears no relationship to the rest of the globe's atmosphere. There is no such real world body of air. Protecting the Nation's resources of clean air means to protect the air in the real world, not an artificial construct of ''air'' that ignores the many situations where the air over our borders includes compounds and pollutants emitted outside our borders, and in this case to ignore the fact that the air over our borders will by definition have elevated concentrations of greenhouse gases only when the air around the globe also has such concentrations. The suggested narrow view of ''air pollution'' does not further the protection of the Nation's air resources, but instead attempts to limit such protection by defining these resources in a scientifically artificial way that does not comport with how the air in the atmosphere is formed or changes over time, how it relates to and interacts with air around the globe, and how the result of this can affect the U.S. population.

The approach suggested by commenters fails to provide an actual definition for EPA to follow—for example, would U.S. or domestic ''air pollution'' be limited to only those air concentrations composed of molecules that originated in the United States? Is there a degree of external gases or compounds that could be allowed? Would it ignore the interaction and relationship between the air over the U.S. borders and the air around the rest of the globe? The latter approach appears to be the one suggested by commenters. Commenters' approach presumably would call for EPA to only consider the effects that derive solely from the air over our borders, and to ignore any effects that occur within the United States that are caused by air around the globe. However the air over the United States will by definition affect climate change only in circumstances where the air around the world is also doing so. The impacts of the air over the United States cannot be assessed separately from the impacts from the global pool, as they occur together and work together to affect the climate. Ignoring the real world nature of the Nation's air resources, in the manner presumably suggested by the commenters, would involve the kind of unworkable, incremental, and artificially isolating approach that was rejected by the court in *Ethyl* and by Congress in 1977. Congress intended EPA to interpret this provision by looking at air pollutants and air pollution problems in a broad manner, not narrowly, to evaluate problems within their broader context and not to attempt to isolate matters in an artificial way that fails to account for the real world context that lead to health and welfare impacts on the public. Commenters' suggested interpretation fails to implement this intention of Congress.

Commenters in various places refer to the control of the pollution, and the need for it to be aimed at local sources. That is addressed in the standard setting portion of CAA section 202(a), as in other similar provisions. The endangerment provision does not address how the air pollution problem should be addressed—who should be regulated and how they should be regulated. The endangerment provision addresses a different issue—is there an air pollution problem that should be addressed? In that context, EPA rejects the artificially narrow interpretation suggested by the commenters, and believes its broader interpretation in this case is reasonable and consistent with the intention of Congress.

b. Consideration of Greenhouse Gases as Air Pollution Given Their Impact Is Through Climate Rather Than Direct Toxic Effects

A number of commenters argue that carbon dioxide and the other greenhouse gases should not be defined as the air pollution because these gases do not cause direct human health effects, such as through inhalation. Responses to such comments are summarized in Section IV.B.1 of these Findings in the discussion of the public health and welfare nature of the endangerment finding.

c. The Administrator's Reliance on the Global Temperature Data Is a Reasonable Indicator of Human-Induced Climate Change

We received many comments suggesting global temperatures have stopped warming. The commenters base this conclusion on temperature trends over only the last decade. While there have not been strong trends over the last seven to ten years in global surface temperature or lower troposphere temperatures measured by satellites, this pause in warming should not be interpreted as a sign that the Earth is cooling or that the science supporting continued warming is in error. Year-to-year variability in natural weather and climate patterns make it impossible to draw any conclusions about whether the climate system is warming or cooling from such a limited analysis. Historical data indicate short-term trends in long-term time series occasionally run counter to the overall trend. All three major global surface temperature records show a continuation of long-term warming. Over the last century, the global average temperature has warmed at the rate of about 0.13 °F (0.072 °C) per decade in all three records. Over the last 30 years, the global average surface temperature has warmed by about 0.30 °F (0.17 °C) per decade. Eight of the 10 warmest years on record have occurred since 2001 and the 20 warmest years have all occurred since 1981. Satellite measurements of the troposphere also indicate warming over the last 30 years at a rate of 0.20 to 0.27 °F (0.11 °C to 0.15 °C) per decade. Please see the relevant volume of the Response to Comments document for more detailed responses.

Some commenters indicate the global surface temperature records are biased by urbanization, poor siting of instruments, observation methods, and other factors. Our review of the literature suggests that these biases have in many cases been corrected for, are largely random where they remain, and therefore cancel out over large regions. Furthermore, we note that though the three global surface temperature records use differing techniques to analyze much of the same data, they produce almost the same results, increasing our confidence in their legitimacy. The assessment literature has concluded that warming of the climate system is unequivocal. The warming trend that is evident in all of the temperature records is confirmed by other independent observations, such as the melting of Arctic sea ice, the retreat of mountain glaciers on every continent, reductions in the extent of snow cover, earlier blooming of plants in the spring, and increased melting of the Greenland and Antarctic ice sheets. Please see the relevant volume of the Response to Comments document for more detailed responses.

A number of commenters argue that the warmth of the late 20th century is not unusual relative to the past 1,000 years. They maintain temperatures were comparably warm during the Medieval Warm Period (MWP) centered around 1000 A.D. We agree there was a Medieval Warm Period in many regions but find the evidence is insufficient to assess whether it was globally coherent. Our review of the available evidence suggests that Northern Hemisphere temperatures in the MWP were probably between 0.1 °C and 0.2 °C below the 1961–1990 mean and significantly below the level shown by instrumental data after 1980. However, we note significant uncertainty in the temperature record prior to 1600 A.D. Please see the relevant volume of the Response to Comments document for more detailed responses.

d. Ability To Attribute Observed Climate Change to Anthropogenic, Well-Mixed Greenhouse Gases

Many commenters question the link between observed temperatures and anthropogenic greenhouse gas emissions. They suggest internal variability of the climate system and natural forcings explain observed temperature trends and that anthropogenic greenhouse gases play, at most, a minor role. However, the attribution of most of the recent warming to anthropogenic activities is based on multiple lines of evidence. The first line of evidence arises from our basic physical understanding of the effects of changing concentrations of greenhouse gases, natural factors, and other human impacts on the climate system. Greenhouse gas concentrations have indisputably increased and their radiative properties are well established. The second line of evidence arises from indirect, historical estimates of past climate changes that suggest that the changes in global surface temperature over the last several decades are unusual. The third line of evidence arises from the use of computer-based climate models to simulate the likely patterns of response of the climate system to different forcing mechanisms (both natural and anthropogenic). These models are unable to replicate the observed warming unless anthropogenic emissions of greenhouse gases are included in the simulations. Natural forcing alone cannot explain the observed warming. In fact, the assessment literature [27] indicates the sum of solar and volcanic forcing in the past half century would likely have produced cooling, not warming. Please see the relevant volume of the Response to Comments for more detailed responses.

B. The Air Pollution Is Reasonably Anticipated To Endanger Both Public Health and Welfare

The Administrator finds that the elevated atmospheric concentrations of the well-mixed greenhouse gases may reasonably be anticipated to endanger the public health and welfare of current and future generations. This section describes the major pieces of scientific evidence supporting the Administrator's endangerment finding, discusses both the public health and welfare nature of the endangerment finding, and addresses a number of key issues the Administrator considered when evaluating the state of the science as well as key public comments on the Proposed Findings. Additional detail can be found in the TSD and the Response to Comments document.

As described in Section II of these Findings, the endangerment test under CAA section 202(a) does not require the Administrator to identify a bright line, quantitative threshold above which a positive endangerment finding can be made. The statutory language explicitly calls upon the Administrator to use her judgment. This section describes the general approach used by the Administrator in reaching the judgment that a positive endangerment finding should be made, as well as the specific rationale for finding that the greenhouse gas air pollution may reasonably be anticipated to endanger both public health and welfare.

First, the Administrator finds the scientific evidence linking human emissions and resulting elevated atmospheric concentrations of the six well-mixed greenhouse gases to observed global and regional temperature increases and other climate changes to be sufficiently robust and compelling. This evidence is briefly explained in more detail in Section V of these Findings. The Administrator recognizes that the climate change associated with elevated atmospheric concentrations of carbon dioxide and the other well-mixed greenhouse gases have the potential to affect essentially every aspect of human health, society and the natural environment. The Administrator is therefore not limiting her consideration of potential risks and impacts associated with human emissions of greenhouse gases to any one particular element of human health, sector of the economy, region of the country, or to any one particular aspect of the natural environment. Rather, the Administrator is basing her finding on the total weight of scientific evidence, and what the science has to say regarding the nature and potential magnitude of the risks and impacts across all climate-sensitive elements of public health and welfare, now and projected out into the foreseeable future.

The Administrator has considered the state of the science on how human emissions and the resulting elevated atmospheric concentrations of well-mixed greenhouse gases may affect each of the major risk categories, *i.e.,* those that are described in the TSD, which include human health, air quality, food production and agriculture, forestry, water resources, sea level rise and coastal areas, the energy sector, infrastructure and settlements, and ecosystems and wildlife. The Administrator understands that the nature and potential severity of impacts can vary across these different elements of public health and welfare, and that they can vary by region, as well as over time.

The Administrator is therefore aware that, because human-induced climate change has the potential to be far-reaching and multi-dimensional, not all

[27] Solomon, S., D. Qin, M. Manning, R.B. Alley, T. Berntsen, N.L. Bindoff, Z. Chen, A. Chidthaisong, J.M. Gregory, G.C. Hegerl, M. Heimann, B. Hewitson, B.J. Hoskins, F. Joos, J. Jouzel, V. Kattsov, U. Lohmann, T. Matsuno, M. Molina, N. Nicholls, J. Overpeck, G. Raga, V. Ramaswamy, J. Ren, M. Rusticucci, R. Somerville, T.F. Stocker, P. Whetton, R.A. Wood and D. Wratt (2007) Technical Summary. In: *Climate Change 2007: The Physical Science Basis.* Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor, and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Karl, T. et al. (2009).

risks and potential impacts can be characterized with a uniform level of quantification or understanding, nor can they be characterized with uniform metrics. Given this variety in not only the nature and potential magnitude of risks and impacts, but also in our ability to characterize, quantify and project into the future such impacts, the Administrator must use her judgment to weigh the threat in each of the risk categories, weigh the potential benefits where relevant, and ultimately judge whether these risks and benefits, when viewed in total, are judged to be endangerment to public health and/or welfare.

This has a number of implications for the Administrator's approach in assessing the nature and magnitude of risk and impacts across each of the risk categories. First, the Administrator has not established a specific threshold metric for each category of risk and impacts. Also, the Administrator is not necessarily placing the greatest weight on those risks and impacts which have been the subject of the most study or quantification.

Part of the variation in risks and impacts is the fact that climbing atmospheric concentrations of greenhouse gases and associated temperature increases can bring about some potential benefits to public health and welfare in addition to adverse risks. The current understanding of any potential benefits associated with human-induced climate change is described in the TSD and is taken into consideration here. The potential for both adverse and beneficial effects are considered, as well as the relative magnitude of such effects, to the extent that the relative magnitudes can be quantified or characterized. Furthermore, given the multiple ways in which the buildup of atmospheric greenhouse gases can cause effects (*e.g.,* via elevated carbon dioxide concentrations, via temperature increases, via precipitation increases, via sea level rise, and via changes in extreme events), these multiple pathways are considered. For example, elevated carbon dioxide concentrations may be beneficial to crop yields, but changes in temperature and precipitation may be adverse and must also be considered. Likewise, modest temperature increases may have some public health benefits as well as harms, and other pathways such as changes in air quality and extreme events must also be considered.

The Administrator has balanced and weighed the varying risks and effects for each sector. She has judged whether there is a pattern across the sector that supports or does not support an endangerment finding, and if so whether the support is of more or less weight. In cases where there is both a potential for benefits and risks of harm, the Administrator has balanced these factors by determining whether there appears to be any directional trend in the overall evidence that would support placing more weight on one than the other, taking into consideration all that is known about the likelihood of the various risks and effects and their seriousness. In all of these cases, the judgment is largely qualitative in nature, and is not reducible to precise metrics or quantification.

Regarding the timeframe for the endangerment test, it is the Administrator's view that both current and future conditions must be considered. The Administrator is thus taking the view that the endangerment period of analysis extend from the current time to the next several decades, and in some cases to the end of this century. This consideration is also consistent with the timeframes used in the underlying scientific assessments. The future timeframe under consideration is consistent with the atmospheric lifetime and climate effects of the six well-mixed greenhouse gases, and also with our ability to make reasonable and plausible projections of future conditions.

The Administrator acknowledges that some aspects of climate change science and the projected impacts are more certain than others. Our state of knowledge is strongest for recently observed, large-scale changes. Uncertainty tends to increase in characterizing changes at smaller (regional) scales relative to large (global) scales. Uncertainty also increases as the temporal scales move away from present, either backward, but more importantly forward in time. Nonetheless, the current state of knowledge of observed and past climate changes and their causes enables projections of plausible future changes under different scenarios of anthropogenic forcing for a range of spatial and temporal scales.

In some cases, where the level of sensitivity to climate of a particular sector has been extensively studied, future impacts can be quantified whereas in other instances only a qualitative description of a directional change, if that, may be possible. The inherent uncertainty in the direction, magnitude, and/or rate of certain future climate change impacts opens up the possibility that some changes could be more or less severe than expected, and the possibility of unanticipated outcomes. In some cases, low probability, high impact outcomes (*i.e.,* known unknowns) are possibilities but cannot be explicitly assessed.

1. The Air Pollution Is Reasonably Anticipated To Endanger Public Health

The Administrator finds that the well-mixed greenhouse gas air pollution is reasonably anticipated to endanger public health, for both current and future generations. The Administrator finds that the public health of current generations is endangered and that the threat to public health for both current and future generations will likely mount over time as greenhouse gases continue to accumulate in the atmosphere and result in ever greater rates of climate change.

After review of public comments, the Administrator continues to believe that climate change can increase the risk of morbidity and mortality and that these public health impacts can and should be considered when determining endangerment to public health under CAA section 202(a). As described in Section IV.B.1 of these Findings, the Administrator is not limited to only considering whether there are any direct health effects such as respiratory or toxic effects associated with exposure to greenhouse gases.

In making this public health finding, the Administrator considered direct temperature effects, air quality effects, the potential for changes in vector-borne diseases, and the potential for changes in the severity and frequency of extreme weather events. In addition, the Administrator considered whether and how susceptible populations may be particularly at risk. The current state of science on these effects from the major assessment reports is described in greater detail in the TSD, and our responses to public comments are provided in the Response to Comments Documents.

a. Direct Temperature Effects

It has been estimated that unusually hot days and heat waves are becoming more frequent, and that unusually cold days are becoming less frequent, as noted above. Heat is already the leading cause of weather-related deaths in the United States. In the future, severe heat waves are projected to intensify in magnitude and duration over the portions of the United States where these events already occur. Heat waves are associated with marked short-term increases in mortality. Hot temperatures have also been associated with increased morbidity. The projected warming is therefore projected to increase heat related mortality and morbidity, especially among the elderly, young and frail. The populations most sensitive to hot temperatures are older adults, the chronically sick, the very young, city-dwellers, those taking medications that disrupt thermoregulation, the mentally ill, those lacking access to air conditioning, those working or playing outdoors, and socially isolated persons. As warming increases over time, these adverse effects would be expected to increase as the serious heat events become more serious.

Increases in temperature are also expected to lead to some reduction in the risk of death related to extreme cold. Cold waves continue to pose health risks in northern latitudes in temperature regions where very low temperatures can be reached in a few hours and extend over long periods. Globally, the IPCC projects reduced human mortality from cold exposure through 2100. It is not clear whether reduced mortality in the United States from cold would be greater or less than increased heat-related mortality in the United States due to climate change. However, there is a risk that projections of cold-related deaths, and the potential for decreasing their numbers due to warmer winters, can be overestimated unless they take into account the effects of season and influenza, which is not strongly associated with monthly winter temperature. In addition, the latest USGCRP report refers to a study that analyzed daily mortality and weather data in 50 U.S. cities from 1989 to 2000 and found that, on average, cold snaps in the United States increased death rates by 1.6 percent, while heat waves triggered a 5.7 percent increase in death rates. The study concludes that increases in heat-related mortality due to global warming in the United States are unlikely to be compensated for by decreases in cold-related mortality.

b. Air Quality Effects

Increases in regional ozone pollution relative to ozone levels without climate change are expected due to higher temperatures and weaker circulation in the United States relative to air quality levels without climate change. Climate change is expected to increase regional ozone pollution, with associated risks in respiratory illnesses and premature death. In addition to human health effects, tropospheric ozone has significant adverse effects on crop yields, pasture and forest growth, and species composition. The directional effect of climate change on ambient particulate matter levels remains less certain.

Climate change can affect ozone by modifying emissions of precursors, atmospheric chemistry, and transport and removal. There is now consistent evidence from models and observations that 21st century climate change will worsen summertime surface ozone in polluted regions of North America compared to a future with no climate change.

Modeling studies discussed in EPA's Interim Assessment[28] show that simulated climate change causes increases in summertime ozone concentrations over substantial regions of the country, though this was not uniform, and some areas showed little change or decreases, though the decreases tend to be less pronounced than the increases. For those regions that showed climate-induced increases, the increase in maximum daily 8-hour average ozone concentration, a key metric for regulating U.S. air quality, was in the range of 2 to 8 ppb, averaged over the summer season. The increases were substantially greater than this during the peak pollution episodes that tend to occur over a number of days each summer. The overall effect of climate change was projected to increase ozone levels, compared to what would occur without this climate change, over broad areas of the country, especially on the highest ozone days and in the largest metropolitan areas with the worst ozone problems. Ozone decreases are projected to be less pronounced, and generally to be limited to some regions of the country with smaller population.

c. Effects on Extreme Weather Events

In addition to the direct effects of temperature on heat- and cold-related mortality, the Administrator considers the potential for increased deaths, injuries, infectious diseases, and stress-related disorders and other adverse effects associated with social disruption and migration from more frequent extreme weather. The Administrator notes that the vulnerability to weather disasters depends on the attributes of the people at risk (including where they live, age, income, education, and disability) and on broader social and environmental factors (level of disaster preparedness, health sector responses, and environmental degradation). The IPCC finds the following with regard to extreme events and human health:

[28] U.S. EPA (2009) *Assessment of the Impacts of Global Change on Regional U.S. Air Quality: A Synthesis of Climate Change Impacts on Ground-Level Ozone*. An Interim Report of the U.S. EPA Global Change Research Program. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–07/094.

Increases in the frequency of heavy precipitation events are associated with increased risk of deaths and injuries as well as infectious, respiratory, and skin diseases. Floods are low-probability, high-impact events that can overwhelm physical infrastructure, human resilience, and social organization. Flood health impacts include deaths, injuries, infectious diseases, intoxications, and mental health problems.

Increases in tropical cyclone intensity are linked to increases in the risk of deaths, injuries, waterborne and food borne diseases, as well as post-traumatic stress disorders. Drowning by storm surge, heightened by rising sea levels and more intense storms (as projected by IPCC), is the major killer in coastal storms where there are large numbers of deaths. Flooding can cause health impacts including direct injuries as well as increased incidence of waterborne diseases due to pathogens such as *Cryptosporidium and Giardia.*

d. Effects on Climate-Sensitive Diseases and Aeroallergens

According to the assessment literature, there will likely be an increase in the spread of several food and water-borne pathogens among susceptible populations depending on the pathogens' survival, persistence, habitat range and transmission under changing climate and environmental conditions. Food borne diseases show some relationship with temperature, and the range of some zoonotic disease carriers such as the Lyme disease carrying tick may increase with temperature.

Climate change, including changes in carbon dioxide concentrations, could impact the production, distribution, dispersion and allergenicity of aeroallergens and the growth and distribution of weeds, grasses, and trees that produce them. These changes in aeroallergens and subsequent human exposures could affect the prevalence and severity of allergy symptoms. However, the scientific literature does not provide definitive data or conclusions on how climate change might impact aeroallergens and subsequently the prevalence of allergenic illnesses in the United States.

It has generally been observed that the presence of elevated carbon dioxide concentrations and temperatures stimulate plants to increase photosynthesis, biomass, water use efficiency, and reproductive effort. The IPCC concluded that pollens are likely to increase with elevated temperature and carbon dioxide.

e. Summary of the Administrator's Finding of Endangerment to Public Health

The Administrator has considered how elevated concentrations of the well-mixed greenhouse gases and associated climate change affect public health by evaluating the risks associated with changes in air quality, increases in temperatures, changes in extreme weather events, increases in food and water borne pathogens, and changes in aeroallergens. The evidence concerning adverse air quality impacts provides strong and clear support for an endangerment finding. Increases in ambient ozone are expected to occur over broad areas of the country, and they are expected to increase serious adverse health effects in large population areas that are and may continue to be in nonattainment. The evaluation of the potential risks associated with increases in ozone in attainment areas also supports such a finding.

The impact on mortality and morbidity associated with increases in average temperatures which increase the likelihood of heat waves also provides support for a public health endangerment finding. There are uncertainties over the net health impacts of a temperature increase due to decreases in cold-related mortality, but there is some recent evidence that suggests that the net impact on mortality is more likely to be adverse, in a context where heat is already the leading cause of weather-related deaths in the United States.

The evidence concerning how human-induced climate change may alter extreme weather events also clearly supports a finding of endangerment, given the serious adverse impacts that can result from such events and the increase in risk, even if small, of the occurrence and intensity of events such as hurricanes and floods. Additionally, public health is expected to be adversely affected by an increase in the severity of coastal storm events due to rising sea levels.

There is some evidence that elevated carbon dioxide concentrations and climate changes can lead to changes in aeroallergens that could increase the potential for allergenic illnesses. The evidence on pathogen borne disease vectors provides directional support for an endangerment finding. The Administrator acknowledges the many uncertainties in these areas. Although these adverse effects, provide some support for an endangerment finding, the Administrator is not placing primary weight on these factors.

Finally, the Administrator places weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to these climate-related health effects.

f. Key Comments on the Finding of Endangerment to Public Health

EPA received many comments on public health issues and the proposed finding of endangerment to public health.

i. EPA's Consideration of the Climate Impacts as Public Health Issues Is Reasonable

Several commenters argue that EPA may only consider the health effects from direct exposure to pollutants in determining whether a pollutant endangers public health. The commenters state that EPA's proposal acknowledges that there is no evidence that greenhouse gases directly cause health effects, citing 74 FR 18901. To support their claim that EPA can only consider health effects that result from direct exposure to a pollutant, commenters cite several sources, discussed below.

Clean Air Act and Legislative History. Several commenters argue that the text of the CAA and the legislative history of the 1977 amendments demonstrate that Congress intended public health effects to relate to risks from direct exposure to a pollutant. They also argue that by considering health effects that result from welfare effects, EPA was essentially combining the two categories into one, contrary to the statute and Congressional intent.

Commenters state that the CAA, including CAA section 202(a)(1), requires EPA to consider endangerment of public health separately from endangerment of public welfare. Commenters note that while the CAA does not provide a definition of public health, CAA section 302(h) addresses the meaning of ''welfare,'' which includes weather and climate. Thus, they argue, Congress has instructed that effects on weather and climate are to be considered as potentially endangering welfare—not human health. They continue that Congress surely knew that weather and climatic events such as flooding and heat waves could affect human health, but Congress nonetheless classified air pollutants' effects on weather and climate as effects on welfare.

Commenters also argue that the legislative history confirms that Congress intended for the definition of ''public health'' to only include the consequences of direct human exposure to ambient air pollutants. They note an early version of section 109(b) would have required only a single NAAQS standard to protect ''public health,'' with the protection of ''welfare'' being a co-benefit of the single standard. Commenters note that the proponents of this early bill explained, ''[i]n many cases, a level of protection of health would take care of the welfare situation'' Sen. Hearing, Subcommittee on Air and Water Pollution, Comm. On Public Works (Mar. 17, 1970) (statement of Dr. Middleton, Comm'r, Nat'l Air Pollution Control Admin., HEW), 1970 Leg. Hist. 1194. Commenters state that the Senate bill that ultimately passed rejected this combined standard, requiring separate national ambient air quality standards and national ambient air quality goals. Commenters contend that Congress intended that the national ambient air quality goals be set ''to protect the public health and welfare from any known or anticipated effects associated with'' air pollution, including the list of ''welfare'' effects currently found in CAA section 302(h), such as effects on water, vegetation, animals, wildlife, weather and climate. Commenters note the Senate Committee Report stated that the national ambient air quality *standards* were created to protect public health, while the national ambient air quality *goals* were intended to address broader issues because ''the Committee also recognizes that man's natural and man-made environment must be preserved and protected. Therefore, the bill provides for the setting of national ambient air quality goals at levels necessary to protect public health and welfare from any known or anticipated adverse effects of air pollution—including effects on soils, water, vegetation, man-made materials, animals, wildlife, visibility, climate, and economic values.'' Commenters argue this statement is clearly the source of the current definition of welfare effects in CAA section 302(h), which also includes ''personal comfort and well being.'' They argue the Senate bill contemplated the NAAQS would include only direct health effects, while the *goals* would encompass effects on both the public health and welfare. Commenters continue that considering both public health effects and welfare effects under a combined standard, as the Administrator attempts to do in the proposed endangerment finding, would resurrect the combined approach to NAAQS that the Senate emphatically rejected.

The commenters also cite language from the House Report in support of their view that Congress only intended that EPA consider direct health effects when assessing endangerment to public health: ''By the words 'cause or contribute to air pollution,' the committee intends to require the Administrator to consider all sources of the contaminant which contributes to air pollution and to consider all sources of exposure to the contaminant—food, water, air, etc.—in determining health risks'' 7 H.R. Rep. No. 95–294, at 49–50 (1977). Commenters also cite language in the Senate Report: ''Knowledge of the relationship between the exposure to many air pollution agents and acute and chronic health effects is sufficient to develop air quality criteria related to such effects'' S. Rep. No. 91–1196, at 7 (1970).

The specific issue here is whether an effect on human health that results from a change in climate should be considered when EPA determines whether the air pollution of well-mixed greenhouse gases is reasonably anticipated to endanger public health. In this case, the air pollution has an effect on climate. For example the air pollution raises surface, air, and water temperatures. Among the many effects that flow from this is the expectation that there will be an increase in the risk of mortality and morbidity associated with increased intensity of heat waves. In addition, there is an expectation that there will be an increase in levels of ambient ozone, leading to increased risk of morbidity and mortality from exposure to ozone. All of these are effects on human health, and all of them are associated with the effect on climate from elevated atmospheric concentrations of greenhouse gases. None of these human health effects are associated with direct exposure to greenhouse gases.

In the past, EPA has not had to resolve the issue presented here, as it has been clear whether the effects relate to public health or relate to public welfare, with no confusion over what category was at issue. In those cases EPA has routinely looked at what effect the air pollution has on people. If the effect on people is to their health, we have considered it an issue of public health. If the effect on people is to their interest in matters other than health, we have considered it public welfare.

For example, there are serious health risks associated with inhalation of ozone, and they have logically been considered as public health issues. Ambient levels of ozone have also raised the question of indirect health benefits through screening of harmful UVB rays. EPA has also considered this indirect health effect of ozone to be a public health issue.[29] Ozone pollution also affects people by impacting their interests in various vegetation through foliar damage to trees, reduced crop yield, adverse impacts on horticultural plants, and the like. EPA has consistently considered these issues when evaluating the public welfare based NAAQS standards under CAA section 109.

In all of these situations the use of the term ''public'' has focused EPA on how people are affected by the air pollution. If the effect on people is to their health then we have considered it a public health issue. If the effect on people is to their interest in matters other than health, then we have treated it as a public welfare issue.

The situation presented here is somewhat unique. The focus again is on the effect the air pollution has on people. Here the effect on people is to their health. However this effect flows from the change in climate and effects on climate are included in the definition of effects on welfare. That raises the issue of how to categorize the health effects—should we consider them when evaluating endangerment to public health? When we evaluate endangerment to public welfare? Or both?

The text of the CAA does not resolve this question. While Congress defined ''effects on welfare,'' it did not define either ''public health'' or ''public welfare''. In addition, the definition of ''effects on welfare'' does not clearly address how to categorize health effects that flow from effects on soils, water, crops, vegetation, weather, climate, or any of the other factors listed in CAA section 302(h). It is clear that effects on climate are an effect on welfare, but the definition does not address whether health impacts that are caused by these changes in climate are also effects on welfare. The health effects at issue are not themselves effects on soils, water, crops, vegetation, weather, or climate. They are instead effects on health. They derive from the effects on climate, but they are not themselves effects on climate or on anything else listed in CAA section 302(h). So the definition of effects on welfare does not address whether an effect on health, which is not itself listed in CAA section 302(h), is also an effect on welfare if it results from an effect on welfare. The text of the CAA also does not address the issue of direct and indirect health effects. Contrary to commenters' assertions, the legislative history does not address or resolve this issue.

In this context, EPA is interpreting the endangerment provision in CAA section 202(a) as meaning that the effects on peoples' health from changes to climate can and should be included in EPA's evaluation of whether the air pollution at issue endangers public health. EPA is not deciding whether these health effects also could or should be considered in evaluating endangerment to public welfare.

The stating of the issue makes the answer seem straightforward. If air pollution causes sickness or death, then these health effects should be considered when evaluating whether the air pollution endangers public health. The term public health is undefined, and by itself this is an eminently reasonable way to interpret it. This focuses on the actual effect on people, as compared to ignoring that and focusing on the pathway from the air pollution to the effect. The question then becomes whether there is a valid basis in the CAA to take the different approach suggested by commenters, an approach contrary to the common sense meaning of public health.

Notably, the term ''public welfare'' is undefined. While it clearly means something other than public health, there is no obvious indication whether Congress intended there to be a clear boundary between the two terms or whether there might be some overlap where some impacts could be considered both a public health and a public welfare impact. Neither the text nor the legislative history resolves this issue. Under either approach, EPA believes the proper interpretation is that these effects on health should be considered when evaluating endangerment to public health.

If we assume Congress intended that effects on public welfare could not include effects on public health and vice versa, then the effects at issue here should most reasonably be considered in the public health category. Indisputably they are health effects, and the plain meaning of the term public health would call for their inclusion in that term. The term public welfare is

[29] As discussed later, in the past EPA took the position that this kind of potential indirect beneficial impact on public health should not be considered when setting the primary health based NAAQS for ozone. This was not based on the view that it was not a potential public health impact, or that it was a public welfare impact instead of a public health impact. Instead EPA was interpreting the NAAQS standard setting provisions of section 109, and argued that they were intended to address only certain public health impacts, those that were adverse, and were not intended to address indirect, beneficial public health impacts. This interpretation of section 109 was rejected in *ATA* v. *EPA*, 175 F.3d 1027 (1999) *reh'g granted in part and denied in part*, 195 F.3d 4 (DC Cir. 1999). The court made it clear that the potential indirect beneficial impact of ambient ozone on public health from screening UVB rays needed to be considered when setting the NAAQS to protect public health.

undefined. If Congress intended that public welfare not include matters included in the public health category, then a reasonable interpretation of this undefined term would include those effects on welfare that impact people in ways other than impacting their health.

The definition of ''effects on welfare'' does not clearly address how to categorize health effects that flow from effects on water, soil, land, climate, or weather. As noted above, the definition does not address whether health impacts that are caused by these changes in climate are also ''effects on welfare.'' Certainly effects on health are not included in the list in CAA section 302(h). The lack of clarity in the definition of effects on welfare, combined with the lack of definition of public welfare, do not warrant interpreting the term public health differently from its straightforward and common sense meaning.

The inclusion of the phrase ''effects on * * * personal comfort and well-being'' as an effect on welfare supports this view. The term would logically mean something other than the different term public health. The term ''well-being'' is not defined, and generally has a broader and different connotation of positive physical, emotional, and mental status. The most straightforward meaning of this term, in a context where Congress used the different term public health in a wide variety of other provisions, would be to include effects on people that do not rise to the level of health effects, but otherwise impact their physical, emotional, and mental status. This gives full meaning to both terms.

The term well-being is a general term, and in isolation arguably could include health effects. However there is no textual basis to say it would include some health effects but not others, as argued by commenters. If sickness impacts your well-being, then it impacts your well-being whether it results directly or indirectly from the pollution in the air. Nothing in CAA section 302(h) limits the term well-being to indirect impacts on people, or to health effects that occur because of other welfare effects, such as climate change. It is listed as its own effect on welfare. Instead of interpreting well-being as including all health effects, or some health effects, the much more logical way to interpret this provision in the context of all of the other provisions of the CAA is to interpret it as meaning effects on people other than health effects.

Thus, if Congress intended to draw a strict line between the two categories of public health and public welfare, for purposes of determining endangerment under CAA section 202(a), then EPA believes that its interpretation is a reasonable and straightforward way to categorize the health effects at issue here. This gives weight to the common sense meaning of the term public health, where the terms public health and public welfare are undefined and the definition of effects on welfare is at best ambiguous on this issue.

In the alternative, if Congress did not intend any such bright line between these two categories and there could be an overlap, then it is also reasonable for EPA to include these health effects in its consideration of whether the air pollution endangers public health. Neither approach condenses or conflates the two different terms. Under either approach EPA's interpretation, as demonstrated in this rulemaking, would still consider numerous and varied effects from climate change as indisputable impacts on public welfare and not impacts on public health. In addition, this interpretation will not change the fact that in almost all cases impacts on public health would not also be considered impacts on public welfare.

Prior EPA actions. Several commenters argue that EPA's decision to include health impacts that occur because of climate change is inconsistent with its past approach, which has been to treat indirect health effects as welfare effects. Commenters contend that in the latest Criteria Document for ozone EPA listed tropospheric ozone's effects on UVB-induced human diseases, as well as its effects on climate change, as welfare effects, even though the agency acknowledged significant health effects such as sunburn and skin cancer. Commenters also argue that EPA listed ''risks to human health'' from toxins released by algal blooms due to excess nitrogen as ''ecological and other welfare effects'' in the recent Criteria Document for oxides of nitrogen and sulfur. Finally, commenters argue that EPA's proposed action was contrary to the Agency decision to list new municipal solid waste landfills as a source category under CAA section 111. Commenters state that EPA listed climate change as a welfare effect in that action, (citing 56 FR 24469).

The Agency's recent approach regarding UVB-induced health effects is consistent with the endangerment findings, and demonstrates that the Agency considers indirect effects on human health as public health issues rather than public welfare issues. While the ozone Criteria Document may have placed the discussion of UV–B related health effects among chapters on welfare effects, in evaluating the evidence presented in the Criteria Document for purposes of preparing the policy assessment document, EPA staff clearly viewed UVB-induced effects as human health effects that were relevant in determining the public health based primary NAAQS for ozone, rather than welfare effects, regardless of which chapter in the Criteria Document described those effects. The evaluation of the UVB-related evidence is discussed with other human health effects evidence. The policy assessment document noted that Chapter 10 of the Criteria Document, ''provides a thorough analysis of the current understanding of the relationship between reducing tropospheric [ozone] concentrations and the potential impact these reductions might have on UV–B surface fluxes and *indirectly contributing to increased UV–B related health effects.'' See*, *Review of the National Ambient Air Quality Standards for Ozone: Policy Assessment of Scientific and Technical Information*, p 3–36 (January 2007) (emphasis added).

EPA repeated this view in the 2007 proposed ozone NAAQS rule. In presenting its evaluation of the human health evidence for purposes of setting the public health based primary NAAQS, EPA stated: ''This section also summarizes the uncertainty about the *potential indirect effects on public health* associated with changes due to increases in UV–B radiation exposure, such as UV–B radiation-related skin cancers, that may be associated with reductions in ambient levels of ground-level [ozone], as discussed in chapter 10 of the Criteria Document and chapter 3 of the Staff Paper.'' 72 FR 37818, 37827. *See* also, 72 FR 37837 (''* * * the Criteria Document also assesses the potential indirect effects related to the presence of [ozone] in the ambient air by considering the role of ground-level [ozone] in mediating human health effects that may be directly attributable to exposure to solar ultraviolet radiation (UV–B).'')

Thus, EPA's approach to UV–B related health effects clearly shows the Agency has treated indirect health effects not as welfare effects, as commenters suggest, but as human health effects that need to be evaluated when setting the public health based primary NAAQS. In this ozone NAAQS rulemaking, EPA did not draw a line between direct and indirect health effects for purposes of evaluating UV–B related health effects and the public health based primary NAAQS.

Similarly, the NO_X/SO_X criteria document does not establish a precedent that indirect human health effects are welfare effects. Toxic algal blooms themselves are a welfare effect, so it is not surprising a discussion of algal blooms appears in sections dealing with welfare effects. The more relevant question is how EPA evaluated information regarding human health risks resulting from algal blooms. In the case of the Criteria Document, the role of nitrogen in causing algal blooms was unclear. As a result, the Agency did not have occasion to evaluate any resulting human health effects and the Criteria Document does not support the view that EPA treats indirect health effects as anything other than a public health issue.

Finally, EPA disagrees that its action here is at odds with the listing of municipal solid waste landfills under CAA section 111. In the landfills New Source Performance Standard (NSPS) EPA did not consider health effects resulting from climate change much less draw any conclusions about health effects from climate change being health or welfare effects. If anything, the landfills NSPS is consistent with EPA's approach. In the proposed rule, EPA stated: ''The EPA has documented many cases of acute injury and death caused by explosions and fires related to municipal landfill gas emissions. In addition to these health effects, the associated property damage is a welfare effect'' (56 FR 24474). EPA considered injury and death from fires resulting from landfill gasses to be health effects. Yet the injury did not result from direct exposure to the pollutant (landfill gas). Instead, the injury resulted from the combustion of the pollutant—the injury is essentially an indirect effect of the pollutant. Yet, as with this action, EPA considered the injury as a human health effect.

Case law. Several commenters argue that EPA's proposed endangerment finding was inconsistent with *NRDC* v. *EPA*, 902 F.2d 962 (DC Cir 1990). Commenters argue that in rejecting the argument that EPA must consider the health effects of increased unemployment that could result from a more stringent primary NAAQS standard, the DC Circuit explained that, ''[i]t is only the health effects relating to pollutants in the air that EPA may consider.'' *Id.* at 973. Several commenters further argue that EPA later relied on that holding to defend its decision to set a primary NAAQS for ozone based solely on direct health effects of ozone. Citing, *EPA Pet'n for Rehearing, Am. Trucking Ass'n* v. *EPA*, No. 97–1440 (DC Cir. June 28, 1999) (''ATA I'') (arguing that the primary NAAQS should be set through consideration of only ''direct adverse effects on public health, and not indirect, allegedly beneficial effects.'')

The *NRDC* case is not contrary to EPA's endangerment finding. In *NRDC*, petitioner American Iron and Steel Institute argued that EPA had to consider the costs of health consequences that might arise from increased unemployment. The court ruled that, ''[c]onsideration of costs associated with alleged health risks from unemployment would be flatly inconsistent with the statute, legislative history and case law on this point.'' 902 F.2d at 973. The cases cited by the court in support of its decision all hold that EPA may not consider economic or technological feasibility in establishing a NAAQS. The *NRDC* decision does not establish a precedent that the CAA prohibits EPA from considering indirect health effects as a public health issue rather than a public welfare issue.

EPA also believes reliance on the Agency's petition for rehearing in noted above is misplaced. In that case, EPA did not argue that indirect beneficial health effects were not public health issues. Instead EPA argued that under the CAA, it did not have to consider such indirect beneficial health effects of an air pollutant when setting the health based primary NAAQS. EPA was interpreting the NAAQS standard setting provisions of CAA section 109, and argued that they were intended to address only certain public health impacts, those that were adverse, and were not intended to address indirect, beneficial public health impacts. The issue in the case was not whether indirect health effects are relevant for purposes of making an endangerment decision concerning public health, but rather whether EPA must consider such beneficial health effects in establishing a primary NAAQS under CAA section 109. EPA's interpretation of CAA section 109 was rejected in *ATA* v. *EPA*, 175 F.3d at 1027 (1999) *reh'g granted in part and denied in part*, 195 F.3d at 4 (DC Cir. 1999). The court made it clear that the potential indirect beneficial impact of ambient ozone on public health from screening UVB rays needed to be considered when setting the NAAQS to protect public health. As discussed above, EPA has done just that as noted above in the UV–B context. Moreover, as discussed in Section II of these Findings, EPA is doing that here as well (*e.g.*, considering any benefits from reduced cold weather related deaths).

ii. EPA's Treatment and Balancing of Heat- vs. Cold-Related Public Health Risks Was Reasonable

A number of public commenters maintain that the risk of heat waves in the future will be modulated by adaptive measures. The Administrator is aware of the potential benefits of adaptation in reducing heat-related morbidity and mortality and recognizes most heat-related deaths are preventable. Nonetheless, the Administrator notes the assessment literature [30] indicates heat is the leading weather-related killer in the United States even though countermeasures have been employed in many vulnerable areas. Given projections for heat waves of greater frequency, magnitude, and duration coupled with a growing population of older adults (among the most vulnerable groups to this hazard), the risk of adverse health outcomes from heat waves is expected to increase. Intervention and response measures could certainly reduce the risk, but as we have noted, the need to adapt supports an increase in risk or endangerment. For a general discussion about EPA's treatment of adaptation see Section III.C of these Findings.

Several commenters also suggest cold-related mortality will decrease more than heat-related mortality will increase, which indicates a net reduction in temperature-related mortality. Some commenters point to research suggesting migration to warmer climates has contributed to the increased longevity of some Americans, implying climate warming will have benefits for health. The Administrator is very clear that the exact balance of how heat- versus cold-related mortality will change in the future is uncertain; however, the assessment literature points to evidence suggesting that the increased risk from heat would exceed the decreased risk from cold in a warming climate. The Administrator does not dispute research indicating the benefits of migration to a warmer climate and nor that average climate warming may indeed provide health benefits in some areas. These points are reflected in the TSD's statement projecting less cold-related health effects. The Administrator considers these potential warming benefits independent of the potential negative effects of extreme heat events which are projected to increase under future climate change scenarios affecting vulnerable groups and communities.

[30] Karl *et al.* (2009).

iii. EPA Was Reasonable To Find That the Air Quality Impacts of Climate Change Contribute to the Endangerment of Public Health

Several commenters suggest that air quality effects of climate change will be addressed through the CAA's NAAQS process, as implemented by the State Implementation Plans (SIP) and national regulatory programs. According to these commenters, these programs will ensure no adverse impact on public health due to climate change. Though climate change may cause certain air pollutant ambient concentrations to increase, States will continue to be compelled to meet the standards. So, while additional measures may be necessary, and result in increased costs, these commenters assert that, ultimately, public health will be protected by the continued existence of the NAAQS and therefore no endangerment with respect to this particular climate change-related impact will occur. One commenter states that EPA inappropriately assigns air quality risk to climate change that will be addressed through other programs. The CAA provides a mechanism to meet the standards and additional control measures consistent with the CAA will be adopted in the future, keeping pollution below unhealthy levels. The commenters state that the fact that NAAQS are in place that require EPA to fulfill its legal obligation to prevent this particular form of endangerment to public health.

EPA does have in place NAAQS for ozone, which are premised on the harmfulness of ozone to public health and welfare. These standards and their accompanying regulatory regime have helped to reduce the dangers from ozone in the United States. However, substantial challenges remain with respect to achieving the air quality protection promised by the NAAQS for ozone. It is the Administrator's view that these challenges will be exacerbated by climate change.

In addition, the control measures to achieve attainment with a NAAQS are a mitigation measure aimed at reducing emissions of ozone precursors. As discussed in Section III.C of these Findings, EPA is not considering the impacts of mitigation with respect to future reductions in emissions of greenhouse gases. For the same reasons, EPA is reasonably not considering mitigation in the form of the control measures that will need to be adopted in the future to reduce emissions of ozone precursors and thereby address the increased ambient ozone levels that can occur because of climate change.

It is important to note that controls to meet the NAAQS are typically put in place only *after* air quality concentrations exceeding the standard are detected. Furthermore, implementation of controls to reduce ambient concentrations of pollutants occurs over an extended time period, ranging from three years to more than twenty years depending on the pollutant and the seriousness of the nonattainment problem. Thus, while the CAA provides mechanisms for addressing adverse health effects and the underlying air quality exacerbation over time, it will not prevent the adverse impacts in the interim. Given the serious nature of the health effects at issue—including respiratory and cardiovascular disease leading to hospital admissions, emergency department visits, and premature mortality—this increase in adverse impacts during the time before additional controls can be implemented is a serious public health concern. Historically, a large segment of the U.S. population has lived in areas exceeding the NAAQS, despite the CAA and its implementation efforts. Half of all Americans, 158 million people, live in counties where air pollution exceeds national health standards.[31] Where attainment of the NAAQS is especially difficult, leading to delays in meeting attainment deadlines, the health effects of increased ozone due to climate change may be substantial.

It is also important to note that it may not be possible for States and Tribes to plan accurately for the impacts of climate change in developing control strategies for nonattainment areas. As noted in the TSD and EPA's 2009 Interim Assessment report (IA), climate change is projected to lead to an increase in the variability of weather, and this may increase peak pollution events including increases in ozone exceedances. While the modeling studies in the IA all show significant future changes in meteorological quantities, there is also significant variability across the simulations in the spatial patterns of these future changes, making it difficult to select a set of future meteorological data for planning purposes. At this time, models used to develop plans to attain the NAAQS do not take potential changes in future meteorology into consideration. Inability to predict the frequency and magnitude of such events could lead to an underestimation of the controls needed to bring areas into attainment, and a prolonged period during which adverse health impacts continue to occur.

Even in areas that meet the NAAQS currently, air quality may deteriorate sufficiently to cause adverse health effects for some individuals. Some at-risk individuals, for example those with preexisting health conditions or other characteristics which increase their risk for adverse effects upon exposure to PM or ozone, may experience health effects at levels below the standard. Current evidence suggests that there is no threshold for PM or ozone concentrations below which no effects can be observed. Therefore, increases in ozone or PM in locations that currently meet the standards would likely result in additional adverse health effects for some individuals, even though the pollution increase might not be sufficient to cause the area to be designated nonattainment. While the NAAQS is set to protect public health with an adequate margin of safety, it is recognized that in attainment areas there may be individuals who remain at greater risk from an increase in ozone levels. The clear risk to the public from ozone increases in nonattainment areas, in combination with the risk to some individuals in attainment areas, supports the finding that overall the public health is endangered by increases in ozone resulting from climate change.

Finally, it is also important to note that not all air pollution events are subject to CAA controls under the NAAQS implementation provisions. ''Exceptional events'' are events for which the normal planning and regulatory process established by the CAA is not appropriate (72 FR 13561). Emissions from some events, including some wildfires, are not reasonably controllable or preventable. Such emissions, however, can adversely impact public health and welfare and are expected to increase due to climate change. As described in the TSD, PM emissions from wildfires can contribute to acute and chronic illnesses of the respiratory system, particularly in children, including pneumonia, upper respiratory diseases, asthma and chronic obstructive pulmonary disease. The IPCC (Field et al., 2007) reported with very high confidence that in North America, disturbances like wildfires are increasing and are likely to intensify in a warmer future with drier soils and longer growing seasons.

2. The Air Pollution Is Reasonably Anticipated to Endanger Public Welfare

The Administrator also finds that the well-mixed greenhouse gas air pollution may reasonably be anticipated to

[31] U.S. EPA (2008) National Air Quality: Status and Trends Through 2007. EPA–454/R–08–006, November 2008.

endanger public welfare, both for current and future generations.

As with public health, the Administrator considered the multiple pathways in which the greenhouse gas air pollution and resultant climate change affect climate-sensitive sectors, and the impact this may have on public welfare. These sectors include food production and agriculture; forestry; water resources; sea level rise and coastal areas; energy, infrastructure, and settlements; and ecosystems and wildlife. The Administrator also considered impacts on the U.S. population from climate change effects occurring outside of the United States, such as national security concerns for the United States that may arise as a result of climate change impacts in other regions of the world. The Administrator examined each climate-sensitive sector individually, informed by the summary of the scientific assessments contained in the TSD, and the full record before EPA, and weighed the extent to which the risks and impacts within each sector support or do not support a positive endangerment finding in her judgment. The Administer then viewed the full weight of evidence looking across all sectors to reach her decision regarding endangerment to public welfare.

a. Food Production and Agriculture

Food production and agriculture within the United States is a sector that will be affected by the combined effects of elevated carbon dioxide concentrations and associated climate change. The Administrator considered how these effects, both adverse and beneficial, are affecting the agricultural sector now and in the future, and over different regions of the United States, taking into account that different regions of the country specialize in different agricultural products with varying degrees of sensitivity and vulnerability to elevated carbon dioxide levels and associated climate change.

Elevated carbon dioxide concentrations can have a stimulatory effect on grain and oilseed crop yield, as may modest temperature increases and a longer growing season that results. A report under the USGCRP concluded that, with increased carbon dioxide and temperature, the life cycle of grain and oilseed crops will likely progress more rapidly. However, such beneficial influences need to be considered in light of various other effects. For example, the literature indicates that elevated carbon dioxide concentrations may also enhance pest and weed growth. Pests and weeds can reduce crop yields, cause economic losses to farmers, and require management control options. How climate change (elevated carbon dioxide, increased temperatures, altered precipitation patterns, and changes in the frequency and intensity of extreme events) may affect the prevalence of pests and weeds is an issue of concern for food production and the agricultural sector. Research on the combined effects of elevated carbon dioxide and climate change on pests, weeds, and disease is still limited. In addition, higher temperature increases, changing precipitation patterns and variability, and any increases in ground-level ozone induced by higher temperatures, can work to counteract any direct stimulatory carbon dioxide effect, as well as lead to their own adverse impacts. There may be large regional variability in the response of food production and agriculture to climate change.

For grain and oilseed crop yields, there is support for the view that in the near term climate change may have a beneficial effect, largely through increased temperature and increased carbon dioxide levels. However there are also factors noted above, some of which are less well studied and understood, which would tend to offset any near term benefit, leaving significant uncertainty about the actual magnitude of any overall benefit. The USGCRP report also concluded that as temperature rises, these crops will increasingly begin to experience failure, especially if climate variability increases and precipitation lessens or becomes more variable.

A key uncertainty is how human-induced climate change may affect the intensity and frequency of extreme weather events such as droughts and heavy storms. These events have the potential to have serious negative impact on U.S. food production and agriculture, but are not always taken into account in studies that examine how average conditions may change as a result of carbon dioxide and temperature increases. Changing precipitation patterns, in addition to increasing temperatures and longer growing seasons, can change the demand for irrigation requirements, potentially increasing irrigation demand.

Another key uncertainty concerns the many horticultural crops (*e.g.,* tomatoes, onions, fruits), which make up roughly 40 percent of total crop value in the United States. There is relatively little information on their response to carbon dioxide, and few crop simulation models, but according to the literature, they are very likely to be more sensitive to the various effects of climate change than grain and oilseed crops.

With respect to livestock, higher temperatures will very likely reduce livestock production during the summer season in some areas, but these losses will very likely be partially offset by warmer temperatures during the winter season. The impact on livestock productivity due to increased variability in weather patterns will likely be far greater than effects associated with the average change in climatic conditions. Cold-water fisheries will likely be negatively affected; warm-water fisheries will generally benefit; and the results for cool-water fisheries will be mixed, with gains in the northern and losses in the southern portions of ranges.

Finally, with respect to irrigation requirements, the adverse impacts of climate change on irrigation water requirements may be significant.

There is support for the view that there may be a benefit in the near term in the crop yield for certain crops. This potential benefit is subject to significant uncertainty, however, given the offsetting impact on the yield of these crops from a variety of other climate change impacts that are less well understood and more variable. Any potential net benefit is expected to change to a disbenefit in the longer term. In addition, there is clear risk that the sensitivity of a major segment of the total crop market, the horticultural sector, may lead to adverse affects from climate change. With respect to livestock production and irrigation requirements, climate change is likely to have adverse effects in both the near and long terms. The impact on fisheries varies, and would appear to be best viewed as neutral overall.

There is a potential for a net benefit in the near term for certain crops, but there is significant uncertainty about whether this benefit will be achieved given the various potential adverse impacts of climate change on crop yield, such as the increasing risk of extreme weather events. Other aspects of this sector are expected to be adversely affected by climate change, including livestock management and irrigation requirements, and there is a risk of adverse effect on a large segment of the total crop market. For the near term, the concern over the potential for adverse effects in certain parts of the agriculture sector appears generally comparable to the potential for benefits for certain crops.

However, considering the trend over near- and long-term future conditions, the Administrator finds that the body of evidence points towards increasing risk of net adverse impacts on U.S. food production and agriculture, with the potential for significant disruptions and crop failure in the future.

b. Forestry

The factors that the Administrator considered for the U.S. forest sector are similar to those for food production and agriculture. There is the potential for beneficial effects due to elevated concentrations of carbon dioxide and increased temperature, as well as the potential for adverse effects from increasing temperatures, changing precipitation patterns, increased insects and disease, and the potential for more frequent and severe extreme weather events. The potential beneficial effects are better understood and studied, and are limited to certain areas of the country and types of forests. The adverse effects are less certain, more variable, and also include some of the most serious adverse effects such as increased wildfire, drought, and major losses from insects and disease. As with food production and agriculture, the judgment to be made is largely a qualitative one, balancing impacts that vary in certainty and magnitude, with the end result being a judgment as to the overall direction and general level of concern.

According to the underlying science assessment reports, climate change has very likely increased the size and number of wildfires, insect outbreaks, and tree mortality in the Interior West, the Southwest, and Alaska, and will continue to do so. Rising atmospheric carbon dioxide levels will very likely increase photosynthesis for forests, but the increased photosynthesis will likely only increase wood production in young forests on fertile soils. Nitrogen deposition and warmer temperatures have very likely increased forest growth where water is not limiting and will continue to do so in the near future.

An increased frequency of disturbance (such as drought, storms, insect-outbreaks, and wildfire) is at least as important to forest ecosystem function as incremental changes in temperature, precipitation, atmospheric carbon dioxide, nitrogen deposition, and ozone pollution. Disturbances partially or completely change forest ecosystem structure and species composition, cause short-term productivity and carbon storage loss, allow better opportunities for invasive alien species to become established, and command more public and management attention and resources. The combined effects of expected increased temperature, carbon dioxide, nitrogen deposition, ozone, and forest disturbance on soil processes and soil carbon storage remain unclear.

Precipitation and weather extremes are key to many forestry impacts, accounting for part of the regional variability in forest response. If existing trends in precipitation continue, it is expected that forest productivity will likely decrease in the Interior West, the Southwest, eastern portions of the Southeast, and Alaska, and that forest productivity will likely increase in the northeastern United States, the Lake States, and in western portions of the Southeast. An increase in drought events will very likely reduce forest productivity wherever such events occur.

Changes in disturbance patterns are expected to have a substantial impact on overall gains or losses. More prevalent wildfire disturbances have recently been observed in the United States. Wildfires and droughts, among other extreme events (*e.g.,* hurricanes) that can cause forest damage, pose the largest threats over time to forest ecosystems.

For the near term, the Administrator believes the beneficial impact on forest growth and productivity in certain parts of the country from climate change to be more than offset by the clear risk from the more significant and serious adverse effects from the observed increases in wildfires, combined with the adverse impacts on growth and productivity in other areas of the country and the serious risks from the spread of destructive pests and disease. Increased wildfires can also increase particulate matter and thus create public health concerns as well. For the longer term, the Administrator views the risk from adverse effects to increase over time, such that overall climate change presents serious adverse risks for forest productivity. The Administrator therefore finds there is compelling reason to find that the greenhouse gas air pollution endangers U.S. forestry in both the near and long term, with the support for a positive endangerment finding only increasing as one considers expected future conditions in which temperatures continue to rise.

c. Water Resources

The sensitivity of water resources to climate change is very important given the increasing demand for adequate water supplies and services for agricultural, municipal, and energy and industrial uses, and the current strains on this resource in many parts of the country.

According to the assessment literature, climate change has already altered, and will likely continue to alter, the water cycle, affecting where, when, and how much water is available for all uses. With higher temperatures, the water-holding capacity of the atmosphere and evaporation into the atmosphere increase, and this favors increased climate variability, with more intense precipitation and more droughts.

Climate change is causing and will increasingly cause shrinking snowpack induced by increasing temperature. In the western United States, there is already well-documented evidence of shrinking snowpack due to warming. Earlier meltings, with increased runoff in the winter and early spring, increase flood concerns and also result in substantially decreased summer flows. This pattern of reduced snowpack and changes to the flow regime pose very serious risks to major population regions, such as California, that rely on snowmelt-dominated watersheds for their water supply. While increased precipitation is expected to increase water flow levels in some eastern areas, this may be tempered by increased variability in the precipitation and the accompanying increased risk of floods and other concerns such as water pollution.

Warmer temperatures and decreasing precipitation in other parts of the country, such as the Southwest, can sustain and amplify drought impacts. Although drought has been more frequent and intense in the western part of the United States, the East is also vulnerable to droughts and attendant reductions in water supply, changes in water quality and ecosystem function, and challenges in allocation. The stress on water supplies on islands is expected to increase.

The impact of climate change on groundwater as a water supply is regionally variable; efforts to offset declining surface water availability due to increasing precipitation variability may be hampered by the fact that groundwater recharge will decrease considerably in some already water-stressed regions. In coastal areas, the increased salinization from intrusion of salt water is projected to have negative effects on the supply of fresh water.

Climate change is expected to have adverse effects on water quality. The IPCC concluded with high confidence that higher water temperatures, increased precipitation intensity, and longer periods of low flows exacerbate many forms of water pollution and can impact ecosystems, human health, and water system reliability and operating costs. These changes will also exacerbate many forms of water pollution, potentially making attainment of water quality goals more difficult. Water pollutants of concern that are particularly relevant to climate change effects include sediment, nutrients, organic matter, pathogens, pesticides, salt, and thermal pollution. As waters become warmer, the aquatic life they now support will be replaced by other species better adapted to warmer water. In the long term, warmer water, changing flows, and decreased water quality may result in deterioration of aquatic ecosystems.

Climate change will likely further constrain already over-allocated water resources in some regions of the United States, increasing competition among agricultural, municipal, industrial, and ecological uses. Although water management practices in the United States are generally advanced, particularly in the West, the reliance on past conditions as the basis for current and future planning may no longer be appropriate, as climate change increasingly creates conditions well outside of historical observations. Increased incidence of extreme weather and floods may also overwhelm or damage water treatment and management systems, resulting in water quality impairments. In the Great Lakes and major river systems, lower water levels are likely to exacerbate challenges relating to water quality, navigation, recreation, hydropower generation, water transfers, and bi-national relationships.

The Administrator finds that the total scientific literature provides compelling support for finding that greenhouse gas air pollution endangers the water resources important for public welfare in the United States, both for current and future generations. The adequacy of water supplies across large areas of the country is at serious risk from climate change. Even areas of the country where an increase in water flow is projected could face water resource problems from the variability of the supply and water quality problems associated with precipitation variability, and could face the serious adverse effects from risks from floods and drought. Climate change is expected to adversely affect water quality. There is an increased risk of serious adverse effects from extreme events of flooding and drought. The severity of risks and impacts may only increase over time with accumulating greenhouse gas concentrations and associated temperature increases and precipitation changes.

d. Sea Level Rise and Coastal Areas

A large percentage of the U.S. population lives in coastal areas, which are particularly vulnerable to the risks posed by climate change. The most vulnerable areas are the Atlantic and Gulf Coasts, the Pacific Islands, and parts of Alaska.

According to the assessment literature, sea level is rising along much of the U.S. coast, and the rate of change will very likely increase in the future, exacerbating the impacts of progressive inundation, storm-surge flooding, and shoreline erosion. Cities such as New Orleans, Miami, and New York are particularly at risk, and could have difficulty coping with the sea level rise projected by the end of the century under a higher emissions scenario. Population growth and the rising value of infrastructure increases the vulnerability to climate variability and future climate change in coastal areas. Adverse impacts on islands present concerns for Hawaii and the U.S. territories. Reductions in Arctic sea ice increases extreme coastal erosion in Alaska, due to the increased exposure of the coastline to strong wave action. In the Great Lakes, where sea level rise is not a concern, both extremely high and low water levels resulting from changes to the hydrological cycle have been damaging and disruptive to shoreline communities.

Coastal wetland loss is being observed in the United States where these ecosystems are squeezed between natural and artificial landward boundaries and rising sea levels. Up to 21 percent of the remaining coastal wetlands in the U.S. mid-Atlantic region are potentially at risk of inundation between 2000 and 2100. Coastal habitats will likely be increasingly stressed by climate change impacts interacting with development and pollution.

Although increases in mean sea level over the 21st century and beyond will inundate unprotected, low-lying areas, the most devastating impacts are likely to be associated with storm surge. Superimposed on expected rates of sea level rise, projected storm intensity, wave height, and storm surge suggest more severe coastal flooding and erosion hazards. Higher sea level provides an elevated base for storm surges to build upon and diminishes the rate at which low-lying areas drain, thereby increasing the risk of flooding from rainstorms. In New York City and Long Island, flooding from a combination of sea level rise and storm surge could be several meters deep. Projections suggest that the return period of a 100-year flood event in this area might be reduced to 19–68 years, on average, by the 2050s, and to 4–60 years by the 2080s. Additionally, some major urban centers in the United States, such as areas of New Orleans are situated in low-lying flood plains, presenting increased risk from storm surges.

The Administrator finds that the most serious risk of adverse effects is presented by the increased risk of storm surge and flooding in coastal areas from sea level rise. Current observations of sea level rise are now contributing to increased risk of storm surge and flooding in coastal areas, and there is reason to find that these areas are now endangered by human-induced climate change. The conclusion in the assessment literature that there is the potential for hurricanes to become more intense with increasing temperatures (and even some evidence that Atlantic hurricanes have already become more intense) reinforces the judgment that coastal communities are now endangered by human-induced climate change, and may face substantially greater risk in the future. The Administrator has concluded that even if there is a low probability of raising the destructive power of hurricanes, this threat is enough to support a finding that coastal communities are endangered by greenhouse gas air pollution.

In addition, coastal areas face other adverse impacts from sea level rise such as shoreline retreat, erosion, wetland loss and other effects. The increased risk associated with these adverse impacts also endangers the welfare of current and future generations, with an increasing risk of greater adverse impacts in the future.

Overall, the evidence on risk of adverse impacts for coastal areas from sea level rise provides clear support for finding that greenhouse gas air pollution endangers the welfare of current and future generations.

e. Energy, Infrastructure and Settlements

The Administrator also considered the impacts of climate change on energy consumption and production, and on key climate-sensitive aspects of the nation's infrastructure and settlements.

For the energy sector, the Administrator finds clear evidence that temperature increases will change heating and cooling demand, and to varying degrees across the country; however, under current conditions it is unclear whether or not net demand will increase or decrease. While the impacts on net energy demand may be viewed as generally neutral for purposes of making an endangerment determination, climate change is expected to call for an increase in electricity production, especially supply for peak demand. The U.S. energy sector, which relies heavily on water for cooling capacity and hydropower, may be adversely impacted by changes to water supply in reservoirs and other water bodies.

With respect to infrastructure, climate change vulnerabilities of industry, settlement and society are mainly related to extreme weather events rather than to gradual climate change. The significance of gradual climate change, *e.g.*, increases in the mean temperature, lies mainly in changes in the intensity and frequency of extreme events. Extreme weather events could threaten U.S. energy infrastructure (transmission and distribution), transportation infrastructure (roads, bridges, airports and seaports), water infrastructure, and other built aspects of human settlements. Moreover, soil subsidence caused by the melting of permafrost in the Arctic region is a risk to gas and oil pipelines, electrical transmission towers, roads, and water systems. Vulnerabilities for industry, infrastructures, settlements, and society to climate change are generally greater in certain high-risk locations, particularly coastal and riverine areas, and areas whose economies are closely linked with climate-sensitive resources. Additionally, infrastructures are often connected, meaning that an impact on one can also affect others.

A significant fraction of U.S. infrastructure is located in coastal areas. In these locations, rising sea levels are likely to lead to direct losses (*e.g.,* equipment damage from flooding) as well as indirect effects such as the costs associated with raising vulnerable assets to higher levels. Water infrastructure, including drinking water and wastewater treatment plants, and sewer and storm water management systems, may be at greater risk of flooding, sea level rise and storm surge, low flows, saltwater intrusion, and other factors that could impair performance and damage costly investments.

Within settlements experiencing climate change stressors, certain parts of the population may be especially vulnerable based on their circumstances. These include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. In Alaska, indigenous communities are likely to experience disruptive impacts, including shifts in the range or abundance of wild species crucial to their livelihoods and well-being.

Overall, the evidence strongly supports the view that climate change presents risks of serious adverse impacts on public welfare from the risk to energy production and distribution as well as risks to infrastructure and settlements.

f. Ecosystems and Wildlife

The Administrator considered the impacts of climate change on ecosystems and wildlife and the services they provide. The Administrator finds clear evidence that climate change is exerting major influences on natural environments and biodiversity, and these influences are generally expected to grow with increased warming. Observed changes in the life cycles of plants and animals include shifts in habitat ranges, timing of migration patterns, and changes in reproductive timing and behavior.

The underlying assessment literature finds with high confidence that substantial changes in the structure and functioning of terrestrial ecosystems are very likely to occur with a global warming greater than 2 to 3 °C above pre-industrial levels, with predominantly negative consequences for biodiversity and the provisioning of ecosystem goods and services. With global average temperature changes above 2 °C, many terrestrial, freshwater, and marine species (particularly endemic species) are at a far greater risk of extinction than in the geological past. Climate change and ocean acidification will likely impair a wide range of planktonic and other marine calcifiers such as corals. Even without ocean acidification effects, increases in sea surface temperature of about 1–3 °C are projected to result in more frequent coral bleaching events and widespread mortality. In the Arctic, wildlife faces great challenges from the effects of climatic warming, as projected reductions in sea ice will drastically shrink marine habitat for polar bears, ice-inhabiting seals, and other animals.

Some common forest types are projected to expand, such as oak-hickory, while others are projected to contract, such as maple-beech-birch. Still others, such as spruce-fir, are likely to disappear from the contiguous United States. Changes in plant species composition in response to climate change can increase ecosystem vulnerability to other disturbances, including wildfires and biological invasion. Disturbances such as wildfires and insect outbreaks are increasing in the United States and are likely to intensify in a warmer future with warmer winters, drier soils and longer growing seasons. The areal extent of drought-limited ecosystems is projected to increase 11 percent per °C warming in the United States. In California, temperature increases greater than 2 °C may lead to conversion of shrubland into desert and grassland ecosystems and evergreen conifer forests into mixed deciduous forests. Greater intensity of extreme events may alter disturbance regimes in coastal ecosystems leading to changes in diversity and ecosystem functioning. Species inhabiting salt marshes, mangroves, and coral reefs are likely to be particularly vulnerable to these effects.

The Administrator finds that the total scientific record provides compelling support for finding that the greenhouse gas air pollution leads to predominantly negative consequences for biodiversity and the provisioning of ecosystem goods and services for ecosystems and wildlife important for public welfare in the U.S., both for current and future generations. The severity of risks and impacts may only increase over time with accumulating greenhouse gas concentrations and associated temperature increases and precipitation changes.

g. Summary of the Administrator's Finding of Endangerment to Public Welfare

The Administrator has considered how elevated concentrations of the well-mixed greenhouse gases and associated climate change affect public welfare by evaluating numerous and far-ranging risks to food production and agriculture, forestry, water resources, sea level rise and coastal areas, energy, infrastructure, and settlements, and ecosystems and wildlife. For each of these sectors, the evidence provides support for a finding of endangerment to public welfare. The evidence concerning adverse impacts in the areas of water resources and sea level rise and coastal areas provide the clearest and strongest support for an endangerment finding, both for current and future generations. Strong support is also found in the evidence concerning infrastructure and settlements, as well ecosystems and wildlife. Across the sectors, the potential serious adverse impacts of extreme events, such as wildfires, flooding, drought, and extreme weather conditions provide strong support for such a finding.

Water resources across large areas of the country are at serious risk from climate change, with effects on water supplies, water quality, and adverse effects from extreme events such as floods and droughts. Even areas of the country where an increase in water flow is projected could face water resource problems from the supply and water quality problems associated with temperature increases and precipitation variability, and could face the increased risk of serious adverse effects from extreme events, such as floods and drought. The severity of risks and impacts is likely to increase over time with accumulating greenhouse gas concentrations and associated temperature increases and precipitation changes.

Overall, the evidence on risk of adverse impacts for coastal areas provides clear support for a finding that greenhouse gas air pollution endangers the welfare of current and future generations. The most serious potential adverse effects are the increased risk of storm surge and flooding in coastal areas from sea level rise and more intense storms. Observed sea level rise is already increasing the risk of storm surge and flooding in some coastal areas. The conclusion in the assessment literature that there is the potential for hurricanes to become more intense (and even some evidence that Atlantic hurricanes have already become more intense) reinforces the judgment that coastal communities are now endangered by human-induced climate change, and may face substantially greater risk in the future. Even if there is a low probability of increasing the destructive power of hurricanes, this threat is enough to support a finding that coastal communities are endangered by greenhouse gas air pollution. In addition, coastal areas face other adverse impacts from sea level rise such as land loss due to inundation, erosion, wetland submergence, and habitat loss. The increased risk associated with these adverse impacts also endangers public welfare, with an increasing risk of greater adverse impacts in the future.

Strong support for an endangerment finding is also found in the evidence concerning energy, infrastructure, and settlements, as well ecosystems and wildlife. While the impacts on net energy demand may be viewed as generally neutral for purposes of making an endangerment determination, climate change is expected to result in an increase in electricity production, especially to meet peak demand. This increase may be exacerbated by the potential for adverse impacts from climate change on hydropower resources as well as the potential risk of serious adverse effects on energy infrastructure from extreme events. Changes in extreme weather events threaten energy, transportation, and water resource infrastructure. Vulnerabilities of industry, infrastructure, and settlements to climate change are generally greater in high-risk locations, particularly coastal and riverine areas, and areas whose economies are closely linked with climate-sensitive resources. Climate change will likely interact with and possibly exacerbate ongoing environmental change and environmental pressures in settlements, particularly in Alaska where indigenous communities are facing major environmental and cultural impacts on their historic lifestyles. Over the 21st century, changes in climate will cause some species to shift north and to higher elevations and fundamentally rearrange U.S. ecosystems. Differential capacities for range shifts and constraints from development, habitat fragmentation, invasive species, and broken ecological connections will likely alter ecosystem structure, function, and services, leading to predominantly negative consequences for biodiversity and the provision of ecosystem goods and services.

With respect to food production and agriculture, there is a potential for a net benefit in the near term for certain crops, but there is significant uncertainty about whether this benefit will be achieved given the various potential adverse impacts of climate change on crop yield, such as the increasing risk of extreme weather events. Other aspects of this sector may be adversely affected by climate change, including livestock management and irrigation requirements, and there is a risk of adverse effect on a large segment of the total crop market. For the near term, the concern over the potential for adverse effects in certain parts of the agriculture sector appears generally comparable to the potential for benefits for certain crops. However, the body of evidence points towards increasing risk of net adverse impacts on U.S. food production and agriculture over time, with the potential for significant disruptions and crop failure in the future.

For the near term, the Administrator finds the beneficial impact on forest growth and productivity in certain parts of the country from elevated carbon dioxide concentrations and temperature increases to date is offset by the clear risk from the observed increases in wildfires, combined with risks from the spread of destructive pests and disease. For the longer term, the risk from adverse effects increases over time, such that overall climate change presents serious adverse risks for forest productivity. There is compelling reason to find that the support for a positive endangerment finding increases as one considers expected future conditions where temperatures continue to rise.

Looking across all of the sectors discussed above, the evidence provides compelling support for finding that greenhouse gas air pollution endangers the public welfare of both current and future generations. The risk and the severity of adverse impacts on public welfare are expected to increase over time.

h. Impacts in Other World Regions That Can Affect the U.S Population

While the finding of endangerment to public health and welfare discussed above is based on impacts in the United States, the Administrator also considered how human-induced climate change in other regions of the world may in turn affect public welfare in the United States. According to the USGCRP report of June 2009 and other sources, climate change impacts in certain regions of the world may exacerbate problems that raise humanitarian, trade, and national security issues for the United States.[32] The IPCC identifies the most vulnerable world regions as the Arctic, because of the effects of high rates of projected warming on natural systems; Africa, especially the sub-Saharan region, because of current low adaptive capacity as well as climate change; small islands, due to high exposure of population and infrastructure to risk of sea-level rise and increased storm surge; and Asian mega-deltas, such as the Ganges-Brahmaputra and the Zhujiang, due to large populations and high exposure to sea level rise, storm surge, and river flooding. Climate change has been described as a potential threat multiplier with regard to national security issues.

The Administrator acknowledges these kinds of risks do not readily lend themselves to precise analyses or future projections. However, given the unavoidable global nature of the climate change problem, it is appropriate and prudent to consider how impacts in other world regions may present risks to the U.S. population. Because human-induced climate change has the potential to aggravate natural resource, trade, and humanitarian issues in other world regions, which in turn may contribute to the endangerment of public welfare in the United States, this provides additional support for the Administrator's finding that the greenhouse gas air pollution is reasonably anticipated to endanger the public welfare of current and future

[32] "In an increasingly interdependent world, U.S. vulnerability to climate change is linked to the fates of other nations. For example, conflicts or mass migrations of people resulting from food scarcity and other resource limits, health impacts or environmental stresses in other parts of the world could threaten U.S. national security." (Karl *et al.*, 2009).

generations of the United States population.

i. Summary of Key Public Comments on Endangerment to Public Welfare

Several public commenters point out the anticipated benefits that increasing carbon dioxide levels and temperatures will have on agricultural crops. In addition, commenters note how U.S. agricultural productivity, in particular, has been steadily rising over the last 100 years. Responses to major comments are found here and more detailed responses are found in the Response to Comments document.

The Administrator acknowledges that plants including agricultural crops respond to carbon dioxide positively based on numerous well-documented studies. However, previous assessments of food production and agriculture have been modified to highlight increasing vulnerability, stress, and adverse impacts from climate change over time, based on improvements in the understanding of plant physiology, concern over impacts on plant pests and pathogens, and the implications of changes in average temperatures for temperature extremes and for changes in the patterns of precipitation and evaporation. While it is still the case today and for the next few years that climate change benefits agriculture in some places and harms them in others, the Administrator considers that the far larger temperature increases expected over coming decades and beyond on the ''business as usual'' trajectory will put significant stresses on agriculture and land resources in all regions of the United States. The Administrator prudently considers increased climate variability associated with a warming climate, which may overwhelm the positive plant responses from elevated carbon dioxide over time. Further, the effects of climate change on weeds, insect pests, and pathogens are recognized as key factors in determining plant damage in future decades. The Administrator also notes that scientific literature clearly supports the finding that drought frequency and severity are projected to increase in the future over much of the United States, which will likely reduce crop yields because of excesses or deficits of water. Vulnerability to extended drought, according to IPCC, has been documented as already increasing across North America. Further, based on review of the assessment literature, the Administrator considers multiple stresses, such as limited availability of water resources, loss of biodiversity, and air pollution, which are likely to increase sensitivity and reduce resilience in the agricultural sector to climate change over time.

Similar to food production and agriculture, public commenters often noted that forest productivity is projected to increase in the coming years due to the direct stimulatory effect of carbon dioxide on plant growth combined with warmer temperatures and thus extended growing seasons. The Administrator notes this phenomenon has been well documented by numerous studies but recognizes that increased productivity will be associated with significant variation at local and regional scales. The Administrator considers that climate strongly influences forest productivity and composition, and the frequency and magnitude of disturbances that impact forests. Based on the most recent IPCC assessment of the scientific literature, several recent studies confirm previous findings that temperature and precipitation changes in future decades will modify, and often limit, direct carbon dioxide effects on plants. For example, increased temperatures may reduce carbon dioxide effects indirectly, by increasing water demand. The Administrator also considers that new research more firmly establishes the negative impacts of increased climate variability. Projected changes in the frequency and severity of extreme climate events have significant consequences for forestry production and amplify existing stresses to land resources in the future.

Several public commenters maintain that wildfires are primarily the result of natural climatic factors and not climate change and dispute that they are or will increase in the future. The Administrator notes the scientific literature and assessment reports provide several lines of evidence that suggest wildfires will likely increase in frequency over the next several decades because of climate warming. Wildfires and droughts, among other extreme events (*e.g.,* hurricanes) that cause forest damage, pose the largest threats over time to forest ecosystems. The assessment literature suggests that large, stand-replacing wildfires will likely increase in frequency over the next several decades because of climate warming and general climate warming encourages wildfires by extending the summer period that dries fuels, promoting easier ignition and faster spread. Furthermore, current climate modeling studies suggest that increased temperatures and longer growing seasons will elevate wildfire risk in connection with increased aridity.

V. The Administrator's Finding That Emissions of Greenhouse Gases From CAA Section 202(a) Sources Cause or Contribute to the Endangerment of Public Health and Welfare

As discussed in Section IV.A of these Findings, the Administrator is defining the air pollution for purposes of the endangerment finding to be the elevated concentration of well-mixed greenhouse gases in the atmosphere. The second step of the two-part endangerment test is for the Administrator to determine whether the emission of any air pollutant emitted from new motor vehicles cause or contribute to this air pollution. This is referred to as the cause or contribute finding, and is the second finding by the Administrator in this action.

Section V.A of these Findings describes the Administrator's definition and scope of the air pollutant ''well-mixed greenhouse gases.'' Section V.B of these Findings puts forth the Administrator's finding that emissions of well-mixed greenhouse gases from new motor vehicles contribute to the air pollution which is reasonably anticipated to endanger public health and welfare. Section V.C of these Findings provides responses to some of the key comments on these issues. See Response to Comments document Volume 10 for responses to other significant comments on the cause or contribute finding. More detailed emissions data summarized in the discussion below can be found in Appendix B of the TSD.

A. The Administrator's Definition of the ''Air Pollutant''

As discussed in the Proposed Findings, to help appreciate the distinction between air pollution and air pollutant, the *air pollution* can be thought of as the total, cumulative stock in the atmosphere, while the *air pollutant,* can be thought of as the flow that changes the size of the total stock. Given this relationship, it is not surprising that the Administrator is defining the air pollutant similar to the air pollution; while the air pollution is the concentration (*e.g.,* stock) of the well-mixed greenhouse gases in the atmosphere, the air pollutant is the same combined grouping of the well-mixed greenhouse gases, the emissions of which are analyzed for contribution (*e.g.,* the flow into the stock).

Thus, the Administrator is defining the air pollutant as the aggregate group of the same six long-lived and directly-emitted greenhouse gases: Carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. As noted above, this definition of a single air pollutant made up of these well-mixed greenhouse gases is similar to definitions of other air pollutants that are comprised of substances that share common attributes with similar effects on public health or welfare (*e.g.,* particulate matter and volatile organic compounds).

The common attributes shared by these six greenhouse gases are discussed in detail in Section IV.A of these Findings, where the Administrator defined the ''air pollution'' for purposes of the endangerment finding. These same common attributes support the Administrator grouping these six greenhouse gases for purposes of defining a single air pollutant as well. These attributes include the fact that they are all greenhouse gases that are directly emitted (*i.e.,* they are not formed through secondary processes in the atmosphere from precursor emissions); they are sufficiently long-lived in the atmosphere such that, once emitted, concentrations of each gas become well mixed throughout the entire global atmosphere; and they exert a climate warming effect by trapping outgoing, infrared heat that would otherwise escape to space. Moreover, the radiative forcing effect of these six greenhouse gases is well understood.

Furthermore, these six greenhouse gases are currently the common focus of climate science and policy. For example, the UNFCCC, signed and ratified by the U.S. in 1992, requires its signatories to ''develop, periodically update, publish and make available * * * national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol [33], using comparable methodologies * * * '' [34] To date, the focus of UNFCCC actions and discussions has been on the six greenhouse gases that are the same focus of these findings. As a Party to the UNFCCC, EPA annually submits the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* to the Convention, which reports on national emissions of anthropogenic emissions of the well-mixed greenhouse gases. International discussions about a post-Kyoto agreement also focus on the well-mixed greenhouse gases.

As noted above, grouping of many substances with common attributes as a single pollutant is common practice under the CAA. Thus, doing so here is not novel. Indeed CAA section 302(g) defines air pollutant as ''any air pollutant agent or *combination of such agents,* * * * '' CAA § 302(g) (emphasis added). Thus, it is clear that the term ''air pollutant'' is not limited to individual chemical compounds. In determining that greenhouse gases are within the scope of this definition, the Supreme Court described section 302(g) as a ''sweeping'' and ''capacious'' definition that unambiguously included greenhouse gases, that are ''unquestionably 'agents' of air pollution.'' *Massachusetts* v. *EPA,* 549 U.S. at 528, 532, 529 n.26. Although the Court did not interpret the term ''combination of'' air pollution agents, there is no reason this phrase would be interpreted any less broadly. Congress used the term ''any'', and did not qualify the kind of combinations that the agency could define as a single air pollutant. Congress provided EPA broad discretion to determine appropriate combinations of compounds that should be treated as a singe air pollutant.[35]

For the same reasons discussed in Section IV.A above, at this time, only carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride share all of these common attributes and thus they are the only substances that the Administrator finds to meet the definition of ''well-mixed greenhouse gas'' at this time.[36] Also as noted above, if in the future other substances are shown to meet the same criteria they may be added to the definition of this single air pollutant.

The Administrator is aware that CAA section 202(a) source categories do not emit all of the substances meeting the definition of well-mixed greenhouse gases. But that does not change the fact that all of these greenhouse gases share the attributes that make grouping them as a single air pollutant reasonable. As discussed further below, the reasonableness of this grouping does not turn on the particular source category being evaluated in a contribution finding.

B. The Administrator's Finding Regarding Whether Emissions of the Air Pollutant From Section 202(a) Source Categories Cause or Contribute to the Air Pollution That May Be Reasonably Anticipated To Endanger Public Health and Welfare

The Administrator finds that emissions of the well-mixed greenhouse gases from new motor vehicles contribute to the air pollution that may reasonably be anticipated to endanger public health and welfare. This contribution finding is for all of the CAA section 202(a) source categories and the Administrator considered emissions from all of these source categories. The relevant mobile sources under CAA section 202 (a)(1) are ''any class or classes of new motor vehicles or new motor vehicle engines, * * *.'' CAA section 202(a)(1) (emphasis added). The new motor vehicles and new motor vehicle engines (hereinafter ''CAA section 202(a) source categories'') addressed are: Passenger cars, light-duty trucks, motorcycles, buses, and medium and heavy-duty trucks. Detailed combined greenhouse gas emissions data for CAA section 202(a) source categories are presented in Appendix B of the TSD.[37]

The Administrator reached her decision after reviewing emissions data on the contribution of CAA section 202(a) source categories relative to both global greenhouse gas emissions and U.S. greenhouse gas emissions. Given that CAA section 202(a) source categories are responsible for about 4 percent of total global greenhouse gas emissions, and for just over 23 percent of total U.S. greenhouse gas emissions, the Administrator finds that both of these comparisons, independently and together, support a finding that CAA section 202(a) source categories contribute to the air pollution that may be reasonably anticipated to endanger public health and welfare. The Administrator is not placing primary weight on either approach; rather she finds that both approaches clearly establish that emissions of the well-mixed greenhouse gases from section 202(a) source categories contribute to air pollution with may reasonably be anticipated to endanger public health and welfare. As the Supreme Court noted, ''[j]udged by any standard, U.S.

[33] The Montreal Protocol covers ozone-depleting substances which may also share physical attributes of the six key greenhouse gases in this action, but they do not share other attributes such as being the focus of climate science and policy. See section * * *.

[34] UNFCCC Art. 4.1(b).

[35] Indeed, the greenhouse gases hydrofluorocarbons and perfluorocarbons each are already a combination of multiple compounds.

[36] The term ''well-mixed greenhouse gases'' is based on one of the shared attributes discussed above—these greenhouse gases are sufficiently long-lived in the atmosphere such that, once emitted, concentrations of each gas become well mixed throughout the entire global atmosphere. Defining the air pollutant to be the combination of these six well-mixed greenhouse gases is based in part on this attribute—after the gases are emitted, they are sufficiently long-lived in the atmosphere to become well mixed as part of the air pollution.

[37] For section 202(a) source categories, only the hydrofluorocarbon emissions related to passenger compartment cooling are included. Emissions from refrigeration units that may be attached to trucks are considered emissions from nonroad engines under CAA section 213.

motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming.'' *Massachusetts v. EPA,* 549 U.S. at 525.[38]

1. Administrator's Approach in Making This Finding

Section 202(a) of the CAA source categories consist of passenger cars, light-duty trucks, motorcycles, buses, and heavy- and medium-duty trucks. As noted in the Proposed Findings, in the past the requisite contribution findings have been proposed concurrently with proposing emission standards for the relevant mobile source category. Thus, prior contribution findings often focused on a subset of the CAA section 202(a) (or other section) source categories. This final cause or contribute finding, however, is for all of the CAA section 202(a) source categories. The Administrator is considering emissions from all of these source categories in the determination.

Section 202(a) source categories emit the following well-mixed greenhouse gases: carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons. As the basis for the Administrator's determination, EPA analyzed historical data of emissions of the well-mixed greenhouse gases for motor vehicles and motor vehicle engines in the United States from 1990 to 2007.

The Proposed Findings discussed a number of possible ways of assessing cause or contribute and the point was made that no single approach is required by the statute or has been used exclusively in previous determinations under the CAA. The Administrator also discussed how, consistent with prior cause or contribute findings and the science, she is using emissions as a proxy for contributions to atmospheric concentrations. This approach is reasonable for the well-mixed greenhouse gases, because cumulative emissions are responsible for the cumulative change in the concentrations in the atmosphere. Similarly, annual emissions are a perfectly reasonable proxy for annual incremental changes in atmospheric concentrations.

In making a judgment about the contribution of emissions from CAA section 202(a) source categories, the Administrator focused on making a reasoned overall comparison of emissions from the CAA section 202(a) source categories to emissions from other sources of greenhouse gases. This allows a determination of how the CAA section 202(a) source categories compare to all of the other sources that together as a group make up the total emissions contributors to the air pollution problem. The relative importance of the CAA section 202(a) source categories is central to making the contribution determination. Both the magnitude of these emissions and the comparison of these emissions to other sources provide the basis to determine whether the CAA section 202(a) source categories may reasonably be judged as contributing to the air pollution problem.

In many cases EPA makes this kind of comparison of source categories by a simple percentage calculation that compares the emissions from the source category at issue to a larger total group of emissions. Depending on the circumstances, a larger percentage often means a greater relative impact from that source category compared to the other sources that make up the total of emissions, and vice versa. However, the actual numerical percentages may have little meaning when viewed in isolation. The context of the comparison is needed to ensure the information is useful in evaluating the relative impact of one source compared to others. For example, the number of sources involved and the distribution of emissions across all of the sources can make a significant difference when evaluating the results of a percentage calculation. In some cases a certain percentage might mean almost all other sources are larger or much larger than the source at issue, while in other circumstances the same percentage could mean that the source at issue is in fact one of the larger contributors to the total.

The Administrator therefore considered the totality of the circumstances in order to best understand the role played by CAA section 202(a) source categories. This is consistent with Congress' intention for EPA to consider the cumulative impact of all sources of pollution. In that context, the global nature of the air pollution problem and the breadth of countries and sources emitting greenhouse gases means that no single country and no single source category dominate or are even close to dominating on a global scale. For example, the United States as a country is the second largest emitter of greenhouse gases, and emits approximately 18 percent of the world's total greenhouse gases. The total emissions of greenhouse gases worldwide are from numerous sources and countries, with each country and each source category contributing a relatively small percentage of the total emissions. That means that the relative ranking of countries or sources is not at all obvious from the magnitude of the percentage by itself. A country or a source may be a large contributor, in comparison to other countries or sources, even though its percentage contribution may appear relatively small.

In this situation, addressing a global air pollution problem may call for many different sources and countries to address emissions even if none by itself dominates or comes close to dominating the global inventory. A somewhat analogous situation can be found in the ozone air pollution problem in the United States. Emissions of NOx and volatile organic compounds (VOCs) often come from numerous small sources, as well as certain large source categories. We have learned that successful ozone control strategies often need to take this into account, and address both the larger sources of NOx and VOCs as well as the many smaller sources, given the breadth of sources that as a group lead to the total inventory of VOCs and NOx.

The global aspects of the greenhouse gas air pollution problem amplify this kind of situation many times over, where no single country or source category dominates or comes close to dominating the global inventory of greenhouse gas emissions. These unique, global aspects of the climate change problem tend to support consideration of contribution at lower percentage levels of emissions than might otherwise be considered appropriate when addressing a more typical local or regional air pollution problem. In this situation it is quite reasonable to consider emissions from source categories that are more important in relation to other sources, even if their absolute contribution initially may appear to be small.

In addition, the Administrator is aware of the fact that the United States is the second largest emitter of well-mixed greenhouse gases in the world. As the United States evaluates how to address climate change, the Administrator will analyze the various sources of emissions and the source's share of U.S. emissions. Thus, when analyzing whether a source category that emits well-mixed greenhouse gases in the United States contributes to the global problem, it is appropriate for the Administrator to consider how that source category fits into the larger picture of U.S. emissions. This ranking process within the United States allows the importance of the source category to

[38] Because the Administrator is defining the air pollutant as the combination of well-mixed greenhouse gases, she is not issuing a final contribution finding based on the alternative definition discussed in the proposed findings (*e.g.*, each greenhouse gas as an individual air pollutant).

be seen compared to other U.S. sources, informing the judgment of the importance of emissions from this source category in any overall national strategy to address greenhouse gas emissions.

It is in this broader context that EPA considered the contribution of CAA section 202(a) sources. This provides useful information in determining the importance that should be attached to the emissions from the CAA section 202(a) sources.

In reaching her determination, the Administrator used two simple and straightforward comparisons to assess cause or contribute for CAA section 202(a) source categories: (1) As a share of total current global aggregate emissions of the well-mixed greenhouse gases; and (2) as a share of total current U.S. aggregate emissions of the well-mixed greenhouse gases.

Total well-mixed greenhouse gas emissions from CAA section 202(a) source categories were compared to total global emissions of the well-mixed greenhouse gases. The total air pollution problem, as already discussed, is the elevated and climbing levels of the six greenhouse gas concentrations in the atmosphere, which are global in nature because these concentrations are globally well mixed (whether they are emitted from CAA section 202(a) source categories or any other source within or outside the United States). In addition, comparisons were also made to U.S. total well-mixed greenhouse gases emissions to appreciate how CAA section 202(a) source categories fit into the larger U.S. contribution to the global problem. It is typical for the Administrator to consider these kinds of comparisons of emissions of a pollutant in evaluating contribution to air pollution, such as the concentrations of that same pollutant in the atmosphere (*e.g.,* the Administrator analyzes $PM_{2.5}$ emissions to determine if a source category contributes to $PM_{2.5}$ air pollution). When viewed in the circumstances discussed above, both of these comparisons provide useful information in determining whether these source categories should be judged as contributing to the total air pollution problem.

a. Section 202(a) of the CAA—Share of Global Aggregate Emissions of the Well-Mixed Greenhouse Gases

Global emissions of well-mixed greenhouse gases have been increasing, and are projected to continue increasing unless the major emitters take action to reduce emissions. Total global emissions of well-mixed greenhouse gases in 2005 (the most recent year for which data for all countries and all greenhouse gases are available) [39] were 38,726 teragrams of CO_2-equivlant ($TgCO_2$eq.) [40] This represents an increase in global greenhouse gas emissions of about 26 percent since 1990 (excluding land use, land use change and forestry). In 2005, total U.S. emissions of well-mixed greenhouse gases were responsible for 18 percent of global emissions, ranking only behind China, which was responsible for 19 percent of global emissions of well-mixed greenhouse gases.

In 2005 emissions of the well-mixed greenhouse gas pollutant from CAA section 202(a) source categories represented 4.3 percent of total global well-mixed greenhouse gas emissions and 28 percent of global transport well-mixed greenhouse gas emissions (Table 1 of these Findings). If CAA section 202(a) source categories' emissions of well-mixed greenhouse gas were ranked against total well-mixed greenhouse gas emissions for entire countries, CAA section 202(a) source category emissions would rank behind only China, the United States as a whole, Russia, and India, and would rank ahead of Japan, Brazil, Germany and every other country in the world. Indeed, countries with lower emissions than the CAA section 202(a) source categories are members of the 17 ''major economies'' ''that meet to advance the exploration of concrete initiatives and joint ventures that increase the supply of clean energy while cutting greenhouse gas emissions.'' *See http://www.state.gov/g/oes/climate/mem/*. It would be anomalous, to say the least, to consider Japan and these other countries as major players in the global climate change community and an integral part of the solution, but not find that CAA section 202(a) source category emissions contribute to the global problem. Thus, the Administrator finds that emission of well-mixed greenhouse gases from CAA section 202(a) source categories contribute to the air pollution of well-mixed greenhouse gases.

TABLE 1—COMPARISON TO GLOBAL GREENHOUSE GAS (GHG) EMISSIONS (TG CO_2E)

	2005	Sec 202(a) share (percent)
All U.S. GHG emissions	7,109	23.5
Global transport GHG emissions	5,968	28.0
All global GHG emissions	38,726	4.3

b. Section 202(a) of the CAA—Share of U.S. Aggregate Emissions of the Well-Mixed Greenhouse Gases

The Administrator considered compared total emissions of the well-mixed greenhouse gases from CAA section 202(a) source categories to total U.S. emissions of the well-mixed greenhouse gases as an indication of the role these sources play in the total U.S. contribution to the air pollution problem causing climate change.[41]

In 2007, U.S. well-mixed greenhouse gas emissions were 7,150 $TgCO_2$eq. The dominant gas emitted was carbon dioxide, mostly from fossil fuel combustion. Methane was the second largest well-mixed greenhouse gas, followed by N_2O, and the fluorinated gases (HFCs, PFCs, and SF_6). Electricity generation was the largest emitting sector (2,445 $TgCO_2$eq or 34 percent of

[39] The source of global greenhouse gas emissions data, against which comparisons are made, is the Climate Analysis Indicators Tool of the World Resources Institute (WRI) (2007). Note that for global comparisons, all emissions are from the year 2005, the most recent year for which data for all greenhouse gas emissions and all countries are available. WRI (2007) Climate Analysis Indicators Tool (CAIT). Available at *http://cait.wri.org*. Accessed August 5, 2009.

[40] One teragram (Tg) = 1 million metric tons. 1 metric ton = 1,000 kg = 1.102 short tons = 2,205 lbs. Long-lived greenhouse gases are compared and summed together on a CO_2 equivalent basis by multiplying each gas by its Global Warming Potential (GWPs), as estimated by IPCC. In accordance with UNFCCC reporting procedures, the U.S. quantifies greenhouse gas emissions using the 100-year time frame values for GWPs established in the IPCC Second Assessment Report.

[41] Greenhouse gas emissions data for the United States in this section have been updated since the Proposed Findings to reflect EPA's most up-to-date information, which includes data for the year 2007. The source of the U.S. greenhouse gas emissions data is the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2007,* published in 2009 (hereinafter ''U.S. Inventory'').

total U.S. greenhouse gas emissions), followed by transportation (1,995 $TgCO_2eq$ or 28 percent) and industry (1,386 $TgCO_2eq$ or 19 percent). Emissions from the CAA section 202(a) source categories constitute the major part of the transportation sector. Land use, land use change, and forestry offset almost 15 percent of total U.S. emissions through net sequestration. Total U.S. well-mixed greenhouse gas emissions have increased by over 17 percent between 1990 and 2007. The electricity generation and transportation sectors have contributed the most to this increase.

In 2007 emissions of well-mixed greenhouse gases from CAA section 202(a) source categories collectively were the second largest emitter of well-mixed greenhouse gases within the United States (behind the electricity generating sector), emitting 1,663 $TgCO_2eq$ and representing 23 percent of total U.S. emissions of well-mixed greenhouse gases (Table 2 of these Findings). The Administrator is keenly aware that the United States is the second largest emitter of well-mixed greenhouse gases. Part of analyzing whether a sector within the United States contributes to the global problem is to see how those emissions fit into the contribution from the United States as a whole. This informs her judgment as to the importance of emissions from this source category in any overall national strategy to address greenhouse gas emissions. Thus, it is relevant that CAA section 202(a) source categories are the second largest emitter of well-mixed greenhouse gases in the country. This is part of the Administrator looking at the totality of the circumstances. Based on this the Administrator finds that emission of well-mixed greenhouse gases from CAA section 202(a) source categories contribute to the air pollution of well-mixed greenhouse gases.

TABLE 2—SECTORAL COMPARISON TO TOTAL U.S. GREENHOUSE GAS (GHG) EMISSIONS (TG CO_2E)

U.S. emissions	1990	1995	2000	2005	2006	2007
Section 202(a) GHG emissions	1231.9	1364.4	1568.1	1670.5	1665.7	1663.1
Share of U.S. (%)	20.2%	21.1%	22.4%	23.5%	23.6%	23.3%
Electricity Sector emissions	1859.1	1989.0	2329.3	2429.4	2375.5	2445.1
Share of U.S. (%)	30.5%	30.8%	33.2%	34.2%	33.7%	34.2%
Industrial Sector emissions	1496.0	1524.5	1467.5	1364.9	1388.4	1386.3
Share of U.S. (%)	24.5%	23.6%	20.9%	19.2%	19.7%	19.4%
Total U.S. GHG emissions	6098.7	6463.3	7008.2	7108.6	7051.1	7150.1

C. Response to Key Comments on the Administrator's Cause or Contribute Finding

EPA received numerous public comments regarding the Administrator's proposed cause or contribute finding. Below is a brief discussion of some of the key comments. Responses to comments on this issue are also contained in the Response to Comments document, Volume 10.

1. The Administrator Reasonably Defined the ''Air Pollutant'' for the Cause or Contribute Analysis

a. The Supreme Court Held that Greenhouse Gases Fit Within the Definition of ''Air Pollutant'' in the CAA

Several commenters reiterate arguments already rejected by the Supreme Court, arguing that greenhouse gases do not fit into the definition of ''air pollutant'' under the CAA. In particular, at least one commenter contends that EPA must show how greenhouse gases impact or materially change ''ambient air'' when defining air pollutant and making the endangerment finding. This commenter argues that because carbon dioxide is a naturally occurring and necessary element in the atmosphere, it cannot be considered to materially change air.

These and similar arguments were already rejected by the Supreme Court in *Massachusetts* v. *EPA*, 549 U.S. 497 (2007). Briefs before the Supreme Court also argued that carbon dioxide is an essential role for life on earth and therefore cannot be considered an air pollutant, and that the concentrations of greenhouse gases that are a potential problem are not in the ''ambient air'' that people breathe.

The Court rejected all of these and other arguments, noting that the statutory text forecloses these arguments. ''The Clean Air Act's sweeping definition of 'air pollutant' includes '*any* air pollution agent or combination of such agents, including *any* physical, chemical * * * substance or matter which is emitted into or otherwise enters the ambient air . * * *' § 7602(g) (emphasis added). On its face, the definition embraces all airborne compounds of whatever stripe, and underscores that intent through the repeated use of the word 'any.' Carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons are without a doubt 'physical [and] chemical * * * substance[s] which [are] emitted into * * * the ambient air.' The statute is unambiguous.''

547 U.S. at 529–30 (footnotes omitted); see also *id.* at 530, n26 (the distinction regarding ambient air, however, finds no support in the text of the statute, which uses the phrase ''the ambient air'' without distinguishing between atmospheric layer.). Thus, the question of whether greenhouse gases fit within the definition of air pollutant under the CAA has been decided by the Supreme Court and is not being revisited here.

b. The Definition of Air Pollutant May Include Substances Not Emitted by CAA Section 202(a) Sources

Many commenters argue that the definition of ''air pollutant''—here well-mixed greenhouse gases—cannot include PFCs and SF6 because they are not emitted by CAA section 202(a) motor vehicles and hence, cannot be part of any ''air pollutant'' emitted by such sources. They argue that by improperly defining ''air pollutant'' to include substances that are not present in motor vehicle emissions, the Agency has exceeded its statutory authority under CAA section 202(a). Commenters contend that past endangerment findings under CAA section 202(a) demonstrate EPA's consistent approach of defining ''air pollutant(s)'' in accordance with the CAA's clear direction, to include only those pollutants emitted from the relevant source category (citing Notice of Proposed Rulemaking for Heavy-Duty Engine and Vehicle Standards finding that ''emissions of NO_X, VOCs, SO_X, and PM from heavy-duty trucks can reasonably be anticipated to endanger the public health or welfare.'' (65 FR 35436, June 2, 2000). Commenters argue that EPA itself is inconsistent in the Proposed Findings, sometimes referring to ''air pollutant'' as the group of six greenhouse gases, and other times falling back on the four greenhouse gases emitted by motor vehicles.

EPA acknowledges that the Proposed Findings could have been clearer regarding the proposed definition of air pollutant, and how it was being applied to CAA section 202(a) sources, which emit only four of the six substances that meet the definition of well-mixed greenhouse gases. However, our interpretation does not exceed EPA's authority under CAA section 202(a). It is reasonable to define the air pollutant under CAA section 202(a) to include substances that have similar attributes (as discussed above), even if not all of the substances that meet that definition are emitted by motor vehicles. For example, as commenters note, EPA has heavy duty truck standards applicable to VOCs and PM, but it is highly unlikely that heavy duty trucks emit *every* substance that is included in the group defined as VOC or PM. *See* 40 CFR 51.100(s) (defining volatile organic compound (VOC) as ''any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions'', a list of exemptions are also included in the definition); 40 CFR 51.100(oo) (defining particulate matter (PM) as ''any airborne finely divided solid or liquid material with an aerodynamic diameter smaller than 100 micrometers'').

In this circumstance the number of substances included in the definition of well-mixed greenhouse gases is much smaller than other ''group'' air pollutants (*e.g.,* six greenhouse gases versus hundreds of VOCs), and CAA section 202(a) sources emit an easily discernible number of these six substances. However, this does not mean that the definition of the well-mixed greenhouse gases as the air pollutant is unreasonable. By defining well-mixed greenhouse gases as a single air pollutant comprised of six substances with common attributes, the Administrator is giving effect to these shared attributes and how they are relevant to the air pollution to which they contribute. The fact that these six substances share these common, relevant attributes is true regardless of the source category being evaluated for contribution. Grouping these six substances as one air pollutant is reasonable regardless of whether a contribution analysis is undertaken for CAA section 202(a) sources that emit one subset of the six substances (*e.g.*, carbon dioxide, CH_4, N_20 and HFCs, but not PFCs and SF_6), or for another category of sources that may emit another subset. For example, electronics manufacturers that may emit N_2O, PFCs, HFCs, SF_6 and other fluorinated compounds, but not carbon dioxide or CH_4 unless there is on-site fuel combustion. In other words, it is not necessarily the source category being evaluated for contribution that determines the reasonableness of defining a group air pollutant based on the shared attributes of the group.

Even if EPA agreed with commenters, and defined the air pollutant as the group of four compounds emitted by CAA section 202(a) sources, it would not change the result. The Administrator would make the same contribution finding as it would have no material effect on the emissions comparisons discussed above.

c. It Was Reasonable for the Administrator To Define the Single Air Pollutant as the Group of Substances With Common Attributes

Several commenters disagree with EPA's proposed definition of a single air pollutant composed of the six well-mixed greenhouse gases as a class. Commenters argue that the analogy to VOCs is misplaced because VOCs are all part of a defined group of chemicals, for which there are established quantification procedures, and for which there were extensive data showing that the group of compounds had demonstrated and quantifiable effects on ambient air and human health and welfare, and for which verifiable dispersion models existed. They contend this is in stark contrast to the entirely diverse set of organic and inorganic compounds EPA has lumped together for purposes of the Proposed Findings, and for which no model can accurately predict or quantify the actual impact or improvement resulting from controlling the compounds. Moreover, they argue that the gases EPA is proposing to list together as one pollutant are all generated by different processes and, if regulated, would require different types of controls; the four gases emitted by mobile sources can generally be limited only by using controls that are specific to each.

At least one commenter argues that EPA cannot combine greenhouse gases into one pollutant because their common attribute is not a ''physical, chemical, biological or radioactive property'' (quoting from CAA section 302(g)), but rather their effect or impacts on the environment. They say this differs from VOCs, which share the common attribute of volatility, or PM which shares the physical property of being particles.

As discussed above, the well-mixed greenhouse gases share physical attributes, as well as attributes based on sound policy considerations. The definition of ''air pollutant'' in CAA section 302(g) does not limit consideration of common attributes to those that are ''physical, chemical, biological or radioactive property'' as one commenter claims. Rather, the definition's use of the adjectives ''physical, chemical, biological or radioactive'' refer to the different types of substance or matter that is emitted. It is not a limitation on what characteristics the Administrator may consider when deciding how to group similar substances when defining a single air pollutant.

The common attributes that the Administrator considered when defining the well-mixed greenhouse gases are reasonable. While these six substances may originate from different processes, and require different control strategies, that does not detract from the fact that they are all long-lived, well-mixed in the atmosphere, directly emitted, of well-known radiative forcing, and generally grouped and considered together in climate change scientific and policy forums. Indeed, other group pollutants also originate from a variety of processes and a result may require different control technologies. For example, both a power plant and a dirt road can result in PM emissions, and the method to control such emissions at each source would be different. But these differences in origin or control do not undermine the reasonableness of considering PM as a single air pollutant. The fact that there are differences, as well as similarities, among the well-mixed greenhouse gases does not render the decision to group them together as one air pollutant unreasonable.

2. The Administrator's Cause or Contribute Analysis Was Reasonable

a. The Administrator Does Not Need To Find Significant Contribution, or Establish a Bright Line

Many commenters essentially argue that EPA must establish a bright line below which it would never find contribution regardless of the air pollutant, air pollution, and other factors before the Agency. For example, some commenters argue that EPA must provide some basis for determining de minimis amounts that fall below the threshold of ''contributing'' to the endangerment of public health and welfare under CAA section 202(a).

Commenters take issue with EPA's statement that it ''need not determine at this time the circumstances in which emissions would be trivial or de minimis and would not warrant a finding of contribution.'' Commenters argue that EPA cannot act arbitrarily by determining that a constituent contributing a certain percent to endangerment in one instance is de minimis and in another is contributing to endangerment of public health and welfare. They request that EPA revise the preamble language to make clear that the regulated community can rely on its past determinations with respect to ''contribution'' determinations to predict future agency action and argue that EPA should promulgate guidance on how it determines whether a contribution exceeds a de minimis level for purposes of CAA section 202(a) before finalizing the proposal.

The commenters that argue that the air pollution EPA must analyze to determine endangerment is limited to the air pollution resulting from new motor vehicles also argue that as a result, the contribution of emissions from new motor vehicles must be significant. They essentially contend that the endangerment and cause or contribute tests are inter-related and the universe of both tests is the same. In support of their argument, commenters argue that because the clause ''cause, or contribute to, air pollution'' is in plural form, it must be referring back to ''any class or classes of new motor vehicles or new motor vehicle engines,'' demonstrating that EPA must consider only the emissions from new motor vehicles which emit the air pollution which endangers.

Since the Administrator issued the Proposed Findings, the DC Circuit issued another opinion discussing the concept of contribution. See *Catawba County* v. *EPA*, 571 F.3d 20 (DC Cir. 2009). This decision, along with others, supports the Administrator's interpretation that the level of contribution under CAA section 202(a) does not need to be significant. The Administrator is not required to establish a bright line below which she would never find contribution under any circumstances. Finally, it is reasonable for the Administrator to apply a ''totality-of-the-circumstances test to implement a statute that confers broad discretionary authority, even if the test lacks a definite 'threshold' or 'clear line of demarcation to define an open-ended term.'' *Id.* at 39 (citations omitted).

In upholding EPA's $PM_{2.5}$ attainment and nonattainment designation decisions, the DC Circuit analyzed CAA section 107(d), which requires EPA to designate an area as nonattainment if it ''contributes to ambient air quality in a nearby area'' not attaining the national ambient air quality standards. *Id.* at 35. The court noted that it had previously held that the term ''contributes'' is ambiguous in the context of CAA language. *See EDF* v. *EPA*, 82 F.3d 451, 459 (DC Cir. 1996). ''[A]mbiguities in statutes within an agency's jurisdiction to administer are delegations of authority to the agency to fill the statutory gap in reasonable fashion.'' 571 F.3d at 35 (citing *Nat's Cable & Telecomms. Ass'c* v. *Brand X Internet Servs,* 545 U.S. 967, 980 (2005)).

The court then proceeded to consider and reject petitioners' argument that the verb ''contributes'' in CAA section 107(d) necessarily connotes a significant causal relationship. Specifically, the DC Circuit again noted that the term is ambiguous, leaving it to EPA to interpret in a reasonable manner. In the context of this discussion, the court noted that ''a contribution may simply exacerbate a problem rather than cause it * * * '' 571 F.3d at 39. This is consistent with the DC Circuit's decision in *Bluewater Network* v. *EPA,* 370 F.3d 1 (DC Cir. 2004), in which the court noted that the term contribute in CAA section 213(a)(3) ''[s]tanding alone, * * * has no inherent connotation as to the magnitude or importance of the relevant 'share' in the effect; certainly it does not incorporate any 'significance' requirement.'' 370 F.3d at 13. The court found that the bare ''contribute'' language invests the Administrator with discretion to exercise judgment regarding what constitutes a sufficient contribution for the purpose of making an endangerment finding. *Id.* at 14.

Finally, in *Catawba County,* the DC Circuit also rejected ''petitioners' argument that EPA violated the statute by failing to articulate a quantified amount of contribution that would trigger'' the regulatory action. 571 F.3d at 39. Although petitioners preferred that EPA establish a bright-line test, the court recognized that the statute did not require that EPA ''quantify a uniform amount of contribution.'' *Id.*

Given this context, it is entirely reasonable for the Administrator to interpret CAA section 202(a) to require some level of contribution that, while more than de minimis or trivial, does not rise to the level of significance. Moreover, the approach suggested by at least one commenter collapses the two prongs of the test by requiring that contribution must be significant because any climate change impacts upon which an endangerment determination is made result solely from the greenhouse gas emissions of motor vehicles. It essentially eliminates the ''contribute'' part of the ''cause or contribute'' portion of the test. This approach was clearly rejected by the en banc court in *Ethyl.* 541 F.2d at 29 (rejecting the argument that the emissions of the fuel additive to be regulated must ''in and of itself, *i.e.* considered in isolation, endanger[ ] public health.''); see also *Catawba County,* 571 F.3d at 39 (noting that even if the test required significant contribution it would be reasonable for EPA to find a county's addition of $PM_{2.5}$ is significant even though the problem would persist in its absence). It is the commenter, not EPA that is ignoring the statutory language. Whether or not the clause ''cause, or contribute to, air pollution'' refers back to ''any class or classes of new motor vehicles or new motor vehicle engines,'' or to ''emission of any air pollutant,'' the language of CAA section 202(a) clearly contemplates that emission of an air pollutant from any class or classes may merely contribute to, versus cause, the air pollution which endangers.

It is also reasonable for EPA to decline to establish a ''bright-line 'objective' test of contribution.'' 571 F.3d at 39. As noted in the Proposed Findings, when exercising her judgment, the Administrator not only considers the cumulative impact, but also looks at the totality of the circumstances (*e.g.,* the air pollutant, the air pollution, the nature of the endangerment, the type of source category, the number of sources in the source category, and the number and type of other source categories that may emit the air pollutant) when determining whether the emissions justify regulation under the CAA. *Id.* (It is reasonable for an agency to adopt a totality-of-the-circumstances test).

Even if EPA agreed that a level of significance was required to find contribution, for the reasons discussed above, EPA would find that the contribution from CAA section 202(a) source categories is significant. Their emissions are larger than the great majority of emitting countries, larger than several major emitting countries, and they constitute one of the largest parts of the U.S. emissions inventory.

b. The Unique Global Aspects of Climate Change Are an Appropriate Consideration in the Contribution Analysis

Some commenters disagree with statements in the Proposed Findings that the ''unique, global aspects of the climate change problem tend to support a finding that lower levels of emissions should be considered to contribute to the air pollution than might otherwise be appropriate when considering contribution to a local or regional air pollution problem.'' They argue there is no basis in the CAA or existing EPA policy for this position, and that it reveals an apparent effort to expand EPA's authority to the ''truly trivial or de minimis'' sources that are acknowledged to be outside the scope of regulation, in that it expands EPA's authority to regulate pollutants to address global effects.

Commenters also assert that contrary to EPA's position, lower contribution numbers are appropriate when looking at local pollution, like nonattainment concerns—in other words, in the context of a statutory provision like CAA section 213 specifically aimed at targeting small source categories to help nonattainment areas meet air quality standards. However, they conclude this policy is simply inapplicable in the context of global climate change.

As discussed above, the term ''contribute'' is ambiguous and subject to the Administrator's reasonable interpretation. It is entirely appropriate for the Administrator to look at the totality of the circumstances when making a finding of contribution. In this case, the Administrator believes that the global nature of the problem justifies looking at contribution in a way that takes account of these circumstances. More specifically, because climate change is a global problem that results from global greenhouse gas emissions, there are more sources emitting greenhouse gases (in terms both of absolute numbers of sources and types of sources) than EPA typically encounters when analyzing contribution towards a more localized air pollution problem. From a percentage perspective, there are no dominating sources and fewer sources that would even be considered to be close to dominating. The global problem is much more the result of numerous and varied sources each of which emit what might seem to be smaller percentage amounts when compared to the total. The Administrator's approach recognizes this reality, and focuses on evaluating the relative importance of the CAA section 202(a) source categories compared to other sources when viewed in this context.

This recognition of the unique totality of the circumstances before the Administrator now as compared to previous contribution decisions is entirely appropriate. It is not an attempt by the Administrator to regulate ''truly trivial or de minimis'' sources, or to regulate sources based on their global effects. The Administrator is determining whether greenhouse gas emissions from CAA section 202(a) sources contribute to an air pollution problem is endangering U.S. public health and welfare. As discussed in the Proposed Findings, no single greenhouse gas source category dominates on the global scale, and many (if not all) individual greenhouse gas source categories could appear small in comparison to the total, when, in fact, they could be very important contributors in terms of both absolute emissions or in comparison to other source categories, globally or within the United States. If the United States and the rest of the world are to combat the risks associated with global climate change, contributors must do their part even if their contributions to the global problem, measured in terms of percentage, are smaller than typically encountered when tackling solely regional or local environmental issues. The commenters' approach, if used globally, would effectively lead to a tragedy of the commons, whereby no country or source category would be accountable for contributing to the global problem of climate change, and nobody would take action as the problem persists and worsens. The Administrator's approach, on the contrary, avoids this kind of approach, and is a reasonable exercise of her discretion to determine contribution in the global context in which this issue arises.

Importantly, as discussed above, the contribution from CAA section 202(a) sources is anything but trivial or de minimis under any interpretation of contribution. See, *Massachusetts v. EPA,* 549 U.S. at 1457–58 (''Judged by any standard, U.S. motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming'').

c. The Administrator Reasonably Relied on Comparisons of Emissions From Existing CAA Section 202(a) Source Categories

i. It Was Reasonable To Use Existing Emissions From Existing CAA Section 202(a) Source Categories Instead of Projecting Future Emissions From New CAA Section 202(a) Source Categories

Many commenters argue that EPA improperly evaluated the emissions from the entire motor vehicle fleet, and it is required to limit its calculation to just emissions from new motor vehicles. Thus the emissions that EPA should consider in the cause or contribute determination is far less than the 4.3 percent of U.S. greenhouse gas emissions attributed to motor vehicles in the Proposed Findings, because this number includes both new and existing motor vehicles. One commenter calculated the emissions from new motor vehicles as being 1.8 percent of global emissions, assuming approximately one year of new motor vehicle production in the United States (11 million vehicles) in a total global count currently of approximately 600 million motor vehicles.

In the Proposed Findings, EPA determined the emissions from the entire fleet of motor vehicles in the United States for a certain calendar year. EPA explained that, consistent with its traditional practice, it used the recent motor vehicle emissions inventory for the entire fleet as a surrogate for estimates of emissions for just new motor vehicles and engines. This was appropriate because future projected emissions are uncertain and current emissions data are a reasonable proxy for near-term emissions.

In effect, EPA is using the inventory for the current fleet of motor vehicles as a reasonable surrogate for a projection of the inventory from new motor vehicles over the upcoming years. New motor vehicles are produced year in and year out, and over time the fleet changes over to a fleet composed of such vehicles. This occurs in a relatively short time frame, compared to the time period at issue for endangerment. Because new motor vehicles are produced each year, and continue to emit over their entire life, over a relatively short period of time the emission from the entire fleet is from vehicles produced after a certain date. In addition, the emissions from new motor vehicles are not limited to the emissions that occur only during the one year when they are new, but are emissions over the entire life of the vehicle.

In such cases, EPA has traditionally used the recent emissions from the entire current fleet of motor vehicles as a reasonable surrogate for such a projection instead of trying to project and model those emissions. While this introduces some limited degree of uncertainty, the difference between recent actual emissions from the fleet and projected future emissions from the fleet is not expected to differ in any way that would substantively change the decision made concerning cause or contribution. There is not a specific numerical bright line that must be achieved, and the numerical percentages are not treated and do not need to be treated as precise values. This approach provides a reasonable and clear indication of the relative magnitudes involved, and EPA does not believe that attempting to make future projections (for both vehicles and the emissions value they are compared to) would provide any greater degree of accuracy or precision in developing such a relative comparison.

ii. The Administrator Did Not Have To Use a Subset or Reduced Emissions Estimate From Existing CAA Section 202(a) Source Categories

Several commenters note that although EPA looks at emissions from all motor vehicles regulated under CAA section 202(a) in its contribution analysis, the Presidential announcement in May 2009 indicated that EPA was planning to regulate only a subset of 202(a) sources. Thus, they question whether the correct contribution analysis should look only at the emissions from that subset and not all CAA section 202(a) sources. Some commenters also argue that because emission standards will not eliminate all greenhouse gas emissions from motor vehicles, the comparison should compare the amount of greenhouse gas emissions ''reduced'' by those standards to the global greenhouse emissions. They also contend that the cost of the new standards will cause individual consumers, businesses, and other vehicle purchasers to hold on to their existing vehicles to a greater extent, thereby decreasing the amount of emissions reductions attributable to the standard and appropriately considered in the contribution analysis. Some commenters go further and contend that EPA also can only include that incremental reduction that the EPA regulations will achieve beyond any reductions resulting from CAFE standards that NHTSA will set.

Although the May announcement and September proposed rule involved only the light duty motor vehicle sector, the Administrator is making this finding for all classes of new motor vehicles under CAA section 202(a). Thus, although the announcement and proposed rule involve light duty vehicles, EPA is working to develop standards for the rest of the classes of new motor vehicles under CAA section 202(a). As the Supreme Court noted, EPA has ''significant latitude as to the manner, timing, content, and coordination of its regulations with those of other agencies. *Massachusetts* v. *EPA,* 549 U.S. at 533.

The argument that the Administrator can only look at that portion of emissions that will be reduced by any CAA section 202(a) standards, and even then only the reduction beyond those attributable to CAFE rules, finds no basis in the statutory language. The language in CAA section 202(a) requires that the Administrator set ''standards applicable to the emission of any air pollutant from [new motor vehicles], which in [her] judgment cause, or contribute to, air pollution which [endangers].'' It does not say set ''standards applicable to the emission of any air pollutant from [new motor vehicles], if in [her] judgment the emissions of that air pollutant as reduced by that standard cause, or contribute to, air pollution which [endangers].'' As discussed above, the decisions on cause or contribute and endangerment are separate and distinct from the decisions on what emissions standards to set under CAA section 202(a). The commenter's approach would improperly integrate these separate decisions. Indeed, because, as discussed above, the Administrator does not have to propose standards concurrent with the endangerment and cause or contribute findings, she would have to be prescient to know at the time of the contribution finding exactly the amount of the reduction that would be achieved by the standards to be set. As discussed above, for purposes of these findings we look at what would be the emissions from new motor vehicles if no action were taken. Current emissions from the existing CAA section 202(a) vehicle fleet are an appropriate estimate.

d. The Administrator Reasonably Compared CAA Section 202(a) Source Emissions to Both Global and Domestic Emissions of Well-Mixed Greenhouse Gases

EPA received many comments on the appropriate comparison(s) for the contribution analysis. Several commenters argue that in order to get around the ''problem'' of basing an endangerment finding upon a source category that contributes only 1.8 percent annually to global greenhouse gas emissions, EPA inappropriately also made comparisons to total U.S. greenhouse gas emissions. These commenters argue that a comparison of CAA section 202(a) source emissions to U.S. greenhouse gas emissions, versus global emissions, is arbitrary for purposes of the cause or contribute analysis, because it conflicts with the Administrator's definition of ''air pollution,'' as well as the nature of global warming. They note that throughout the Proposed Findings, the Administrator focuses on the global nature of greenhouse gas. Thus, they continue, while the percentage share of motor vehicle emissions at the U.S. level may be relevant for some purposes, it is irrelevant to a finding of whether these emissions contribute to the air pollution, which the Administrator has proposed to define on a global rather than a domestic basis. Commenters also accuse EPA of arbitrarily picking and choosing when it takes a global approach (*e.g.,* endangerment finding) and when it does not (*e.g.,* contribution findings).

The language of CAA section 202(a) is silent regarding how the Administrator is to make her contribution analysis. While it requires that the Administrator assess whether emission of an air pollutant contributes to air pollution which endangers, it does not limit *how* she may undertake that assessment. It surely is reasonable that the Administrator look at how CAA section 202(a) source category emissions compare to global emissions on an absolute basis, by themselves. But the United States as a nation is the second largest emitter of greenhouse gases. It is entirely appropriate for the Administrator to decide that part of understanding how a U.S. source category emitting greenhouse gases fits into the bigger picture of global climate change is to appreciate how that source category fits into the contribution from the United States as a whole, where the United States as a country is a major emitter of greenhouse gases. Knowing that CAA section 202(a) source categories are the second largest emitter of well-mixed greenhouse gases in the country is relevant to understanding what role they play in the global problem and hence whether they ''contribute'' to the global problem. Moreover, the Administrator is not ''picking and choosing'' when she applies a global or domestic approach in these Findings. Rather, she is looking at both of these emissions comparisons as appropriate under the applicable science, facts, and law.

e. The Amount of Well-Mixed Greenhouse Gas Emissions From CAA Section 202(a) Sources Reasonably Supports a Finding of Contribution

Many commenters argue that the ''cause or contribute'' prong of the Proposal's endangerment analysis fails to satisfy the applicable legal standard, which requires more than a minimal contribution to the ''air pollution reasonably anticipated to endanger public health or welfare.'' They contend that emissions representing approximately four percent of total global greenhouse gas emissions are a minimal contribution to global greenhouse gas concentrations.

EPA disagrees. As stated above, CAA section 202(a) source category total emissions of well-mixed greenhouse gases are higher than most countries in the world; countries that the U.S. and others believe play a major role in the global climate change problem. Moreover, the percent of global well-mixed greenhouse gas emissions that CAA section 202(a) source categories represent is higher than percentages that the EPA has found contribute to air pollution problems. *See Bluewater Network,* 370 F.3d at 15 (''For Fairbanks, this contribution was equivalent to 1.2 percent of the total daily CO inventory for 2001.'') As noted above, there is no bright line for assessing contribution, but as discussed in the Proposed Findings and above, when looking at a global problem like climate change, with many sources of emissions and no dominating sources from a global perspective, it is reasonable to consider that lower percentages contribute than one may consider when looking at a local or regional problem involving fewer sources of emissions. The Administrator agrees that ''[j]udged by any standard, U.S. motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming.'' *Massachusetts v. EPA,* 549 U.S. at 525.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is a ''significant regulatory action'' because it raises novel policy issues. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to Office of Management and Budget (OMB) recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* Burden is defined at 5 CFR 1320.3(b). These Findings do not impose an information collection request on any person.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this action on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Because these Findings do not impose any requirements, the Administrator certifies that this action will not have a significant economic impact on a substantial number of small entities. This action does not impose any requirements on small entities. The endangerment and cause or contribute findings do not in-and-of-themselves impose any new requirements but rather set forth the Administrator's determination on whether greenhouse gases in the atmosphere may reasonably be anticipated to endanger public health or welfare, and whether emissions of greenhouse gases from new motor vehicles and engines contribute to this air pollution. Accordingly, the action affords no opportunity for EPA to fashion for small entities less burdensome compliance or reporting requirements or timetables or exemptions from all or part of the Findings.

D. Unfunded Mandates Reform Act

This action contains no Federal mandates under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for State, local, or tribal governments or the private sector. The action imposes no enforceable duty on any State, local or tribal governments or the private sector. Therefore, this action is not subject to the requirements of sections 202 or 205 of the UMRA.

This action is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This finding does not impose any requirements on industry or other entities.

E. Executive Order 13132: Federalism

This action does not have federalism implications. Because this action does not impose requirements on any entities, it will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this action.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). This action does not have substantial direct effects on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, nor does it impose any enforceable duties on any Indian tribes. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks. Although the Administrator considered health and safety risks as part of these Findings, the Findings themselves do not impose a standard intended to mitigate those risks.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy because it does not impose any requirements.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 104–113, 12(d) (15 U.S.C. at 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (EO) 12898 (59 FR 7629, Feb. 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that these Findings will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. Although the Administrator considered climate change risks to minority or low-income populations as part of these Findings, this action does not impose a standard intended to mitigate those risks and does not impose requirements on any entities.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective January 14, 2010.

Dated: December 7, 2009.

Lisa P. Jackson,

Administrator.

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Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements

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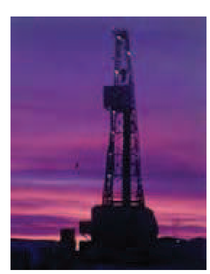


1.0 EXECUTIVE SUMMARY

Natural gas production in the Barnett Shale region of Texas has increased rapidly since 1999, and as of June 2008, over 7700 oil and gas wells had been installed and another 4700 wells were pending. Gas production in 2007 was approximately 923 Bcf from wells in 21 counties. Natural gas is a critical feedstock to many chemical production processes, and it has many environmental benefits over coal as a fuel for electricity generation, including lower emissions of sulfur, metal compounds, and carbon dioxide. Nevertheless, oil and gas production from the Barnett Shale area can impact local air quality and release greenhouse gases into the atmosphere. The objectives of this study were to develop an emissions inventory of air pollutants from oil and gas production in the Barnett Shale area, and to identify cost-effective emissions control options.

Emission sources from the oil and gas sector in the Barnett Shale area were divided into point sources, which included compressor engine exhausts and oil/condensate tanks, as well as fugitive and intermittent sources, which included production equipment fugitives, well drilling and fracing engines, well completions, gas processing, and transmission fugitives. The air pollutants considered in this inventory were smog-forming compounds (NO_x and VOC), greenhouse gases, and air toxic chemicals.

For 2009, emissions of smog-forming compounds from compressor engine exhausts and tanks were predicted to be approximately 96 tons per day (tpd) on an annual average, with peak summer emissions of 212 tpd. Emissions during the summer increase because of the effects of temperature on volatile organic compound emissions from storage tanks. Emissions of smog-forming compounds in 2009 from all oil and gas sources were estimated to be approximately 191 tpd on an annual average, with peak summer emissions of 307 tpd. The portion of those emissions originating from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 165 tpd during the summer.

For comparison, 2009 emission inventories recently used by state and federal regulators estimated smog-forming emissions from all airports in the Dallas-Fort Worth metropolitan area to be 16 tpd. In addition, these same inventories had emission estimates for on-road motor vehicles (cars, trucks, etc.) in the 9-county Dallas-Fort Worth metropolitan area of 273 tpd. The portion of on-road motor vehicle emissions from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 121 tpd, indicating that the oil and gas sector likely has greater emissions than motor vehicles in these counties.

The emission rate of air toxic compounds (like benzene and formaldehyde) from Barnett Shale activities was predicted to be approximately 6 tpd on an annual average, and 17 tpd during peak summer days. The largest contributors to air toxic emissions were the condensate tanks, followed by the engine exhausts.

In addition, predicted 2009 emissions of greenhouse gases like carbon dioxide and methane were approximately 33,000 tons per day of CO_2 equivalent. This is roughly equivalent to the expected greenhouse gas impact from two 750 MW coal-fired power plants. The largest contributors to the Barnett Shale greenhouse gas impact were CO_2 emissions from compressor engine exhausts and fugitive CH_4 emissions from all source types.

Cost effective control strategies are readily available that can substantially reduce emissions, and in some cases, reduce costs for oil and gas operators. These options include:

- use of "green completions" to capture methane and VOC compounds during well completions,
- phasing in electric motors as an alternative to internal-combustion engines to drive compressors,
- the control of VOC emissions from condensate tanks with vapor recovery units, and
- replacement of high-bleed pneumatic valves and fittings on the pipeline networks with no-bleed alternatives.

2.0 BACKGROUND

2.1 Barnett Shale Natural Gas Production

The Barnett Shale is a geological formation that the Texas Railroad Commission (RRC) estimates to extend 5000 square miles in parts of at least 21 Texas counties. The hydrocarbon productive region of the Barnett Shale has been designated as the Newark East Field, and large scale development of the natural gas resources in the field began in the late 1990's. Figure 1 shows the rapid and continuing development of natural gas from the Barnett Shale over the last 10 years.(1)

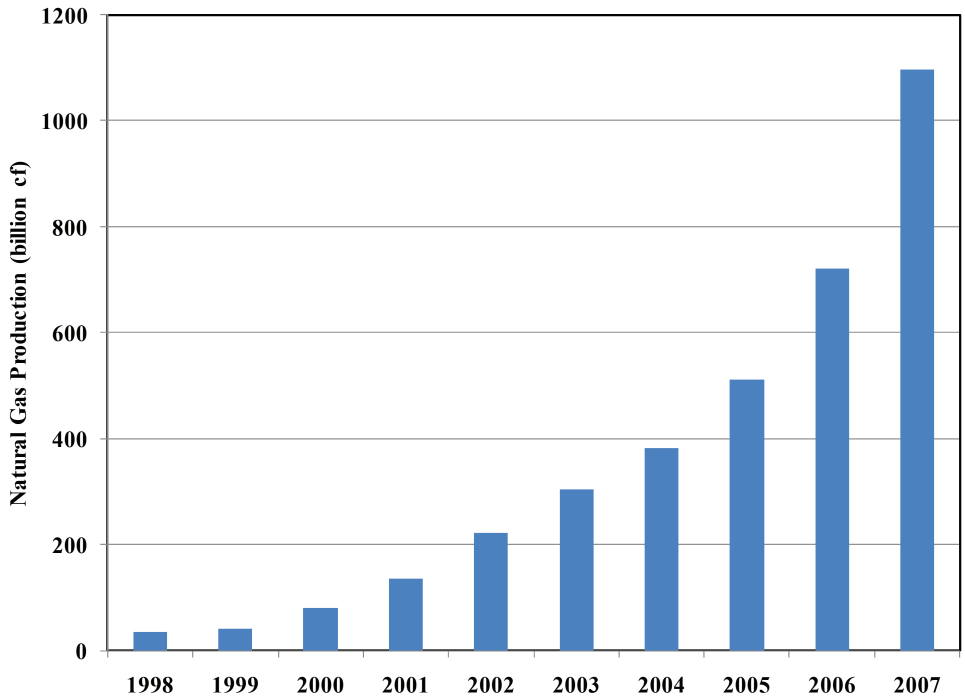


Figure 1. Barnett Shale Natural Gas Production, 1998-2007.

In addition to the recent development of the Barnett Shale, oil and gas production from other geologic formations and conventional sources in north central Texas existed before 1998 and continues to the present time. Production from the Barnett Shale is currently the dominant source of hydrocarbon production in the area from oil and gas activities in the area. Emission sources for all oil and gas activities are considered together in this report.

The issuance of new Barnett Shale area drilling permits has been following the upward trend of increasing natural gas production. The RRC issued 1112 well permits in 2004, 1629 in 2005, 2507 in 2006, 3657 in 2007, and they are on-track to issue over 4000 permits in 2008. The vast majority of the wells and permits are for natural gas production, but a small number of oil wells are also in operation or permitted in the area, and some oil wells co-produce casinghead gas. As of June 2008, over 7700 wells had been registered with the RRC, and the permit issuance rates are summarized in Table 1-1.(1) Annual oil, gas, condensate, and casinghead gas production rates for 21 counties in the Barnett Shale area are shown in Table 1-2.(1) The majority of Barnett Shale wells and well permits are located in six counties near the city of Fort Worth: Tarrant, Denton, Wise, Parker, Hood, and Johnson Counties. Figure 2 shows a RRC map of wells and well permits in the Barnett Shale.(2)

The top three gas producing counties in 2007 were Johnson, Tarrant and Wise, and the top three condensate producing counties were Wise, Denton, and Parker.

Nine (9) counties surrounding the cities of Fort Worth and Dallas have been designated by the U.S. EPA as the D-FW ozone nonattainment area (Tarrant, Denton, Parker, Johnson, Ellis, Collin, Dallas, Rockwall, and Kaufman). Four of these counties (Tarrant, Denton, Parker, and Johnson) have substantial oil or gas production. In this report, these 9 counties are referred to as the D-FW metropolitan area. The areas outside these 9-counties with significant Barnett Shale oil or gas production are generally more rural counties to the south, west, and northwest of the city of Fort Worth. The counties inside and outside the D-FW metropolitan area with oil and gas production are listed in Table 1-3.

Table 1-1. Barnett Shale Area Drilling Permits Issued, 2004-2008.(1)

year	new drilling permits
2004	1112
2005	1629
2006	2507
2007	3657
2008	4000+

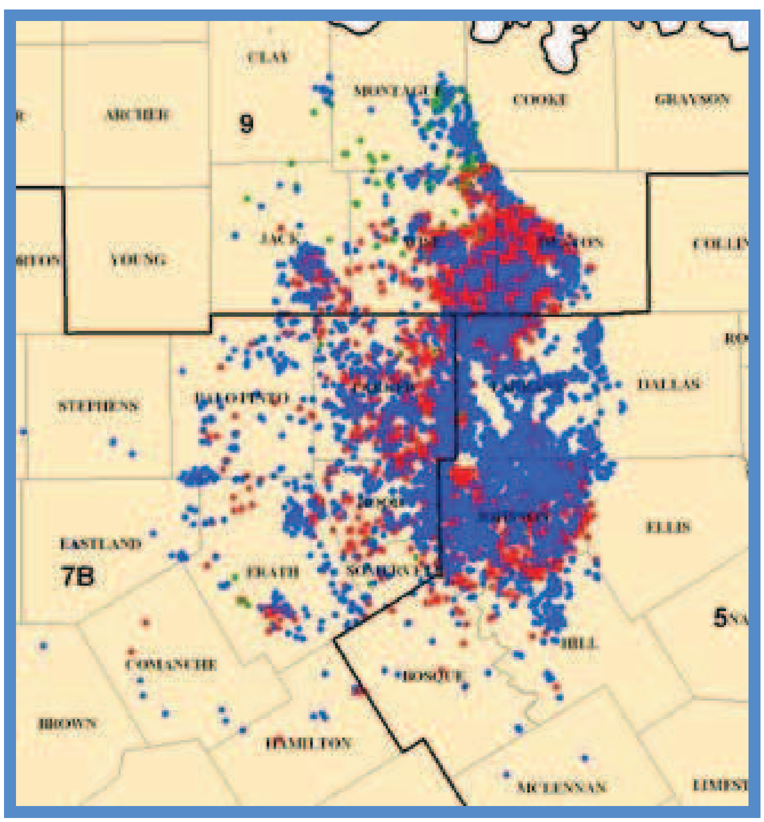
Table 1-2. Hydrocarbon Production in the Barnett Shale Area in 2007.(1)

County	Gas Production (MCF)	Condensate (BBL)	Casinghead Gas (MCF)	Oil Production (BBL)
Johnson	282,545,748	28,046	0	0
Tarrant	246,257,349	35,834	0	0
Wise	181,577,163	674,607	6,705,809	393,250
Denton	168,020,626	454,096	934,932	52,363
Parker	80,356,792	344,634	729,472	11,099
Hood	32,726,694	225,244	40,271	526
Jack	16,986,319	139,009	2,471,113	634,348
Palo Pinto	12,447,321	78,498	1,082,030	152,685
Stephens	11,149,910	56,183	3,244,894	2,276,637
Hill	7,191,823	148	0	0
Erath	4,930,753	11,437	65,425	5,073
Eastland	4,129,761	130,386	754,774	259,937
Somervell	4,018,269	6,317	0	0
Ellis	1,715,821	0	17,797	10
Comanche	560,733	1,584	52,546	7,055
Cooke	352,012	11,745	2,880,571	2,045,505
Montague	261,734	11,501	3,585,404	1,677,303
Clay	261,324	12,046	350,706	611,671
Hamilton	162,060	224	0	237
Bosque	135,116	59	0	0
Kaufman	0	0	3,002	61,963

Table 1-3. Relationship Between the D-FW Metropolitan Area and Counties Producing Oil/Gas in the Barnett Shale Area

D-FW 9-County Metropolitan Area	D-FW Metro. Counties Producing Barnett Area Oil/Gas	Rural Counties Producing Barnett Area Oil/Gas
Tarrant	Tarrant	Wise
Denton	Denton	Hood
Parker	Parker	Jack
Johnson	Johnson	Palo Pinto
Ellis	Ellis	Stephens
Collin		Hill
Dallas		Eastland
Rockwall		Somervell
Kaufman		Comanche
		Cooke
		Montague
		Clay
		Hamilton
		Bosque

Figure 2. Texas RRC Map of Well and Well Permit Locations in the Barnett Shale Area (red = gas wells, green = oil wells, blue = permits. RRC district 5, 7B, & 9 boundaries shown in black.)



2.2 Air Pollutants and Air Quality Regulatory Efforts

Oil and gas activities in the Barnett Shale area have the potential to emit a variety of air pollutants, including greenhouse gases, ozone and fine particle smog-forming compounds, and air toxic chemicals. The state of Texas has the highest greenhouse gas (GHG) emissions in the U.S., and future federal efforts to reduce national GHG emissions are likely to require emissions reductions from sources in the state. The three anthropogenic greenhouse gases of greatest concern, carbon dioxide, methane, and nitrous oxide, are emitted from oil and gas sources in the Barnett Shale area.

At present, air quality monitors in the Dallas-Fort Worth area show the area to be in compliance with the 1997 fine particulate matter ($PM_{2.5}$) air quality standard, which is 15 micrograms per cubic meter ($\mu g/m^3$) on an annual average basis. In 2006, the Clean Air Scientific Advisory Committee for EPA recommended tightening the standard to as low as 13 $\mu g/m^3$ to protect public health, but the EPA administrator kept the standard at the 1997 level. Fine particle air quality monitors in the Dallas-Fort Worth area have been above the 13 $\mu g/m^3$ level several times during the 2000-2007 time period, and tightening of the fine particle standard by future EPA administrators will focus regulatory attention at sources that emit fine particles or fine particle-forming compounds like NO_x and VOC gases.

2.3 Primary Emission Sources Involved in Barnett Shale Oil and Gas Production

There are a variety of activities that potentially create air emissions during oil and gas production in the Barnett Shale area. The primary emission sources in the Barnett Shale oil and gas sector include compressor engine exhausts, oil and condensate tank vents, production well fugitives, well drilling and hydraulic fracturing, well completions, natural gas processing, and transmission fugitives. Figure 3 shows a diagram of the major machinery and process units in the natural gas system.[3]

2.3.1 – Point Sources

i. Compressor Engine Exhausts

Internal combustion engines provide the power to run compressors that assist in the production of natural gas from wells, pressurize natural gas from wells to the pressure of lateral lines, and power compressors that move natural gas in large pipelines to and from processing plants and through the interstate pipeline network. The engines are often fired with raw or processed natural gas, and the combustion of the natural gas in these engines results in air emissions. Most of the engines driving compressors in the Barnett Shale area are between 100 and 500 hp in size, but some large engines of 1000+ hp are also used.

ii. Condensate and Oil Tanks

Fluids that are brought to the surface at Barnett Shale natural gas wells are a mixture of natural gas, other gases, water, and hydrocarbon liquids. Some gas wells produce little or no condensate, while others produce large quantities. The mixture typically is sent first to a separator unit, which reduces the pressure of the fluids and separates the natural gas and other gases from any entrained water and hydrocarbon liquids. The gases are collected off the top of the separator, while the water and hydrocarbon liquids fall to the bottom and are then stored on-site in storage tanks. The hydrocarbon liquid is known as condensate.

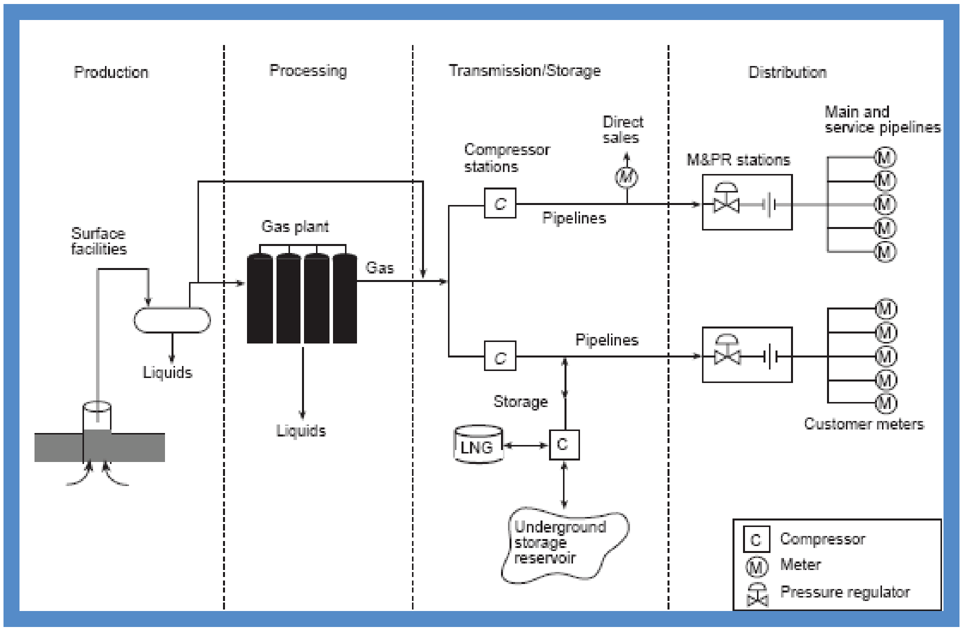


Figure 3. Major Units in The Natural Gas Industry From Wells to Customers. [(3)]

The condensate tanks at Barnett Shale wells are typically 10,000 to 20,000 gallons and hydrocarbons vapors from the condensate tanks can be emitted to the atmosphere through vents on the tanks. Condensate liquid is periodically collected by truck and transported to refineries for incorporation into liquid fuels, or to other processors. At oil wells, tanks are used to store crude oil on-site before the oil is transported to refiners. Like the condensate tanks, oil tanks can be sources of hydrocarbon vapor emissions to the atmosphere through tank vents.

2.3.2 – Fugitive and Intermittent Sources

i. Production Fugitive Emissions

Natural gas wells can contain a large number of individual components, including pumps, flanges, valves, gauges, pipe connectors, compressors, and other pieces. These components are generally intended to be tight, but leaks are not uncommon and some leaks can result in large emissions of hydrocarbons and methane to the atmosphere. The emissions from such leaks are called "fugitive" emissions. These fugitive emissions can be caused by routine wear, rust and corrosion, improper installation or maintenance, or overpressure of the gases or liquids in the piping. In addition to the unintended fugitive emissions, pneumatic valves which operate on pressurized natural gas leak small quantities of natural gas by design during normal operation. Natural gas wells, processing plants, and pipelines often contain large numbers of these kinds of pneumatic valves, and the accumulated emissions from all the valves in a system can be significant.

ii. Well Drilling, Hydraulic Fracturing, and Completions

Oil and gas drilling rigs require substantial power to from wellbores by driving drill bits to the depths of hydrocarbon deposits. In the Barnett Shale, this power is typically provided by transportable diesel engines, and operation of these engines generates exhaust from the burning of diesel fuel. After the wellbore is formed, additional power is needed to operate the pumps that move large quantities of water, sand/glass, or chemicals into the wellbore at high pressure to hydraulically fracture the shale to increase its surface area and release natural gas.

After the wellbore is formed and the shale fractured, an initial mixture of gas, hydrocarbon liquids, water, sand, or other materials comes to the surface. The standard hardware typically used at a gas well, including the piping, separator, and tanks, are not designed to handle this initial mixture of wet and abrasive fluid that comes to the surface. Standard practice has been to vent or flare the natural gas during this "well completion" process, and direct the sand, water, and other liquids into ponds or tanks. After some time, the mixture coming to the surface will be largely free of the water and sand, and then the well will be connected to the permanent gas collecting hardware at the well site. During well completions, the venting/flaring of the gas coming to the surface results in a loss of potential revenue and also in substantial methane and VOC emissions to the atmosphere.

iii. Natural Gas Processing

Natural gas produced from wells is a mixture of a large number of gases and vapors. Wellhead natural gas is often delivered to processing plants where higher molecular weight hydrocarbons, water, nitrogen, and other compounds are largely removed if they are present. Processing results in a gas stream that is enriched in methane at concentrations of usually more than 80%. Not all natural gas requires processing, and gas that is already low in higher hydrocarbons, water, and other compounds can bypass processing.

Processing plants typically include one or more glycol dehydrators, process units that dry the natural gas. In addition to water, the glycol absorbent usually collects significant quantities of hydrocarbons, which can be emitted to the atmosphere when the glycol is regenerated with heat. The glycol dehydrators, pumps, and other machinery used in natural gas processing can release methane and hydrocarbons into the atmosphere, and emissions also originate from the numerous flanges, valves, and other fittings.

iv. Natural Gas Transmission Fugitives

Natural gas is transported from wells in mostly underground gathering lines that form networks that can eventually collect gas from hundreds or thousands of well locations. Gas is transported in pipeline networks from wells to processing plants, compressor stations, storage formations, and/or the interstate pipeline network for eventual delivery to customers. Leaks from pipeline networks, from microscopic holes, corrosion, welds and other connections, as well as from compressor intake and outlet seals, compressor rod packing, blow and purge operations, pipeline pigging, and from the large number of pneumatic devices on the pipeline network can result in large emissions of methane and hydrocarbons into the atmosphere and lost revenue for producers.

2.4 Objectives

Barnett Shale area oil and gas production can emit pollutants to the atmosphere which contribute to ozone and fine particulate matter smog, are known toxic chemicals, or contribute to climate change. The objectives of this study were to examine Barnett Shale oil and gas activities and : (1) estimate emissions of volatile organic compounds, nitrogen oxides, hazardous air pollutants, methane, carbon dioxide, and nitrous oxide; (2) evaluate the current state of regulatory controls and engineering techniques used to control emissions from the oil and gas sector in the Barnett Shale; (3) identify new approaches that can be taken to reduce emissions from Barnett Shale activities; and (4) estimate the emissions reductions and cost effectiveness of implementation of new emission reduction methods.

3.0 TECHNICAL APPROACH

3.1 Pollutants

Estimates were made of 2007 and 2009 emissions of smog forming, air toxic, and greenhouse gas compounds, including nitrogen oxides (NO_x), volatile organic compounds (VOCs), air toxics a.k.a. hazardous air pollutants (HAPs), methane (CH_4), nitrous oxide (N_2O), and carbon dioxide (CO_2). Volatile organic compounds are generally carbon and hydrogen-based chemicals that exist in the gas phase or can evaporate from liquids. VOCs can react in the atmosphere to form ozone and fine particulate matter. Methane and ethane are specifically excluded from the definition of VOC because they react slower than the other VOC compounds to produce ozone and fine particles, but they are ozone-causing compounds nonetheless. The HAPs analyzed in this report are a subset of the VOC compounds, and include those compounds that are known or believed to cause human health effects at low doses. An example of a HAP compound is benzene, which is an organic compound known to contribute to the development of cancer.

Emissions of the greenhouse gases CO_2, CH_4, and N_2O were determined individually, and then combined as carbon dioxide equivalent tons (CO_2e). In the combination, CH_4 tons were scaled by 21 and N_2O tons by 310 to account for the higher greenhouse gas potentials of these gases.[4]

Emissions in 2009 were estimated by examining recent trends in Barnett Shale hydrocarbon production, and where appropriate, extrapolating production out to 2009.

State regulatory programs are different for compressor engines inside the D-FW 9-county metropolitan area compared to outside. Engine emissions were determined separately for the two groups.

3.2 Hydrocarbon Production

Production rates in 2007 for oil, gas, casinghead gas, and condensate were obtained from the Texas Railroad Commission for each county in the Barnett Shale area.[5] The large amount of production from wells producing from the Barnett Shale, as well as the smaller amounts of production from conventional formations in the area were taken together. The area was analyzed in whole, as well as by counties inside and outside the D-FW 9-county metropolitan area. Production rates in 2009 were predicted by plotting production rates from 2000-2007 and fitting a 2nd-order polynomial to the production rates via the least-squares method and extrapolating out to 2009.

3.3 Compressor Engine Exhausts - Emission Factors and Emission Estimates

Emissions from the natural-gas fired compressor engines in the Barnett Shale were calculated for two types of engines: the generally large engines that had previously reported emissions into the TCEQ's Point Source Emissions Inventory (PSEI) prior to 2007 (a.k.a. PSEI Engines), and the generally smaller engines that had not previously reported emissions (a.k.a. non-PSEI Engines). Both these engine types are located in the D-FW 9-county metropolitan area (a.k.a. D-FW Metro Area), as well as in the rural counties outside the metropolitan area (a.k.a. Outside D-FW Metro Area). The four categories of engines are summarized in Figure 4 and the methods used to estimate emissions from the engines are described in the following sections.

Figure 4. Engine Categories.

Non-PSEI Engines in D-FW Metro Area	**PSEI Engines in D-FW Metro Area**	**PSEI Engines Outside D-FW Metro Area**	**Non-PSEI Engines Outside D-FW Metro Area**

i. Non-PSEI Engines in D-FW Metropolitan Area

Large natural gas compressor engines, located primarily at compressor stations and also some at well sites, have typically reported emissions to the Texas Commission on Environmental Quality (TCEQ) in annual Point Source Emissions Inventory (PSEI) reports. However, prior to 2007, many other stationary engines in the Barnett Shale area had not reported emissions to the PSEI and their contribution to regional air quality was unknown. In late 2007, the TCEQ conducted an engine survey for counties in the D-FW metropolitan area as part as efforts to amend the state clean air plan for ozone. Engine operators reported engine counts, engine sizes, NO_x emissions, and other data to TCEQ. Data summarized by TCEQ from the survey was used for this report to estimate emissions from natural gas engines in the Barnett Shale area that had previously not reported emissions into the annual PSEI.(6) Data obtained from TCEQ included total operating engine power in the metropolitan area, grouped by rich vs. lean burn engines, and also grouped by engines smaller than 50 hp, between 50 - 500 hp, and larger than 500 hp.

Regulations adopted by TCEQ and scheduled to take effect in early 2009 will limit NO_x emissions in the D-FW metropolitan area for engines larger than 50 horsepower.(7) Rich burn engines will be restricted to 0.5 g/hp-hr, lean burn engines installed or moved before June 2007 will be restricted to 0.7 g/hp-hr, and lean burn engines installed or moved after June 2007 will be limited to 0.5 g/hp-hr. For this report, emissions in 2009 from the engines in the metropolitan area subject to the new rules were estimated assuming 97% compliance with the upcoming rules and a 3% noncompliance factor for engines continuing to emit at pre-2009 levels.

Emissions for 2007 were estimated using NO_x emission factors provided by operators to TCEQ in the 2007 survey.(6) Emissions of VOCs were determined using TCEQ-determined emission factors, and emissions of HAPs, CH_4, and CO_2 were determined using emission factors from EPA's AP-42 document.(8,9) In AP-42, EPA provides emission factors for HAP compounds that are created by incomplete fuel combustion. For this report only those factors which were judged by EPA to be of high quality, "A" or "B" ratings, were used to estimate emissions. Emission factors for the greenhouse gas N_2O were from an emissions inventory report issued by the American Petroleum Institute.(10)

Beginning in 2009, many engines subject to the new NO_x limits are expected to reduce their emissions with the installation of non-selective catalytic reduction units (NSCR), a.k.a. three-way catalysts. NSCR units are essentially modified versions of the "catalytic converters" that are standard equipment on every gasoline-engine passenger vehicle in the U.S.

A likely co-benefit of NSCR installation will be the simultaneous reduction of VOC, HAP, and CH_4 emissions. Emissions from engines expected to install NSCR units were determined using a 75% emissions reduction factor for VOC, HAPs, and CH_4. Conversely, NSCR units are known to increase N_2O emissions, and N_2O emissions were estimated using a 3.4x factor increase over uncontrolled emission factors.(10) Table 2 summarizes the emission factors used to calculate emissions from the compressor engines identified in the 2007 survey.

Table 2. Emission Factors for Engines Identified in the D-FW 2007 Engine Survey

Table 2-1. Emission Factors for 2007 Emissions

engine type	engine size	NO_x (g/hp-hr)[a]	VOC (g/hp-hr)[b]	HAPs (g/hp-hr)[c]	CH_4 (g/hp-hr)[d]	CO_2 (g-hp-hr)[e]	N_2O (g-hp-hr)[f]
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	13.6	0.43	0.088	0.89	424	0.0077
rich	>500	0.9	0.43	0.088	0.89	424	0.0077
lean	<500	6.2	1.6	0.27	4.8	424	0.012
lean	>500	0.9	1.6	0.27	4.8	424	0.012

Table 2-2. Emission Factors for 2009 Emissions

engine type	engine size	NO_x (g/hp-hr)[i]	VOC (g/hp-hr)[j]	HAPs (g/hp-hr)[k]	CH_4 (g/hp-hr)[l]	CO_2 (g-hp-hr)[m]	N_2O (g-hp-hr)[n]
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	0.5	0.11	0.022	0.22	424	0.026
rich	>500	0.5	0.11	0.022	0.22	424	0.026
lean[g]	<500	0.62	1.6	0.27	4.8	424	0.012
lean[h]	<500	0.5	1.6	0.27	4.8	424	0.012
lean[g]	>500	0.7	1.45	0.27	4.8	424	0.012
lean[h]	>500	0.5	1.45	0.27	4.8	424	0.012

notes:
a: email from TCEQ to SMU, August 1, 2008, summary of results from 2007 engine survey (reference 6).
b: email from TCEQ to SMU, August 6, 2008 (reference 8).
c: EPA, AP-42, quality A and B emission factors; rich engine HAPs = benzene, formaldehyde, toluene; lean engine HAPs = acetaldehyde, acrolein, xylene, benzene, formaldehyde, methanol, toluene, xylene (reference 9).
d: EPA, AP-42 (reference 9).
e: EPA, AP-42 (reference 9).
f: API Compendium Report (reference 10).
g: engines installed or moved before June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).
h: engines installed or moved after June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).
i: rich (<50) factor from email from TCEQ to SMU, August 1, 2008 (reference 6); rich (50-500), rich (>500), lean (<500, post-2007), lean (>500, pre-2007), and lean (>500, post-2007) from TCEQ regulatory limits (reference 7); lean (<500, pre-2007) estimated with 90% control.
j: rich (<50) from email from TCEQ to SMU (reference 8); rich (50-500) and rich (>500) estimated with 75% NSCR control VOC co-benefit; lean EFs from email from TCEQ to SMU (reference 8). Large lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.
k: EPA, AP-42 (reference 9); rich (50-500) and rich (>500) estimated with 75% control co-benefit.
l: EPA, AP-42 (reference 9); rich (50-500) and rich (>500) estimated with 75% control co-benefit.
m: EPA, AP-42 (reference 9).
n: API Compendium Report (reference 10); rich (50-500) and rich (>500) estimated with 3.4x N_2O emissions increase over uncontrolled rate.

Annual emissions from the engines identified in the 2007 survey were estimated using the pollutant-specific emission factors from Table 1 together with Equation 1,

$$M_{E,i} = 1.10E\text{-}06 * E_i * P_{cap} * F_{hl} \quad (1)$$

where $M_{E,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in grams/hp-hr, P_{cap} is installed engine capacity in hp, and F_{hl} is a factor to adjust for annual hours of operation and typical load conditions.

Installed engine capacity in 2007 was determined for six type/size categories using TCEQ estimates from the 2007 engine survey - two engine types (rich vs. lean) and three engine size ranges (<50, 50-500, >500 hp) were included.[6] TCEQ estimates of the average engine sizes and the numbers of engines in each size category were used to calculate the installed engine capacity for each category, as shown in Table 3. The F_{hl} factor was used to account for typical hours of annual operation and average engine loads. A F_{hl} value of 0.5 was used for this study, based on 8000 hours per year of average engine operation (8000/8760 = 0.91) and operating engine loads of 55% of rated capacity, giving an overall hours-load factor of 0.91x 0.55 = 0.5.[11]

Table 3. Installed Engine Capacity in 2007 D-FW Engine Survey by Engine Type and Size

engine type	engine size (hp)	number of engines[q]	typical size[q] (hp)	installed capacity[r] (hp)
rich	<50	12	50	585
rich	50-500	724	140	101,000
rich	>500	200	1400	280,000
lean[o]	<500	14	185	2540
lean[p]	<500	13	185	2400
lean[o]	>500	103	1425	147,000
lean[p]	>500	103	1425	147,000

notes:
o: engines installed or moved before June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).
p: engines installed or moved after June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).
q: rich (<50) installed capacity based on HARC October 2006 H68 report which found that small rich burn engines comprise no more than 1% of engines in East Texas; rich (50-500) and rich (>500) installed capacity from email TCEQ to SMU in August 1, 2008 (reference 6); lean burn installed capacity from email TCEQ to SMU in August 1, 2008 (reference 6) along with RRC data suggesting that 50% of engines in 2009 will be subject to the post-June 2007 NOx rule.
r: installed capacity = number of engines x typical size

ii. PSEI Engines in D-FW Metropolitan Area

In addition to the engines identified in the 2007 TCEQ survey of the D-FW 9-county metropolitan area, many other stationary engines are also in use in the area. These include engines that had already been reporting annual emissions to TCEQ in the PSEI, which are principally large engines at compressor stations.[12]

Emissions of NO_x from large engines in the D-FW metropolitan area that were reporting to the TCEQ PSEI were obtained from the 2006 Annual PSEI, the most recent calendar year available.(12) Emissions for 2007 and 2009 were estimated by extrapolating 2006 emissions upward to account for increases in gas production and compression needs from 2006-2009. For NO_x emissions in 2006 and 2007, an average emission factor of 0.9 g/hp-hr was obtained from TCEQ.(8) Emissions in 2009 were adjusted by accounting for the 0.5 g/hp-hr TCEQ regulatory limit scheduled to take effect in early 2009 for the D-FW metropolitan area.(7)

Unlike NO_x emission, emissions of VOC were not taken directly from the PSEI. Estimates of future VOC emissions required accounting for the effects that the new TCEQ engine NO_x limits will have on future VOC emissions. A compressor engine capacity production factor of 205 hp/(MMcf/day) was obtained from TCEQ that gives a ratio of installed horsepower capacity to the natural gas production. The 205 hp/(MMcf/day) factor was based on previous TCEQ studies of gas production and installed large engine capacity. The factor was used with 2006 gas production values to estimate installed PSEI engine capacities for each county in the Barnett Shale area.(8) Engine capacities were divided between rich burn engines smaller and larger than 500 hp, and lean burn engines. To estimate 2009 emissions, rich burn engines smaller than 500 hp are expected to have NSCR units by 2009 and get 75% VOC, HAP, and CH_4 control. Table 4 summarizes the VOC, HAP, and greenhouse gas emission factors used for the PSEI engines in the D-FW metropolitan area. Table 5 summarizes the estimates of installed engine capacity for each engine category.

Table 4. VOC, HAP, GHG Emission Factors for PSEI Engines in D-FW Metropolitan Area

Table 4-1. Emission Factors for 2007 Emissions

engine type	engine size	VOC EFs (g/hp-hr)[s]	HAPs EF (g/hp-hr)[t]	CH_4 EF (g/hp-hr)[u]	CO_2 EF (g/hp-hr)[v]	N_2O (g/hp-hr)[w]
rich	<500	0.43	0.088	0.89	424	0.0077
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.6	0.27	4.8	424	0.012

Table 4-2. Emission Factors for 2009 Emissions

engine type	engine size	VOC EFs (g/hp-hr)[s]	HAPs EF (g/hp-hr)[t]	CH_4 EF (g/hp-hr)[u]	CO_2 EF (g/hp-hr)[v]	N_2O (g/hp-hr)[w]
rich	<500	0.11	0.022	0.22	424	0.026
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.47	0.27	4.8	424	0.012

notes:

s: email from TCEQ to SMU, August 6, 2008; 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 8). Large lean engine VOC emission factor adjusted from 1.6 to 1.47 to account for the effects of NSPS JJJJ rules on VOC emissions.

t: EPA, AP-42 (reference 9); 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 9).

u: EPA, AP-42 (reference 9) ; 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 9).

v: EPA, AP-42 (reference 9).

w: API Compendium Report; 2007 rich (>500), and 2009 rich (>500) and 2009 rich (<500) engines estimated with 3.4x N_2O emissions increase over uncontrolled rate (reference 10).

Table 5. Installed Engine Capacity in 2007 for PSEI Engines Inside D-FW Metropolitan Area

engine type	engine size (hp)	installed capacity (%)[x]	installed capacity (hp)[y]
rich	<500	0.14	59,500
rich	>500	0.52	221,000
lean	all	0.34	144,000

notes:
x: distribution of engine types and sizes estimated from October 2006 HARC study (reference 13).
y: estimated as the installed capacity (%) x the total installed capacity based on the TCEQ compressor engine capacity production factor of 205 hp/(MMcf/day) (references 5,8).

iii. PSEI Engines Outside D-FW Metropolitan Area

Emissions of NO_x from large engines outside the D-FW metropolitan area reporting to the TCEQ were obtained from the 2006 PSEI.[12] Emissions for 2007 and 2009 were estimated by extrapolating 2006 emissions upward to account for increases in gas production from 2006-2009. Unlike engines inside the metropolitan area, the engines outside the metropolitan area are not subject to the new D-FW engine rules scheduled to take effect in 2009.

In addition to the D-FW engine rules, in 2007 the TCEQ passed the East Texas Combustion Rule that limited NO_x emissions from rich-burn natural gas engines larger than 240 hp in certain east Texas counties. Lean burn engines and engines smaller than 240 hp were exempted. The initial proposed rule would have applied to some counties in the Barnett Shale production area, including Cooke, Wise, Hood, Somervell, Bosque, and Hill, but in the final version of the rule these counties were removed from applicability, with the exception of Hill, which is still covered by the rule. Since gas production from Hill County is less than 3.5% of all the Barnett Shale area gas produced outside the D-FW metropolitan area, the East Texas Combustion Rule has limited impact to emissions from Barnett Shale area activity.

Emissions of VOC, HAPs, and greenhouse gases for large engines outside the D-FW metropolitan area were not obtained from the 2006 PSEI. A process similar to the one used to estimate emissions from large engines inside the metropolitan area was used, whereby the TCEQ compressor engine capacity production factor, 205 hp/(MMcf/day), was used along with actual 2007 production rates to estimate total installed engine capacity as well as installed capacity in each county for different engine categories. Pollutant-specific emission factors were applied to the capacity estimates for each category to estimate emissions. Table 6 summarizes the emission factors used to estimate emissions from engines in the PSEI outside the D-FW metropolitan area. The engine capacities used to estimate emissions are shown in Table 7.

Table 6. VOC, HAP, GHG Emission Factors for PSEI Engines Outside D-FW Metropolitan Area

engine type	engine size	VOC (g/hp-hr)[z]	HAPs (g/hp-hr)[aa]	CH_4 (g/hp-hr)[aa]	CO_2 (g-hp-hr)[bb]	N_2O (g-hp-hr)[cc]
rich	<500	0.43	0.088	0.89	424	0.0077
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.45	0.27	4.8	424	0.012

notes:
z: email from TCEQ to SMU, August 6, 2008; 75% control applied to rich (>500) engines (reference 8). Large lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.
aa: EPA, AP-42; 75% control applied to rich (>500) engines (reference 9).

bb. EPA, AP-42 (reference 9).
cc. API Compendium Report; rich (>500) engines estimated with 3.4x N_2O emissions increase over uncontrolled rate (reference 10).

Table 7. Installed Engine Capacity in 2007 for PSEI Engines Outside D-FW Metropolitan Area

engine type	engine size (hp)	installed capacity (%)[dd]	installed capacity (hp)[ee]
rich	<500	0.14	17,000
rich	>500	0.52	62,000
lean	all	0.34	41,000

notes:
dd: distribution of engine types and sizes estimated from October 2006 HARC study (reference 13).
ee: estimated as the installed capacity (%) x the total installed capacity based on the TCEQ compressor engine capacity production factor of 205 hp/(MMcf/day) (references 5,8).

iv. Non-PSEI Engines Outside the D-FW Metropolitan Area

The Point Source Emissions Inventory (PSEI) only contains emissions from a fraction of the stationary engines in the Barnett Shale area, principally the larger compressor engines with emissions above the PSEI reporting thresholds. The 2007 TCEQ engine survey of engines inside the D-FW metropolitan area demonstrated that the PSEI does not include a substantial fraction of total engine emissions. Most of the missing engines in the metropolitan area were units with emissions individually below the TCEQ reporting thresholds, but the combined emissions from large numbers of smaller engines can be substantial. The results of the 2007 survey indicated that there were approximately 680,000 hp of installed engine capacity in the D-FW metropolitan area not previously reporting to the PSEI.(6)

Natural gas and casinghead gas production from metropolitan counties in 2007 was approximately 1,000 Bcf . A "non-PSEI" compressor engine capacity production factor of 226 hp/(MMcf/day) was determined for the Barnett Shale area. This capacity factor accounts for all the small previously hidden engines that the 2007 survey showed come into use in oil and gas production activities in the area. This production factor was used along with 2007 gas production rates for the counties outside the D-FW metropolitan area to estimate non-PSEI engine emissions from these counties. The new production factor accounts for the fact that counties outside the metro area likely contain previously unreported engine capacity in the same proportion to the unreported engine capacity that was identified during the 2007 engine survey inside the metro area. Without a detailed engine survey in the rural counties of the same scope as the 2007 survey performed within the D-FW metropolitan counties, use of the non-PSEI production factor provides a way to estimate emissions from engines not yet in state or federal inventories. The capacity of non-PSEI reporting engines in the rural counties of the Barnett Shale was determined by this method to be 132,000 hp. Emission factors used to estimate emissions from these engines, and the breakdown of total installed engine capacity into engine type and size categories, are shown in Tables 8 and 9.

Table 8. Emission Factors for Non-PSEI Engines Outside D-FW Metropolitan Area

engine type	engine size	NO_x (g/hp-hr)[ff]	VOC (g/hp-hr)[gg]	HAPs (g/hp-hr)[hh]	CH_4 (g/hp-hr)[hh]	CO_2 (g-hp-hr)[ii]	N_2O (g-hp-hr)[jj]
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	10.3	0.43	0.088	0.89	424	0.0077
rich	>500	0.89	0.11	0.022	0.22	424	0.026
lean	<500	5.2	1.45	0.27	4.8	424	0.012
lean	>500	0.9	1.6	0.27	4.8	424	0.012

notes:
ff: email from TCEQ to SMU, August 1, 2008 (reference 6). Rich burn engines 50-500 hp NOx emission factor adjusted from 13.6 to 10.3 to account for the effects of NSPS JJJJ rules on NOx emissions and the effect of the TCEQ East Texas Combustion Rule on Hill County production. Rich burn engines >500 adjusted from 0.9 to 0.89 to account for the effect of the TCEQ East Texas Combustion Rule on Hill County production. Lean burn <500 hp engine post-2007 emission factor adjusted from 6.2 to 5.15 to account for the effects of NSPS JJJJ rules on NOx emissions.
gg: email from TCEQ to SMU, August 6, 2008; rich (>500) based on 75% control (reference 8). Small lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.
hh: EPA, AP-42; rich (>500) based on 75% control (reference 9).
ii: EPA, AP-42 (reference 9).
jj: API Compendium Report; rich (>500) estimated with 3.4x N_2O emissions increase over uncontrolled rate (reference 10).

Table 9. Installed Engine Capacity for Non-PSEI Engines Outside Metropolitan Area by Engine Type/Size

engine type	engine size (hp)	installed capacity (%)	installed capacity (hp)
rich	<50	0.01	110
rich	50-500	15	20,000
rich	>500	41	55,000
lean	<500	0.73	970
lean	>500	43	57,000

3.2 Condensate and Oil Tanks - Emission Factors and Emission Estimates

Condensate and oil tanks can be significant emitters of VOC, methane, and HAPs. A report was published in 2006 by URS Corporation which presented the results of a large investigation of emissions from condensate and oil tanks in Texas.[(14)] Tanks were sampled from 33 locations across East Texas, including locations in the Barnett Shale area. Condensate tanks in the Barnett Shale were sampled in Denton and Parker Counties, and oil tanks were sampled in Montague County. The results from the URS investigation were used in this study to calculate Barnett Shale-specific emission factors for VOC, CH_4, HAPs, and CO_2, instead of using a more general Texas-wide emission factor. The URS study was conducted during daylight hours in July 2006, when temperatures in North Texas are significantly above the annual average. Therefore, the results of the URS investigation were used to calculate "Peak Summer" emissions. The HAPs identified in the URS study included n-hexane, benzene, trimethylpentane, toluene, ethylbenzene, and xylene. The emission factors used to calculate peak summer emissions from Barnett

Shale condensate and oil tanks are shown in Table 10-1. Figure 5 shows a condensate tank battery from the 2006 URS study report.

Figure 5. Example Storage Tank Battery (left), Separators (right), and Piping.[14]

Computer modeling data were provided during personal communications with a Barnett Shale gas producer who estimated VOC, CH_4, HAPs, and CO_2 emissions from a number of their condensate tanks.[15] The tanks were modeled with ambient temperatures of 60 F, which the producer used to represent annual hourly mean temperatures in the D-FW area. These modeling results were used in this report to predict annual average condensate tank emission factors for the Barnett Shale area. The annual average emission factors are shown in Table 10-2.

Table 10. Condensate and Oil Tank Emission Factors for the Barnett Shale.

Table 10-1. Peak Summer Emission Factors.[14]

	VOC (lbs/bbl)	HAPs (lbs/bbl)	CH_4 (lbs/bbl)	CO_2 (lbs/bbl)
condensate	48	3.7	5.6	0.87
oil	6.1	0.25	0.84	2.7

Table 10-2. Annual Average Emission Factors.[15]

	VOC (lbs/bbl)	HAPs (lbs/bbl)	CH_4 (lbs/bbl)	CO_2 (lbs/bbl)
condensate	10	0.20	1.7	0.23
oil	1.3	0.013	0.26	0.70

Emissions for 2007 were calculated for each county in the Barnett Shale area, using condensate and oil production rates from the RRC.[5] Emissions for 2009 were estimated with the extrapolated 2000-2007 production rates for the year 2009. Emissions were calculated with Equation 2,

$$M_{T,i} = E_i * P_c * C / 2000 \qquad (2)$$

where $M_{T,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/bbl, P_c was the production rate of condensate or oil, and C was a factor to account for the reduction in emissions due to vapor-emissions controls on some tanks. For this report, the use of vapor-emissions controls on some tanks was estimated to provide a 25% reduction in overall area-wide emissions.

3.3 Production Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from production wells vary from well to well depending on many factors, including the tightness of casing heads and fittings, the age and condition of well components, and the numbers of flanges, valves, pneumatic devices, or other components per well. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.[15] Fugitive emissions of natural gas from the entire natural gas network were estimated to be 1.4% of gross production. Production fugitives, excluding emissions from condensate tanks (which are covered in another section of this report), were estimated by the GRI/EPA study to be approximately 20% of total fugitives, or 0.28% of gross production.

Production fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.28% of gross natural gas and casinghead gas production of 1098 Bcf/yr. Volume emissions were converted to mass emissions with a density of 0.0483 lb/scf. Multiple Barnett Shale gas producers provided gas composition, heat content data, and area-wide maps of gas composition. The area-wide maps of gas composition were used to estimate gas composition for each producing county. These county-level data were weighted by the fraction of total area production that originated from each county to calculate area-wide emission factors. Table 11 presents the production fugitives emission factors.

Table 11. Production Fugitives Emission Factors for the Barnett Shale.

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH_4 (lbs/MMcf)	CO_2 (lbs/MMcf)
11	0.26	99	1.9

Emissions were calculated with Equation 3,

$$M_{F,i} = E_i * P_g / 2000 \tag{3}$$

where $M_{F,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/MMcf, and P_g was the production rate of natural and casinghead gas. The area-wide unprocessed natural gas composition based on data from gas producers was 74% CH_4, 8.2% VOC, 1.4% CO_2, and 0.20% HAPs, on a mass % basis. HAPs in unprocessed natural gas can include low levels of n-hexane, benzene, or other compounds.

3.4 Well Drilling, Hydraulic Fracturing Pump Engines, and Well Completions - Emission Factors and Emission Estimates

Emissions from the diesel engines used to operate well drilling rigs and from the diesel engines that power the hydraulic fracturing pumps were estimated based on discussions with gas producers and other published data. Well drilling engine emissions were based on 25 days of engine operation for a typical well, with 1000 hp of engine capacity, a load factor of 50%, and operation for 12 hours per day. Hydraulic fracturing engine emissions were based on 4.5 days of operation for a typical well, with 1000 hp of capacity, a load factor of 50%, and operation for 12 hours per day. Some well sites in the D-FW are being drilled with electric-powered rigs, with electricity provided off the electrical grid. Engines emission estimates in this report were reduced by 25% to account for the number of wells being drilled without diesel-engine power.

In addition to emissions from drilling and fracing engines, previous studies have examined emissions of natural gas during well completions. These studies include one by the Williams gas company, which estimated that a typical well completion could vent 24,000 Mcf of natural gas.[18] A report by the EPA Natural Gas Star program estimated that 3000 Mcf could be produced from typical well completions.[19] A report by ENVIRON published in 2006 describes emission factors used in Wyoming and Colorado to estimate emissions from well completions, which were equivalent to 1000 to 5000 Mcf natural gas/well.[20] Another report published in the June 2005 issue of the Journal of Petroleum Technology estimated that well completion operations could produce 7,000 Mcf. [21] Unless companies bring special equipment to the well site to capture the natural gas and liquids that are produced during well completions, these gases will be vented to the atmosphere or flared.

Discussions with Barnett Shale gas producers that are currently employing “green completion” methods to capture natural gas and reduce emissions during well completions suggests that typical well completions in the Barnett Shale area can release approximately 5000 Mcf of natural gas/well. This value, which is very close to the median value obtained from previous studies (References 18-21), was used to estimate well completion emissions in this report.

The number of completed gas wells reporting to the RRC was plotted for the Feb. 2004 – Feb. 2008 time period.[22] A least-squares regression line was fit to the data, and the slope of the line provides the approximate number of new completions every year. A value of 1042 completions/year was relatively steady throughout the 2004-2008 time period (linear $R^2 = 0.9915$). Emissions in 2007 and 2009 from well completions were estimated using 1000 new well completions/year for each year. Emission estimates were prepared for the entire Barnett Shale area, as well as inside and outside the D-FW metropolitan area. The data from 2004-2008 show that 71 percent of new wells are being installed in the D-FW metropolitan area, 29 percent of new wells are outside the metropolitan area, and the rate of new completions has been steady since 2004. Emissions of VOC, HAPs, CH_4, and CO_2 were estimated using the same natural gas composition used for production fugitive emissions.

Some gas producers are using green completion techniques to reduce emissions, while others destroy natural gas produced during well completions by flaring. To account for the use of green completions and control by flaring, natural gas emission estimates during well completions were reduced by 25% in this report.

3.5 Processing Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from natural gas processing will vary from processing plant to processing plant, depending on the age of the plants, whether they are subject to federal rules such as the NSPS Subpart KKK requirements, the chemical composition of the gas being processed, the processing capacity of the plants, and other factors. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.(15) Fugitive emissions of natural gas from the entire natural gas industry were estimated to be 1.4% of gross production. Processing fugitives, excluding compressor engine exhaust emissions that were previously addressed in this report, were estimated to be approximately 9.7% of total fugitives, or 0.14% of gross production.

Processing fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.14% of the portion of gas production that is processed, estimated as 519 Bcf/yr. Emission factors for VOC, HAPs, CH_4, and CO_2 were estimated with an area-wide natural gas composition, excluding the gas from areas of the Barnett Shale that does not require any processing. Volume emissions were converted to mass emissions with a natural gas density of 0.0514 lb/scf. Table 12 presents the processing fugitives emission factors.

Table 12. Processing Fugitives Emission Factors for the Barnett Shale.

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH_4 (lbs/MMcf)	CO_2 (lbs/MMcf)
14	0.3	45	1.0

Processing fugitive emissions were calculated with Equation 4,

$$M_{P,i} = E_i * P_g / 2000 \qquad (4)$$

where $M_{P,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/MMcf, and P_g was the production rate of natural and casinghead gas. The composition of the natural gas produced in the Barnett Shale that is processed was estimated to be 65% CH_4, 1.5% CO_2, 20% VOC, and 0.48% HAPs, on a mass % basis. Not all natural gas from the Barnett Shale area requires processing.

3.6 Transmission Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from the transmission of natural gas will vary depending on the pressure of pipelines, the integrity of the piping, fittings, and valves, the chemical composition of the gas being transported, the tightness of compressor seals and rod packing, the frequency of blow down events, and other factors. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.[(15)] Fugitive emissions of natural gas from the entire natural gas industry were estimated to be 1.4% of gross production. Transmission fugitives, excluding compressor engine exhaust emissions that were previously addressed in this report, were estimated to be approximately 35% of total fugitive emissions, or 0.49% of gross production. Transmission includes the movement of natural gas from the wells to processing plants, and the processing plants to compressor stations. It does not include flow past the primary metering and pressure regulating (M&PR) stations and final distribution lines to customers. Final distribution of gas produced in the Barnett Shale can happen anywhere in the North American natural gas distribution system, and fugitive emissions from these lines are beyond the scope of this report.

Transmission fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.49% of gross natural gas and casinghead gas production of 1098 Bcf/yr. Emission factors for VOC, HAPs, CH_4, and CO_2 were developed considering that a significant portion of the gas moving through the network does not require processing, while the portion of the gas with higher molecular weight compounds will go through processing. In addition, all gas will have a dry (high methane) composition after processing as it moves to compressor stations and then on to customers. Overall area-wide transmission fugitive emissions were calculated with a gas composition of 76% CH_4, 5.1% VOC, 1.4% CO_2, and 0.12% HAPs, by mass %. Table 13 presents the transmission fugitives emission factors.

Table 13. Transmission Fugitives Emission Factors for the Barnett Shale.

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH_4 (lbs/MMcf)	CO_2 (lbs/MMcf)
12	0.28	175	3.3

Transmission fugitive emissions were calculated with Equation 5,

$$M_{tr,i} = E_i * P_g / 2000 \qquad (5)$$

where $M_{tr,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/MMcf, and P_g was the production rate of natural and casinghead gas.

4.0 RESULTS

4.1 Point Sources

i. Compressor Engine Exhausts

Emissions from compressor engines in the Barnett Shale area are summarized in Tables 14 and 15. Results indicate that engines are significant sources of ozone and particulate matter precursors (NO_x and VOC), with 2007 emissions of 66 tpd. Emissions of NO_x are expected to fall 50% from 32 to 16 tpd for engines in the Dallas-Fort Worth metropolitan area because of regulations scheduled to take effect in 2009 and the installation of NSCR units on many engines. Large reductions are unlikely because of the growth in natural gas production. For engines outside the D-FW metropolitan area counties, NO_x emissions will rise from 19 tpd to 30 tpd because of the projected growth in natural gas production and the fact that engines in these counties are not subject to the same regulations as those inside the metropolitan area.

Emissions of volatile organic compounds are expected to increase from 15 to 21 tpd from 2007 to 2009, because of increasing natural gas production. The 2009 engine regulations for the metropolitan area counties do have the effect of reducing VOC emissions from some engines, but growth in production compensates for the reductions and VOC emissions from engines as a whole increase.

HAP emissions, which include toxic compounds such as formaldehyde and benzene, are expected to increase from 2.7 to 3.6 tpd from 2007 to 2009.

Greenhouse gas emissions from compressor engines are shown in Table 15. Emissions in 2007 as carbon dioxide equivalent tons were approximately 8900 tpd, and emissions are estimated to increase to nearly 14,000 tpd by 2009. Carbon dioxide contributed the most to the greenhouse gas emissions, accounting for approximately 90% of the CO_2 equivalent tons. The methane contribution to greenhouse gases was smaller for the engine exhausts than for the other sources reviewed in this report.

Table 14. Emissions from Compressor Engine Exhausts.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
D-FW Metro Engines	32	13	2.2	35	7261	16	16	2.9	49	11294
Outside Metro Engines	19	2.5	0.45	7.4	1649	30	3.8	0.70	12	2583
Engines Total	**51**	**15**	**2.7**	**43**	**8910**	**46**	**19**	**3.6**	**61**	**13877**

Table 15. Greenhouse Gas Emissions Details.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	CO2	CH4	N2O	CO2e	CO2	CH4	N2O	CO2e
D-FW Metro Engines	6455	35	0.20	7261	10112	49	0.28	11294
Outside Metro Engines	1475	7.4	0.062	1649	2310	12	0.10	2583
Engines Total	**7930**	**43**	**0.26**	**8910**	**12422**	**61**	**0.38**	**13877**

ii. Oil and Condensate Tanks

Emissions from condensate and oil tanks are shown in Tables 16-1 and 16-2. Annual average emissions are shown in Table 16-1, and peak summer emissions are shown in Table 16-2.

On an annual average, emissions of VOCs from the tanks were 19 tpd in 2007, and emissions will increase to 30 tpd in 2009. Because of the effects of temperature on hydrocarbon liquid vapor pressures, peak summer emissions of VOC were 93 tpd in 2007, and summer emissions will increase to 146 tpd in 2009.

Substantial HAP emissions during the summer were determined for the tanks, with 2007 emissions of 7.2 tpd and 2009 emissions of 11 tpd. Greenhouse gas emissions from the tanks are almost entirely from CH_4, with a small contribution from CO_2. Annual average greenhouse gas emissions were 95 tpd in 2007, and will increase to 149 tpd in 2009.

Table 16. Emissions from Condensate and Oil Tanks.

Table 16-1. Annual Average Tank Emissions

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Tanks	8.9	0.18	2.1	44	14	0.28	3.2	69
Outside Metro Tanks	10	0.21	2.4	51	16	0.32	3.8	80
Tanks Total	**19**	**0.39**	**4.5**	**95**	**30**	**0.60**	**7.0**	**149**

Table 16-2. Peak Summer Tank Emissions

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Tanks	43	3.3	6.7	142	67	5.2	10	222
Outside Metro Tanks	50	3.8	7.8	166	79	6.0	12	261
Tanks Total	**93**	**7.2**	**15**	**308**	**146**	**11**	**23**	**483**

4.2 Fugitive and Intermittent Sources

i. Production Fugitives

Emissions from fugitive sources at Barnett Shale production sites are shown in Table 17. Production fugitives are significant sources of VOC emissions, with VOC emissions expected to grow from 2007 to 2009 from 17 to 26 tpd. Production fugitives are also very large sources of methane emissions, leading to large CO_2 equivalent greenhouse gas emissions. Greenhouse gas emissions were 3100 tpd in 2007 and will be 4900 tpd in 2009.

Table 17. Emissions from Production Fugitives.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Production Fugitives	11	0.27	102	2147	18	0.43	160	3363
Outside Metro Production Fugitives	5.2	0.12	46	971	8.1	0.19	72	1521
Production Fugitives Total	**17**	**0.40**	**148**	**3118**	**26**	**0.62**	**232**	**4884**

ii. Well Drilling, Hydraulic Fracturing, and Well Completions

Emissions from well drilling engines, hydraulic fracturing pump engines, and well completions are shown in Table 18. These activities are significant sources of the ozone and fine particulate precursors, as well as very large sources of greenhouse gases, mostly from methane venting during well completions. Greenhouse gas emissions are estimated to be greater than 4000 CO_2 equivalent tons per year. Based on 2000-2007 drilling trends, approximately 71% of the well drilling, fracing, and completion emissions will be coming from counties in the D-FW metropolitan area, with the remaining 29% coming from counties outside the metropolitan area.

Table 18. Emissions from Well Drilling, Hydraulic Fracturing, and Well Completions.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
D-FW Metro Well Drilling and Well Completion	3.9	15	0.35	130	2883	3.9	15	0.35	130	2883
Outside Metro Well Drilling and Well Completions	1.6	6.1	0.14	53	1178	1.6	6.1	0.14	53	1178
Well Drilling and Completions Emissions Total	**5.5**	**21**	**0.49**	**183**	**4061**	**5.5**	**21**	**0.49**	**183**	**4061**

iii. Natural Gas Processing

Processing of Barnett Shale natural gas results in significant emissions of VOC and greenhouse gases, which are summarized in Table 19. Emissions of VOC were 10 tpd in 2007 and are expected to increase to 15 tpd by 2009. Greenhouse gas emissions, largely resulting from fugitive releases of methane, were approximately 670 tpd in 2007 and will be approximately 1100 tpd in 2009.

Table 19. Emissions from Natural Gas Processing.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Processing Fugitives	6.7	0.16	22	464	10	0.26	35	727
Outside Metro Processing Fugitives	3.0	0.07	10	210	4.7	0.12	16	329
Processing Fugitives Total	**10**	**0.24**	**32**	**674**	**15**	**0.37**	**50**	**1056**

iv. Transmission Fugitives

Transmission of Barnett Shale natural gas results in significant emissions of greenhouse gases and VOC. Greenhouse gas emissions from transmission fugitives are larger than from any other source category except compressor engine exhausts. Emissions of VOC in 2007 from transmission were approximately 18 tpd in 2007 and are estimated to be 28 tpd in 2009. Greenhouse gas emissions from methane fugitives result in emissions of approximately 5500 tpd in 2007 and 8600 tpd in 2009. Emissions are summarized in Table 20.

Table 20. Emissions from Natural Gas Transmission Fugitives.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Transmission Fugitives	12	0.29	181	3799	19	0.46	283	5952
Outside Metro Transmission Fugitives	5.5	0.13	82	1718	8.6	0.21	128	2691
Transmission Fugitives Total	**18**	**0.43**	**262**	**5517**	**28**	**0.67**	**411**	**8643**

4.3 All Sources Emission Summary

Emissions from all source categories in the Barnett Shale area are summarized in Table 21-1 on an annual average basis, and are summarized in Table 12-2 on a peak summer basis. Annual average emissions for 2009 of ozone and particulate precursors (NO_x and VOC) were approximately 191 tpd, and peak summer emissions of these compounds were 307 tpd. The portion of those emissions originating from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 133 tpd during the summer (Tarrant, Denton, Parker, Johnson, and Ellis).

Estimates of greenhouse gas emissions from the sector as a whole were quite large, with 2009 emissions of approximately 33,000 tpd. The greenhouse gas contribution from compressor engines was dominated by carbon dioxide, while the greenhouse gas contribution from all other sources was dominated by methane. Emissions of HAPs were significant from Barnett Shale activities, with emissions in 2009 of 6.4 tpd in 2009 on an annual average, and peak summer emissions of 17 tpd.

Table 21. Emissions Summary for All Source Categories.

Table 21-1. Annual Average Emissions from All Sources.

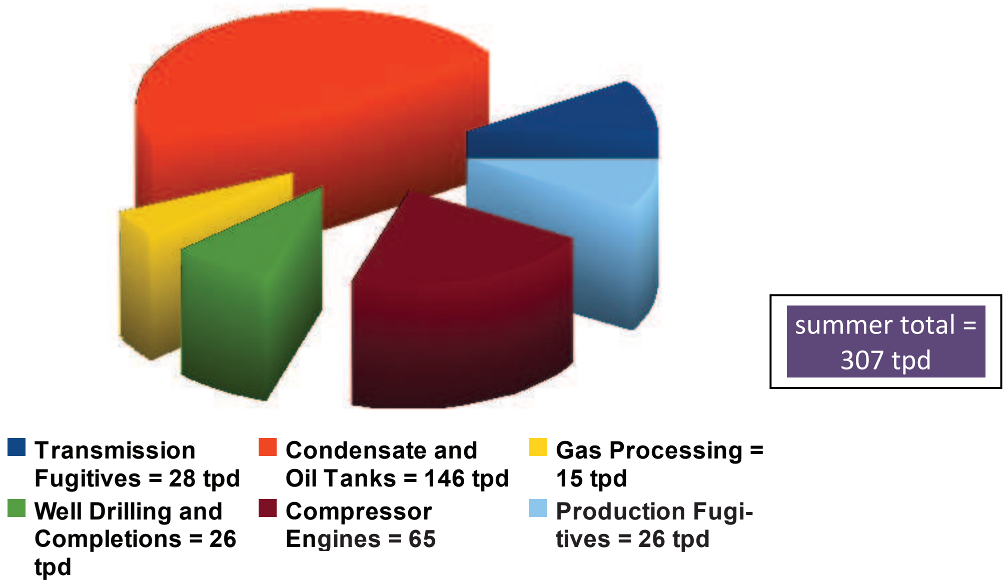
	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	**VOC**	**HAPs**	**CH4**	**CO2e**	**NOx**	**VOC**	**HAPs**	**CH4**	**CO2e**
Compressor Engine Exhausts	51	15	2.7	43	8910	46	19	3.6	61	13877
Condensate and Oil Tanks	0	19	0.39	4.5	95	0	30	0.60	7.0	149
Production Fugitives	0	17	0.40	148	3118	0	26	0.62	232	4884
Well Drilling and Completions	5.5	21	0.49	183	4061	5.5	21	0.49	183	4061
Gas Processing	0	10	0.24	32	674	0	15	0.37	50	1056
Transmission Fugitives	0	18	0.43	262	5517	0	28	0.67	411	8643
Total Daily Emissions (tpd)	**56**	**100**	**4.6**	**673**	**22375**	**51**	**139**	**6.4**	**945**	**32670**

Table 21-2. Peak Summer Emissions from All Sources.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	**VOC**	**HAPs**	**CH4**	**CO2e**	**NOx**	**VOC**	**HAPs**	**CH4**	**CO2e**
Compressor Engine Exhausts	51	15	2.7	43	8910	46	19	3.6	61	13877
Condensate and Oil Tanks	0	93	7.2	15	308	0	146	11	23	483
Production Fugitives	0	17	0.40	148	3118	0	26	0.62	232	4884
Well Drilling and Completions	5.5	21	0.49	183	4061	5.5	21	0.49	183	4061
Gas Processing	0	10	0.24	32	674	0	15	0.37	50	1056
Transmission Fugitives	0	18	0.43	262	5517	0	28	0.67	411	8643
Total Daily Emissions (tpd)	**56**	**174**	**11**	**683**	**22588**	**51**	**255**	**17**	**961**	**33004**

Emissions of nitrogen oxides from oil and gas production in the Barnett Shale were dominated by emissions from compressor engines, with a smaller contribution from well drilling and fracing pump engines. All source categories in the Barnett Shale contributed to VOC emissions, but the largest group of VOC sources was condensate tank vents. Figure 6 presents the combined emissions of NO_x and VOC during the summer from all source categories in the Barnett Shale.

Figure 6. Summer Emissions of Ozone & Fine Particulate Matter Precursors (NO_x and VOC) from Barnett Shale Sources in 2009.



4.4 Perspective on the Scale of Barnett Shale Air Emissions

Barnett Shale oil and gas production activities are significant sources of air emissions in the north-central Texas area. To help put the levels of Barnett Shale emissions into context, recent government emissions inventories for the area were reviewed, and emission rates of smog precursor emissions were examined.

The Dallas-Fort Worth area is home to two large airports, Dallas Love Field and Dallas-Fort Worth International Airport, plus a number of smaller airports. A recent emissions inventory has estimated 2009 NO_x emissions from all area airports to be approximately 14 tpd, with VOC emissions at approximately 2.6 tpd, resulting in total ozone and particulate matter precursor emissions of approximately 16 tpd. [22-24] For comparison, emissions of VOC + NO_x in summer 2009 from just the compressor engines in the Barnett Shale area will be approximately 65 tpd, and summer condensate tanks emissions will be approximately 146 tpd. In 2009, even after regulatory efforts to reduce NO_x emissions from certain compressor engine types, Barnett Shale oil and gas emissions will be many times the airports' emissions.

Recent state inventories have also compiled emissions from on-road mobile sources like cars, trucks, etc., in the 9-county D-FW metropolitan area.[25] By 2009, NO_x + VOC emissions from mobile sources in the 9-county area were estimated by the TCEQ to be approximately 273 tpd. The portion of on-road motor vehicle emissions from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 121 tpd (Denton, Tarrant, Parker, Johnson, and Ellis). As indicated earlier, summer oil and gas emissions in the 5-counties of the D-FW metropolitan area with significant oil and gas production was estimated to be 165 tpd, indicating that the oil and gas sector likely has greater emissions than motor vehicles in these counties (165 vs. 121 tpd).

Emissions of NO_x and VOC in the summer of 2009 from all oil and gas sources in the Barnett Shale 21-county area will exceed emissions from on-road mobile sources in the D-FW metropolitan area by more than 30 tpd (307 vs. 273 tpd).

Figure 7 summarizes summer Barnett Shale-related emissions, plus TCEQ emission estimates from the airports and on-road mobile sources. Figure 8 presents annual average emissions from these sources.

Figure 7. Barnett Shale Activity, D-FW Area Airports, & Mobile Sources (Summer 2009 Emissions).

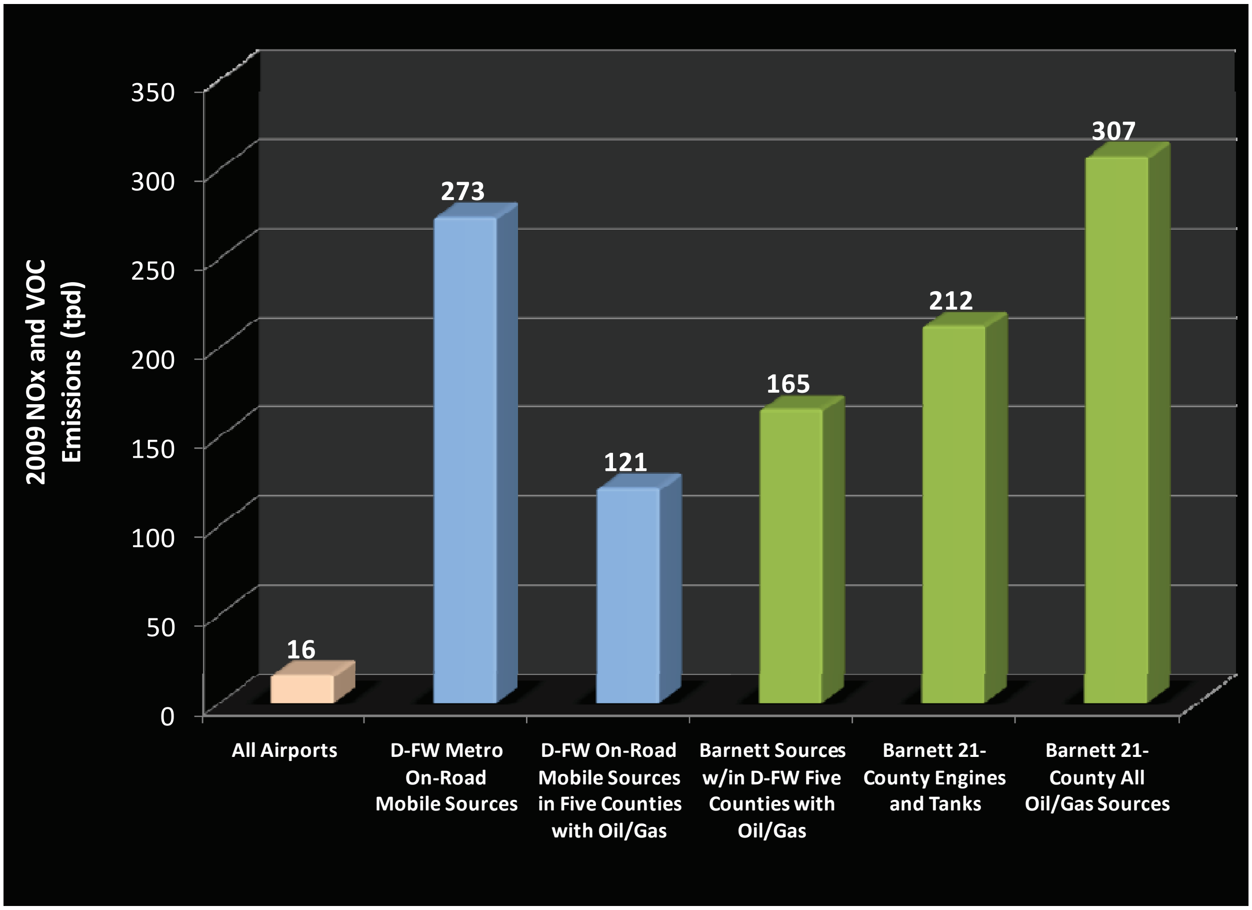
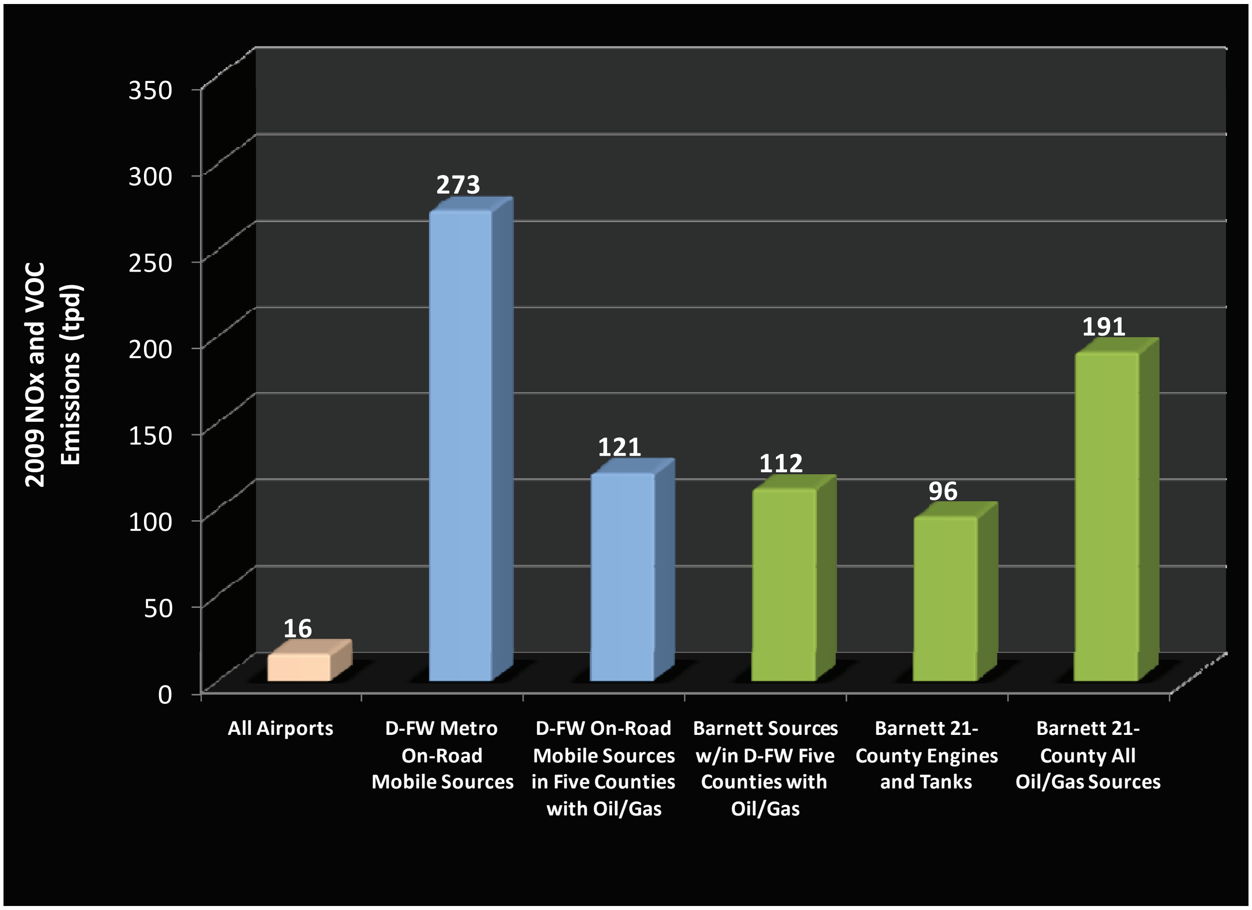


Figure 8. Barnett Shale Activity, D-FW Area Airports, & Mobile Sources (Annual Average 2009 Emissions).



5.0 EMISSIONS REDUCTION OPPORTUNITIES

The previous sections of this report have estimated the emission rates of ozone and particulate matter precursor compounds, air toxic compounds, and greenhouse gases from different oil and gas sources in the Barnett Shale area. For several of these source categories, off-the-shelf options are available which could significantly reduce emissions, resulting in important air quality benefits. Some of these emissions reductions would also result in increased production of natural gas and condensate, providing an economic payback for efforts to reduce emissions.

5.1 Compressor Engine Exhausts

Compressors in oil and gas service in the Barnett Shale perform vital roles, to either help get oil and gas out of the shale, to increase pressures of gas at the surface, and to provide the power for the large interstate pipeline systems that move high volumes of gas from production to processing and to customers. At present, most of the work to operate the compressors comes from natural gas-fired internal combustion engines, and these engines can be significant sources of emissions.

New TCEQ rules are scheduled to become effective in early 2009 and they will reduce NO_x, VOC, and other emissions from a subset of the engines in the Barnett Shale – those that are currently in the D-FW metropolitan area that had typically not reported into the Texas point source emissions inventory for major sources. These rules are a good first step in addressing emissions from these sources, which had previously gone unnoticed in state emission inventory and regulatory efforts.

However, engines outside the D-FW metropolitan area are not subject to the rule. And even within the metropolitan area, the rule will not have the effect of greatly reducing emissions in 2009 compared to 2007 levels, since growth in oil and gas production (and the new engines that are going to be required to power the growth) will begin to overtake the benefits that come from reducing emissions from the pre-2009 fleet (see Table 14).

Two available options for reducing emissions from engines in the Barnett Shale area are: (1) extending the TCEQ 2009 engine regulation to all engines in the Barnett Shale, and (2) replacing internal combustion engines with electric motors as the sources of compression power.

i. Extending the 2009 Engine Rule to Counties Outside the D-FW Metropolitan Area

Regulations adopted by TCEQ for the D-FW metropolitan area and scheduled to take effect in early 2009 will limit NO_x emissions from engines larger than 50 horsepower.[7] Rich burn engines will be restricted to 0.5 g/hp-hr, lean burn engines installed or moved before June 2007 will be restricted to 0.7 g/hp-hr, and lean burn engines installed or moved after June 2007 will be limited to 0.5 g/hp-hr. Applying these rules to engines outside the metropolitan area would reduce 2009 NO_x emissions from a large number of engines, in particular, rich burn engines between 50 to 500 hp. Emissions of NO_x in 2009 from the engines outside the metropolitan area would drop by approximately 6.5 tpd by extending the D-FW engine rule, an amount greater than mobile source emissions in all of Johnson County (4 tpd), or more than 50% of the emissions from Dallas-Fort Worth International Airport (12.6 tpd).

Extending the D-FW engine rule to counties outside the metropolitan area would likely result in many engine operators installing NSCR systems on rich burn engine exhausts. These systems would not only reduce emissions of NO_x, but they would also be expected to reduce emissions of VOC, the other ozone and particulate matter precursor, by approximately 75% or greater.[26a] Additional co-benefits of NSCR installations would include lower emissions of organic HAP compounds like benzene and formaldehyde, lower emissions of methane, and lower emissions of carbon monoxide. The level of HAP, methane, and carbon monoxide control would also be expected to be 75% or greater with typical NSCR installations.[26a]

Analyses of NSCR installations and operating costs by numerous agencies have indicated that the technology is very cost effective. For example, the Illinois Environmental Protection Agency estimated in 2007 that NSCR could control NO_x from 500 hp engines at approximately $330/ton.[26b] The U.S. EPA in 2006 estimated that NSCR could control NO_x from 500 hp engines at approximately $92 to 105/ton.[27] A 2005 report examining emissions reductions from compressor engines in northeast Texas estimated NO_x cost effectiveness for NSCR at $112-183/ton and identified VOC reductions as an important co-benefit.[28] These costs are well under the cost effectiveness values of $10,000 to $20,000 per ton often used as upper limits in $PM_{2.5}$, ozone, and regional haze (visibility) regulatory programs. The simultaneous HAPs and methane removal that would occur with NSCR use provide further justification for extending the D-FW engine rule to counties outside the metropolitan area.

ii. Electric Motors Instead of Combustion Engines for Compressor Power

When considering NO_x, VOC, HAPs, and greenhouse gas emissions from compressor engines, it is important to understand that the work to move the gas in the pipelines is performed by the compressors, which by themselves produce no direct combustion emissions. The emissions come from the exhaust of the internal combustion engines, which are fueled with a small amount of the available natural gas. These engines provide the mechanical power to run the compressors. The 2007 TCEQ engine survey and the most recent point source emissions inventory indicate that installed compressor engine capacity throughout the Barnett Shale was approximately 1,400,000 hp in 2007, and capacity is likely to increase to over 2,100,000 hp by 2009.

As an alternative to operating the compressors in the Barnett Shale with millions of hp of natural gas burning-engines, the compressors could be operated with electrically-driven motors. The electrification of the wellhead and compressor station engine fleet in the Barnett Shale area has the potential to deliver significant reductions in emissions in North Central Texas. The use of electric motors instead of internal combustion engines to drive natural gas compressors is not new to the natural gas industry, and numerous compressors driven by electric motors are operational throughout Texas. Unfortunately, current regulations have not yet required their use in the Barnett Shale.

A few of the many examples of electrically-driven natural gas compressors, positive technical assessments, and industrial experience with their use in Texas and throughout the U.S., include:

- The Interstate Natural Gas Association of America: "One advantage of electric motors is they need no air emission permit since no hydrocarbons are burned as fuel. However, a highly reliable source of electric power must be available, and near the station, for such units to be considered for an application." [29]
- The Williams natural gas company: "The gas turbine and reciprocating engines typically use natural gas from the pipeline, where the electric motor uses power from an electric transmission line. Selection of this piece of equipment is based on air quality, available power, and the type of compressor selected. Typically electric motors are used when air quality is an issue." [30]
- JARSCO Engineering Corp.: "The gas transmission industry needs to upgrade equipment for more capacity. The new high-speed electric motor technology provides means for upgrading, at a fraction of the life cycle costs of conventional gas powered equipment."[31]
- Pipeline and Gas Journal, June 2007: "Important factors in favor of electric-driven compressor stations that should be considered in the feasibility analysis include the fact that the fuel gas for

gas turbine compressor stations will be transformed into capacity increase for the electrically-driven compressor station, and will therefore add revenue to this alternative..." [32]

- Prime mover example: Installations in 2007 at Kinder Morgan stations in Colorado of +10,000 hp electric-driven compressor units. [33]
- Wellhead example: Installations in Texas of wellhead capacity (5 to 400 hp) electrically-driven compressors. [34,35]
- Mechanical Engineering Magazine, December 1996: "Gas pipeline companies historically have used gas-fired internal-combustion engines and gas turbines to drive their compressors. However, this equipment emits nitrogen oxides....According to the Electric Power Research Institute, it is more efficient to send natural gas to a combined-cycle power plant to generate electricity transmitted back to the pipeline compressor station than to burn the natural gas directly in gas-fired compressor engines."[36]
- The Dresser-Rand Corporation: "New DATUM-C electric motor-driven compressor provides quiet, emissions free solution for natural gas pipeline applications – An idea whose time had come." [37]
- Occidental Oil and Gas Corporation: "Converting Gas-Fired Wellhead IC Engines to Electric Motor Drives: Savings $23,400/yr/unit." [38]

The use of an electric motor instead of a gas-fired engine to drive gas compression eliminates combustion emissions from the wellhead or compressor station. Electric motors do require electricity from the grid, and in so far as electricity produced by power plants that emits pollutants, the use of electric motors is not completely emissions free. However, electric motor use does have important environmental benefits compared to using gas-fired engines.

Modern gas-fired internal-combustion engines have mechanical efficiencies in the 30-35% range, values that have been relatively static for decades. It is doubtful that dramatic increases in efficiency (for example, to 80 or 90%) are possible anytime in the near future. This means that carbon dioxide emissions from natural gas-fired engines at wellheads and compressor stations are not likely to drop substantially because of efficiency improvements. In addition, the scrubbing technology that is used in some large industrial applications to separate CO_2 from other gases also is unlikely to find rapid rollout to the thousands of comparatively-smaller exhaust stacks at natural gas wellheads and compressor stations. The two facts combined suggest that the greenhouse gas impacts from using internal combustion engines to drive compressors are likely to be a fixed function of compression demand, with little opportunity for large future improvements.

In contrast, the generators of grid electric power are under increasing pressure to lower greenhouse gas emissions. Wind energy production is increasing in Texas and other areas. Solar and nuclear power projects are receiving renewed interest from investors and regulators. As the electricity in the grid is produced by sources with lower carbon dioxide emissions, so then the use of electric motors to drive natural gas pipelines becomes more and more climate friendly.

Stated another way, carbon dioxide emissions from gas-fired engines are unlikely to undergo rapid decreases in coming years, whereas the electricity for operating electric motors is at a likely carbon-maximum right now. Electric-powered compression has a long-term potential for decreased climate impact, as non-fossil fuel alternatives for grid electricity generation expand in the future.

Costs: Estimates were made of the costs were switching from IC engines to electric motors for compression. Costs at sites in the Barnett Shale are highly time and site specific, depending on the cost of electricity and the value of natural gas, the numbers of hours of operation per year, the number and sizes of compressors operated, and other factors.

For this report, sample values were determined for capital, operating and maintenance, and operating costs of 500 hp of either IC engine capacity or electric motor capacity for a gas compressor to operate for 8000 hours per year at a 0.55 load factor. Electric power costs were based on $8/month/kW demand charge, $0.08/kWh electricity cost, and 95% motor mechanical efficiency. Natural gas fuel costs were based on $7.26/MMBtu wellhead natural gas price and a BSFC of 0.0085 MMBtu/hp-hr.

With these inputs, the wellhead value of the natural gas needed to operate a 500 hp compressor with an IC engine for 1 year is approximately $136,000. This is lower than the costs for electricity to run a comparable electric motor, which would be approximately $174,000. In addition to these energy costs, it is important to also consider operating and maintenance (O&M) and capital costs. With an IC engine O&M cost factor of $0.016/hp in 2009 dollars, O&M costs would be approximately $35,000. With an electric motor O&M cost factor of $0.0036/kWh in 2009 dollars, O&M costs would be approximately $6200, providing a savings of nearly $30,000 per year in O&M costs for electrical compression, nearly enough to compensate for the additional energy cost incurred from the additional price premium on electricity in Texas compared to natural gas.

With an IC engine capital cost factor of $750/hp in 2009 dollars, the cost of a 500 hp compressor engine would be approximately $370,000. With an electric motor cost factor of $700/kW, the cost of 500 hp of electrically-powered compression would be approximately $260,000.

The combined energy (electricity or natural gas), O&M, and capital costs for the two options are shown in Table 22, assuming a straight 5-year amortization of capital costs. The data show that there is little cost difference in this example, with a slight cost benefit of around $12,000/year for generating the compression power with an electric motor instead of an IC engine. While this estimate would vary from site to site within the Barnett Shale, there appears to be cost savings, driven mostly by reduced initial capital cost, in favor of electrical compression in the Barnett Shale. In addition to the potential cost savings of electrical compression over engine compression, the lack of an overwhelming economic driver one way or the other allows the environmental benefits of electric motors over combustion engines to be the deciding factor on how to provide compression power in the area.

Table 22. Costs of IC Engine and Electric Motor Compression [example of 500 hp installed capacity].

	IC Engine ($/year)	Electric Motor ($/year)
energy (NG or electricity)	136,000	174,000
O&M	35,000	6,200
capital	74,000	52,000
Total	**245,000**	**232,000**

5.2 Oil and Condensate Tanks

Oil and condensate tanks in the Barnett Shale are significant sources of multiple air pollutants, especially VOC, HAPs, and methane. Multiple options exist for reducing emissions from oil and condensate tanks, including options that can result in increased production and revenue for well operators.[14] This section will discuss two of these options: flares and vapor recovery units.

i. Vapor Recovery Units

Vapor recovery units (VRU) can be highly effective systems for capturing and separating vapors and gases produced by oil and condensate tanks. Gases and vapors from the tanks are directed to the inlet side of a compressor, which increases the pressure of the mixture to the point that many of the moderate and higher molecular weight compounds recondense back into liquid form. The methane and other light gases are directed to the inlet (suction) side of the well site production compressors to join the main flow of natural gas being produced at the well. In this way, VRU use increases the total production of gas at the well, leading to an increase in gas available for metering and revenue production. In addition, liquids produced by the VRU are directed back into the liquid phase in the condensate tank, increasing condensate production and the income potential from this revenue stream. Vapor recovery units are estimated to have control efficiencies of greater than 98%.[14]

The gases and vapors emitted by oil and condensate tanks are significant sources of air pollutants, and the escape of these compounds into the atmosphere also reduces income from hydrocarbon production. With a wellhead value of approximately $7/MMBtu, the 7 tpd of methane that is estimated to be emitted in 2009 from condensate tanks in the Barnett Shale have a value of over $800,000 per year. Even more significantly, a price of condensate at $100/bbl makes the 30 tpd of VOC emissions in 2009 from the tanks in the Barnett Shale potentially worth over $10 million per year.

While flaring emissions from tanks in the Barnett Shale would provide substantial environmental benefits, especially in terms of VOC and methane emissions, capturing these hydrocarbons and directing them into the natural gas and condensate distribution systems would provide both an environmental benefit and a very large potential revenue stream to oil and gas producers.

ii. Enclosed Flares

Enclosed flares are common pollution control and flammable gas destruction devices. Enclosed flares get their name because the flame used to ignite the gases is generated by burner tips installed within the stack well below the top. The flames from enclosed flares are usually not visible from the outside, except during upset conditions, making them less objectionable to the surrounding community compared to open (unenclosed) flares.

Using a flare to control emissions from tanks involves connecting the vents of a tank or tank battery to the bottom of the flare stack. The vapors from oil and condensate tanks are sent to the flare, and air is also added to provide oxygen for combustion. The vapors and air are ignited by natural gas pilot flames, and much of the HAP, VOC, and methane content of the tank vapors can be destroyed. The destruction efficiency for flares can vary greatly depending on residence time, temperature profile, mixing, and other factors. Properly designed and operated flares have been reported to achieve 98% destruction efficiencies.

Applying 98% destruction efficiency to the Barnett Shale oil and condensate tanks emissions estimates shown in Table 16 results in potential emission reductions of 30 tpd of VOC, 0.6 tpd of HAPs, and 7 tpd of methane. These reductions are substantial and would provide large benefits to the ozone and PM precursor, HAPs, and greenhouse gas emission inventory of the Barnett Shale area. The use of flares, however, also has several drawbacks. One of these is that tank vapor flares need a continuous supply of pilot light natural gas, and reports have estimated pilot light gas consumption at around 20 scfh/flare.[14]

Table 23 presents a summary of the results of an economic analysis performed in 2006 by URS Corporation for using flares or vapor recovery units to control emissions from a tank battery in Texas.[14] Capital costs were estimated by URS with a 5-year straightline amortization of capital. Flow from the tank battery was 25Mscf/day and VOC emissions were approximately 211 tpy. Costs were in 2006 dollars.

Table 23. Economics of Flares and Vapor Recovery Units.

Control Option	Total Installed Capital Cost ($)	Annual Installed Operating Cost ($/yr)	Operating Cost ($/yr)	Value Recovered ($/yr)	VOC Destruction Cost Effectiveness ($/ton VOC)
Enclosed Flare	40,000	8000	900	NA	40
VRU	60,000	12000	11,400	91,300	($320)*

*VRU produces positive revenue, resulting in zero cost for VOC control, after accounting for value of recovered products.

The URS analysis indicated that flares were able to cost effectively reduce VOC emissions at $40/ton, while VRU units produced no real costs and quickly generated additional revenue from the products recovered by VRU operation. There was a less-than 1 year payback on the use of a VRU system, followed by years of the pollution control device becoming steady revenue source.

5.3 Well Completions

Procedures have been developed to reduce emissions of natural gas during well completions. These procedures are known by a variety of terms, including "the green flowback process" and "green completions." [39,40] To reduce emissions, the gases and liquids brought to the surface during the completion process are collected, filtered, and then placed into production pipelines and tanks, instead of being dumped, vented, or flared. The gas cleanup during a "green" completion is done with special temporary equipment at the well site, and after a period of time (days) the gas and liquids being produced at the well are directed to the permanent separators, tanks, and piping and meters that are installed at the well site. Green completion methods are not complex technology and can be very cost effective in the Barnett Shale. The infrastructure is well-established and gathering line placement for the initial collection of gas is not a substantial risk since wells are successfully drilled with a very low failure rate.

Emissions during well completions depend on numerous site-specific factors, including the pressure of the fluids brought to the surface, the effectiveness of on-site gas capturing equipment, the control efficiency of any flaring that is done, the chemical composition of the gas and hydrocarbon liquids at the drill site, and the duration of drilling and completion work before the start of regular production.

Some recent reports of the effectiveness of green completions in the U.S. are available, including one by the U.S. EPA which estimated 70% capture of formerly released gases with green completions, and another report by Williams Corporation which found that 61% to 98% of gases formerly released during well completions were captured with green completions.[40-41] Barnett Shale producer Devon Energy is using green completions on its wells, and they reported $20 million in profits from natural gas and condensate recovered by green completed wells in a 3 year period.[42]

If green completion procedures can capture 61% to 98% of the gases formerly released during well completions, the process would be a more environmentally friendly alternative to flaring of the gases, since flaring destroys a valuable commodity and prevents its beneficial use. Green completions would also certainly be more beneficial than venting of the gases, since this can release very large quantities of methane and VOCs to the atmosphere. Another factor in favor of capturing instead of flaring is that flaring can produce carbon dioxide (a greenhouse gas), carbon monoxide, polycyclic aromatic hydrocarbons, and particulate matter (soot) emissions.

5.4 Fugitive Emissions from Production Wells, Gas Processing, and Transmission

Fugitive emissions from the production wells, gas processing plants, gas compressors, and transmission lines in the Barnett Shale can be minimized with aggressive efforts at leak detection and repair. Unlike controlling emissions from comparatively smaller numbers of engines or tanks (numbering in the hundreds or low thousands per county), fugitive emissions can originate from tens of thousands of valves, flanges, pump seals, and numerous other leak points. While no single valve or flange is likely to emit as much pollution as a condensate tank or engine exhaust stack, the cumulative mass of all these fugitives can be substantial. There are readily-available measures that can reduce fugitive emissions.

i. Enhanced Leak Detection and Repair Program

The federal government has established New Source Performance Standards for natural gas processing plants a.k.a. NSPS Subpart KKK.[43] These standards require regularly scheduled leak detection, and if needed, repair activities for items such as pumps, compressors, pressure-relief valves, open-ended lines, vapor recovery systems, and flares. The NSPS applies to plants constructed or modified after January 20, 1984. The procedures and standards in the processing plant NSPS are generally based on the standards developed for the synthetic organic manufacturing chemicals industry.[44]

Fugitive emissions from oil and gas wells, separators, tanks, and metering stations are not covered by the processing plant NSPS. Nonetheless, the leak detection and repair protocols established in the NSPS could certainly be used to identify fugitive emissions from these other items. Leak detection at processing plants covered by the NSPS is performed using handheld organic vapor meters (OVMs), and inspections are required to be done on a specified schedule. These same procedures could be used at every point along the oil and gas system in the Barnett Shale to identify and reduce emissions of VOCs and methane. Doing so would reduce emissions, and by doing so, increase production and revenue to producers.

It is difficult to estimate the exact degree of emission reductions that are possible with fugitive emission reduction programs. The large and varied nature of fugitive emission points (valves, fittings, etc.) at production wells, processing plants, and transmission lines means that each oil and gas related facility in the Barnett Shale will have different options for reducing fugitive emissions. In general, leak detection and repair programs can help identify faulty units and greatly reduce their emissions.

ii. Eliminating Natural Gas-Actuated Pneumatic Devices

The State of Colorado is currently adopting and implementing VOC control strategies to reduce ambient levels of ozone in the Denver metropolitan area and to protect the numerous national parks and wilderness areas in the state. As part of this effort, the state investigated the air quality impacts of oil and gas development, including the impacts of the pneumatically-controlled valves and other devices that are found throughout gas production, processing, and transmission systems. The State of Colorado confirmed the basic conclusions arrived at earlier by EPA and GRI in 1995, that these pneumatic devices can be substantial sources of CH_4, VOC, and HAP emissions.[45,46] Much of the following information on these devices and the strategies to control emissions is based on a review of the recent work in Colorado.

Valves and similar devices are used throughout the oil and gas production, processing, and transmission systems to regulate temperature, pressure, flow, and other process parameters. These devices can be operated mechanically, pneumatically, or electrically. Many of the devices used in the natural gas sector are pneumatically operated. Instrument air (i.e. compressed regular air) is used to power pneumatic devices at many gas processing facilities, but most of the pneumatic devices at production wells and along transmission systems are powered by natural gas.[46] Other uses of pneumatic devices are for shutoff valves, for small pumps, and with compressor engine starters.

As part of normal operation, most pneumatic devices release or “bleed”gas to the atmosphere. The release can be either continuously or intermittently, depending on the kind of device. In 2003 U.S. EPA estimated that emissions from the pneumatic devices found throughout the production, processing, and transmission systems were collectively one of the largest sources of methane emissions in the natural gas industry. Some U.S. natural gas producers have reduced natural gas emissions significantly by replacing or retrofitting "high-bleed" pneumatic devices. High-bleed pneumatic devices emit at least 6 standard cubic feet gas per hour.[46] Actual field experience is demonstrating that up to 80 percent of all high-bleed devices in natural gas systems can be replaced or retrofitted with low-bleed equipment.

The replacement of high-bleed pneumatic devices with low-bleed or no-bleed devices can reduce natural gas emissions to atmosphere by approximately 88 or 98 percent, respectively.[21, 47] Anadarko Petroleum Corporation estimated that VOC emissions from their pneumatic devices will be reduced by 464 tpy once 548 of their pneumatic controllers are retrofitted in Colorado.[46]

It may not be possible, however, to replace all high-bleed devices with low or no bleed alternatives. In the state of Colorado, it was estimates that perhaps up to 20 percent of high-bleed devices could not be retrofitted or replaced with low-bleed devices. Some of these included very large devices requiring fast and/or precise responses to process changes which could not yet be achieved with low-bleed devices.

But even for these devices that appear to require high-bleed operation, alternatives are available. Natural gas emissions from both high bleed and low bleed devices can be reduced by routing pneumatic discharge ports into a fuel gas supply line or into a closed loop controlled system. Another alternative is replacing the natural gas as the pneumatic pressure fluid with pressurized air. Instrument pressurized air systems are sometimes installed at facilities that have a high concentration of pneumatic devices, full-time operator presence, and are on a power grid. In an instrument pressurized air system, atmospheric air is compressed, stored in a volume tank, filtered, and dried. The advantage of a pressurized air system for operating pneumatic devices is that operation is the same whether they air or natural gas is used. Existing pneumatic gas supply piping, control instruments, and valve actuators can be reused when converting from natural gas to compressed air.

The U.S. EPA runs a voluntary program, EPA Natural Gas STAR, for companies adopting strategies to reduce their methane emissions. Experience from companies participating in the program indicates that strategies to reduce emissions from pneumatic devices are highly cost effective, and many even pay for themselves in a matter of months.[46] EPA reports that one company replaced 70 high-bleed pneumatic devices with low-bleed devices and retrofitted 330 high-bleed devices, which resulted in an emission reduction of 1,405 thousand cubic meters per year. At $\$105/m^3$, this resulted in a savings of $148,800 per year. The cost, including materials and labor for the retrofit and replacement, was $118,500, and therefore, the payback period was less than one year. Early replacement (replacing prior to projected end-of-service-life) of a high-bleed valve with a low-bleed valve is estimated to cost $1,350. Based on $\$3/m^3$ gas, the payback was estimated to take 21 months. For new installations or end of service life replacement, the incremental cost difference of high-bleed devices versus low-bleed devices was $150 to $250. Based on $3 per Mcf gas, the payback was estimated to take 5 to 12 months.[46]

Overall, cost-effective strategies are available for reducing emissions and enhance gas collection from pneumatic devices in Barnett Shale area operations. These strategies include:

- Installing low- or no-bleed pneumatic devices at all new facilities and along all new transmission lines;
- Retrofitting or replacing existing high-bleed pneumatic devices with low- or no-bleed pneumatic devices;
- Ensuring that all natural gas actuated devices discharge into sales lines or closed loops, instead of venting to the atmosphere;
- Using pressurized instrument air as the pneumatic fluid instead of natural gas.

6.0 CONCLUSIONS

Oil and gas production in the Barnett Shale region of Texas has increased rapidly over the last 10 years. The great financial benefits and natural resource production that comes from the Barnett Shale brings with it a responsibility to minimize local, regional, and global air quality impacts. This report examined emissions of smog forming compounds, air toxic compounds, and greenhouse gases from oil and gas activity in the Barnett Shale area, and identified methods for reducing emissions.

Emissions of ozone and fine particle smog forming compounds (NOx and VOC) will be approximately 191 tons per day on an annual average basis in 2009. During the summer, VOC emissions will increase, raising the NOx + VOC total to 307 tpd, greater than the combined emissions from the major airports and on-road motor vehicles in the D-FW metropolitan area.

Emissions in 2009 of air toxic compounds from Barnett Shale activities will be approximately 6 tpd on an annual average, with peak summer emissions of 17 tpd.

Emissions of greenhouse gases like carbon dioxide and methane will be approximately 33,000 CO_2 equivalent tons per day. This is roughly comparable to the greenhouse gas emissions expected from two 750 MW coal-fired power plants.

Cost effective emission control methods are available with the potential to significantly reduce emissions from many of the sources in the Barnett Shale area, including

- the use of "green completions" to capture methane and VOC compounds during well completions,
- phasing in of electric motors as an alternative to internal-combustion engines to drive gas compressors,
- the control of VOC emissions from condensate tanks with vapor recovery units, and
- replacement of high-bleed pneumatic valves and fittings on the pipeline networks with no-bleed alternatives.

Large reductions in greenhouse gas emissions could be achieved through the use of green completion methods on all well completions, with the potential to eliminate almost 200 tpd of methane emissions while increasing revenue for producers by recovering saleable gas. In addition, the replacement of internal combustion engines with electric motors for compression power could reduce smog-forming emissions in the D-FW metropolitan area by 65 tpd. Significant emission reductions could also be achieved with the use of vapor recovery units on oil and condensate tanks, which could eliminate large amounts of VOC emissions. Vapor recovery units on condensate tanks would pay for themselves in a matter of months by generating additional revenue to producers from the gas and condensate that would be captured instead of released to the atmosphere. Fugitive emissions of methane, VOC, and HAPs could be reduced with a program to replace natural gas actuated pneumatic valves with units actuated with compressed air. For those devices in locations where compressed air is impractical to implement, connection of the bleed vents of the devices to sales lines also could greatly reduce emissions.

There are significant opportunities available to improve local and regional air quality and reduce greenhouse gas emissions by applying readily available methods to oil and gas production activities in the Barnett Shale.

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Author's Notes:

A draft version of this report was prepared in September 2008 and distributed for review and comment to oil and gas producers, state and federal regulators, authors of some of the references used in this report, and others. The author appreciates the comments received by those reviewers and the time they took to provide feedback. For the purpose of full disclosure, the author notes that he was an employee with Radian International LLC working on projects for several gas industry clients, including the Gas Research Institute and gas pipeline companies, during the time that "Methane Emissions from the Natural Gas Industry" (Reference 15) was published. The authors of Reference 15 were also employees of Radian International LLC, working as contractors for the Gas Research Institute and the Environmental Protection Agency. The author of this study notes that he did not work on or participate in the GRI/EPA project performed by the other Radian International personnel.

Images on the cover page from the Texas Railroad Commission and the U.S. Department of Energy.

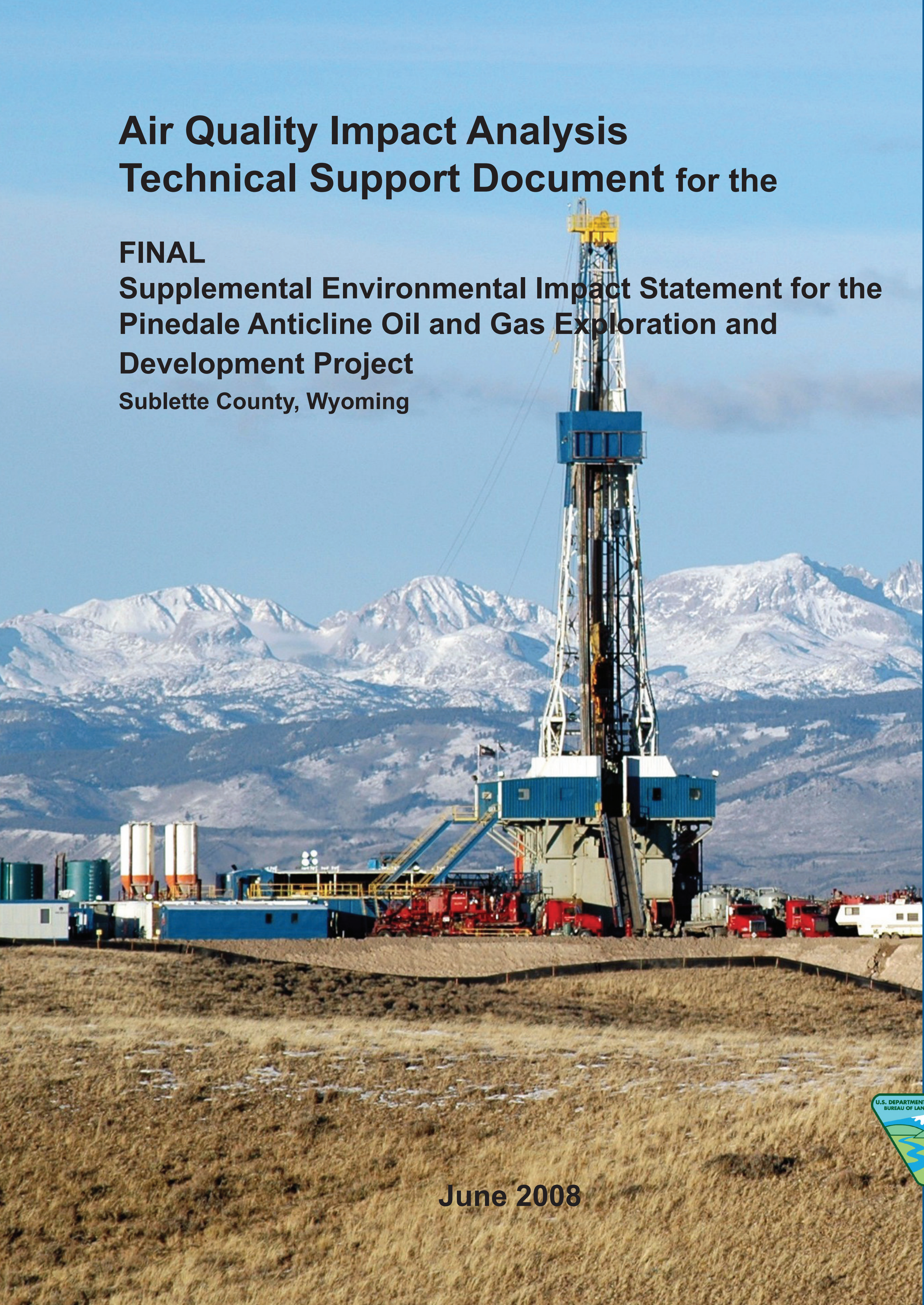
Some typos and spreadsheet errors fixed on 2/8/2009.

Finally, the statements and recommendations in this study are those of the author, and do not represent the official positions of Southern Methodist University.

Air Quality Impact Analysis Technical Support Document for the

FINAL
Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project

Sublette County, Wyoming



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

June 2008

2.0 EMISSIONS INVENTORY

2.1 PROJECT EMISSIONS

The direct project emissions inventory for the PAPA is divided into four sections in Appendix:

- 2005 Actual Emissions Inventory (Section.1),
- 2005 Potential Emissions Inventory (Section 2),
- Proposed Action Emissions Inventory (Section 3), and
- No Action Emissions Inventory (Section 4).

Calculation methods are similar for each emissions inventory except as noted in the following sections. Specific details for each inventory are provided in the respective sections of Appendix F.

Criteria pollutant and hazardous air pollutant (HAP) emissions were inventoried for construction activities, production activities, and ancillary facilities. Criteria pollutants included nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOCs), particulate matter less than 10 microns in diameter (PM_{10}), and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). HAPs consist of n-hexane; benzene, toluene, ethylbenzene, and xylene (BTEX); and formaldehyde. All emission calculations were completed in accordance with WDEQ-AQD oil and gas guidance (WDEQ-AQD 2001), WDEQ-AQD additional guidance for the Jonah and Pinedale Anticline Gas Fields (WDEQ-AQD 2004), stack test data, EPA's AP-42, or other accepted engineering methods (see Appendix F, Section1). Actual 2005 emissions were obtained from emissions inventories submitted by PAPA Operators to WDEQ-AQD, when available. Emissions not quantified in these inventories were conservatively assumed to be equal to those calculated for the 2005 potential emissions inventory.

2.1.1 Construction Emissions

Construction activities are a source of primarily criteria pollutants. Emissions would occur from construction (well pads, roads, gathering pipelines, and ancillary facilities), drilling, completion/testing, traffic, and wind erosion. Well development rates were provided by the Operators based on their future projections for both the Proposed Action Alternative and the No Action Alternative. These well development rates vary by alternative. Detailed well development rates per year can be found in the tables of Appendix F.

Emissions from construction of well pads and roads and traffic include fugitive PM_{10} and $PM_{2.5}$. Other criteria pollutant emissions would occur from diesel combustion in haul trucks and heavy construction equipment. On well pads and resource roads, water would be used for fugitive dust control, with a control efficiency of 50%. On local roads, magnesium chloride would be used for dust control, with a control efficiency of 85%.

After the well pad is constructed, rig-move/drilling would begin. Emissions would include fugitives from unpaved road travel to and from the drilling site. There would be emissions from diesel drilling engines and from boilers in the winter months. Emissions from well completion and testing would include fugitive PM_{10} and $PM_{2.5}$ from traffic. It would also include combustion emissions from diesel fracturing engines and haul truck tailpipes. All completions would be "green completions" with no flaring other than for upset/emergency conditions.

Pollutant emissions would also occur from gathering pipeline installation activities, including general construction activities, travel to and from the pipeline construction site, and diesel combustion from on-site construction equipment.

Construction emission calculations are provided in detail, showing all emission factors, input parameters, and assumptions, in Appendix F.

2.1.2 Production Emissions

Field production equipment and operations would be a source of criteria pollutants and HAPs including BTEX, n-hexane, and formaldehyde. Pollutant emission sources during field production would include:

- combustion engine emissions and fugitive dust from road travel to and from production sites;
- diesel combustion emissions from haul trucks;
- combustion emissions from production site heaters;
- fugitive VOC/HAP emissions from production site equipment leaks;
- condensate storage tank flashing and flashing control;
- glycol dehydrator still vent flashing;
- wind erosion from well pad disturbed areas
- processing units at gas plants; and
- natural gas-fired reciprocating internal combustion compressor engines

Fugitive PM_{10} and $PM_{2.5}$ emissions would occur from road travel and wind erosion from well pad disturbances. Criteria pollutant emissions would occur from diesel combustion in haul trucks traveling in the field during production.

Heaters required at production facilities include separator/indirect line heaters and dehydrator reboiler heaters. These heaters are sources of mainly NO_x and CO as well as small amounts of VOCs. Emissions from these sources were calculated on run-time percentages for both the summer and winter seasons based on data provided by Operators.

VOC and HAP emissions would occur from fugitive equipment leaks (i.e., valves, flanges, connections, pump seals, and opened lines). Condensate storage tank flashing and glycol dehydrator still vent flashing emissions also would include VOC/HAP emissions. VOC and HAP emissions would decrease over the life of an individual well due to declines in condensate and gas production. Emissions from these sources were based on information provided by Operators.

Production emission calculations are provided in detail, showing all emission factors, input parameters, and assumptions, in Appendix F.

2.1.3 Total Field Emissions

Estimates of maximum potential annual emissions in the PAPA under the No Action and Proposed Action alternatives, and for year 2005 are shown in Table 2.1. Maximum potential annual emissions assume construction and production occurring simultaneously in the field for the maximum emissions year for each project alternative.

Table 2.1 Estimated Potential Emissions by Alternative (tpy), Pinedale Anticline Project.

Source	Pollutant	Year 2005	Alternative A (No Action) 2007	Alternative B (Proposed Action) 2009
Construction Emissions				
Drill Rigs	NO_x	2590.9	4066.5	3232.6
	CO	2031.6	2445.2	2307.0
	SO_2	221.0	48.5	55.7
	PM_{10}	133.5	160.4	130.3
	$PM_{2.5}$	133.5	160.4	130.3
	VOC	244.5	292.9	271.3
Fugitives	NO_x	427.4	641.8	559.4
(Pad/Road Construction, Traffic, Completions, etc...)	CO	305.3	493.5	428.1
	SO_2	10.6	15.6	14.4
	PM_{10}	682.2	712.6	415.9
	$PM_{2.5}$	144.8	143.7	82.7
	VOC	192.9	66.1	57.0
Production Emissions				
Compression:	NO_x	421.9	472.2	532.1
	CO	157.7	175.7	235.5
	SO_2	0.0	0.0`	0.0
	PM_{10}	0.0	0.0	0.0
	$PM_{2.5}$	0.0	0.0	0.0
	VOC	320.5	353..5	357.1
Granger Gas Plant	NO_x	301.7	301.7	301.7
(Expansion)	CO	322.8	322.8	322.8
	SO_2	0.0	0.0	0.0
	PM_{10}	0.0	0.0	0.0
	$PM_{2.5}$	0.0	0.0	0.0
	VOC	140.2	140.2	140.2
Wind Erosion	PM_{10}	254.8	357.2	440.8
	$PM_{2.5}$	101.9	142.9	176.3
Fugitives	NO_x	72.2	119.8	108.8
(Heaters, dehys, tanks, traffic, other production equipment, etc…)	CO	251.1	318.7	54.8
	SO_2	0.2	0.5	0.6
	PM_{10}	128.5	311.7	73.7
	$PM_{2.5}$	21.2	51.3	17.8
	VOC	1736.5	1396.2	1150.7
Total	NO_x	3512.4	5602.0	4734.6
	CO	2745.7	3755.9	2978.3
	SO_2	231.8	64.6	70.7
	PM_{10}	1199.0	1541.9	1060.7
	$PM_{2.5}$	401.4	498.3	407.1
	VOC	2494.4	2248.9	1976.3

Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado

Colorado Air Pollution Control Division

<u>Revised Regional Haze Plan</u>
Air Quality Control Commission, approved 01/07/2011

Table of Contents

Preface/Disclaimer

The following document contains Colorado's State Implementation Plan for Regional Haze. Unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described. Many of these controls are neither being submitted to EPA for approval nor being incorporated into the SIP as federally enforceable measures and are mentioned only as examples or references to Colorado air quality programs.

In developing and updating its Long Term Strategy (LTS) for reasonable progress, the State of Colorado takes into account the visibility impacts of several ongoing state programs that are not federally enforceable. These include statewide Colorado requirements applying to open burning, wildland fire smoke management, and renewable energy.

References in this SIP revision to such programs are intended to provide information that Colorado considers in developing its LTS and in its reasonable progress process. These programs are neither being submitted for EPA approval, nor for incorporation into the SIP by reference, nor are they intended to be federally enforceable. The Air Quality Control Commission Rules that govern them implement Colorado's programs and are not federally required. The state is precluded from submitting such programs for incorporation into this SIP by 25-7-105.1, C.R.S.

The following dates reflect actions by the Air Quality Control Commission associated with Colorado State Implementation Plan for Regional Haze:

Regional Haze Plan	Approval Date
Original	12/21/2007
First Revision	12/19/2008
Second Revision (Fully Replaces All Previous RH Plans)	01/07/2011

Chapter 1 Overview

1.1 Introduction

The Clean Air Act (CAA) defines the general concept of protecting visibility in each of the 156 Mandatory Class I Federal Areas across the nation. Section 169A from the 1977 CAA set forth the following national visibility goal:

> "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution."

The federal visibility regulations (40 CFR Part 51 Subpart P – Visibility Protection 51.300 - 309) detail a two-phased process to determine existing impairment in each of the Class I areas; how to remedy such impairment; and how to establish goals to restore visibility to 'natural conditions' by the year 2064. The federal regulations require states to prepare a State Implementation Plan (SIP) to:

- include a monitoring strategy
- address existing impairment from major stationary facilities (Reasonably Attributable Visibility Impairment)
- prevent future impairment from proposed facilities
- address Best Available Retrofit Technology (BART) for certain stationary sources
- consider other major sources of visibility impairment
- calculate baseline current and natural visibility conditions
- consult with the Federal Land Managers (FLMs) in the development or change to the SIP
- develop a long-term strategy to address issues facing the state
- set and achieve reasonable progress goals for each Class I area
- review the SIP every five years

Phase 1 of the visibility program, also known as Reasonably Attributable Visibility Impairment (RAVI), addresses impacts in Class I areas by establishing a process to evaluate source specific visibility impacts, or *plume blight*, from individual sources or small groups of sources. Part of that process relates to evaluation of sources prior to construction through the Prevention of Significant Deterioration (PSD) permit program looking at major stationary sources. The plume blight part of the Phase 1 program also allows for the evaluation, and possible control, of reasonably attributable impairment from existing sources.

Section 169B was added to the Clean Air Act Amendments of 1990 to address Regional Haze. Since Regional Haze and visibility problems do not respect state and tribal boundaries, the amendments authorized EPA to establish visibility transport regions as a way to combat regional haze.

Phase 2 of the visibility program addresses Regional Haze. This form of visibility impairment focuses on overall decreases in visual range, clarity, color, and ability to discern texture and details in Class I areas. The responsible air pollutants can be generated in the local vicinity or carried by the wind often many hundreds or even thousands of miles from where they originated. For technical and legal reasons the second part of the visibility program was not implemented in regulation until 1999. In 1999 the EPA finalized the Regional Haze Rule (RHR) requiring States to adopt a State Implementation Plans (SIPs) to address this other aspect of visibility impairment in the Class I areas. Under current rules the Regional Haze SIP were to be submitted to the EPA by December 31st, 2007. Colorado adopted key components of the Regional Haze SIP in 2007 and 2008 which were submitted to EPA in 2008 and 2009, respectively. EPA subsequently noted deficiencies in the BART determination and Reasonable Further Progress elements, as well as other, more minor issues. Colorado has proceeded to take steps to remedy these alleged deficiencies. This SIP addresses EPA's concerns. Updates to the BART evaluations and Reasonable Further Progress analyses constitute the major revisions to this 2010 plan. In addition, revisions to other chapters have been made to update emissions and monitoring data and descriptions of program changes impacting emissions regulations favoring improved visibility in the State.

The Regional Haze Rule envisions a long period, covered by several planning phases, to ultimately meet the congressionally established National Visibility Goal targeted to be met in 2064. Thus, the approach taken by Colorado, and other states, in preparing the plan is to set this initial planning period (2007-2018) as the "foundational plan" for the subsequent planning periods. This is an important concept when considering the nature of this SIP revision as compared to a SIP revision developed to address a nonattainment condition. The nonattainment plan must demonstrate necessary measures are implemented to meet the NAAQS by a specific time. On the other hand, the Regional Haze SIP must, among other things, set a Reasonable Progress Goal for each Class I area to protect the best days and to improve visibility on the worst days during the applicable time period for this SIP (2007-2018).

Colorado developed, and EPA approved, a SIP for the first Phase 1 of the visibility program. This Plan updates Phase 1 as well as establishing Phase 2 of the program, Regional Haze. The two key requirements of the Regional Haze program are:

- Improve visibility for the most impaired days, and
- Ensure no degradation in visibility for the least impaired days.

Though national visibility goals are targeted to be achieved by the year 2064,this plan is designed to meet the two requirements stated above for the period ending in 2018 (the first planning period in the federal rule), while also establishing enforceable controls to that will help to address the long term goal.

This SIP is intended to meet the requirements of EPA's Regional Haze rules that were adopted to comply with requirements set forth in the Clean Air Act. Elements of this Plan address the core requirements pursuant to 40 CFR 51.308(d) and the Best Available Retrofit Technology (BART) components of 40 CFR 50.308(e). In addition, this SIP addresses Regional Planning, State/Tribe and Federal Land Manager coordination, and contains a commitment to provide Plan revisions and adequacy determinations.

1.2 Visibility Impairment

Most visibility impairment occurs when pollution in the form of small particles scatter or absorb light. Air pollutants come from a variety of natural and anthropogenic sources. Natural sources can include windblown dust and smoke from wildfires. Anthropogenic sources can include motor vehicles and other transportation sources, electric utility and industrial fuel burning, minerals, oil and gas extraction and processing and manufacturing operations. More pollutants mean more absorption and scattering of light which reduces the clarity and color of a scene. Some types of particles such as sulfates scatter more light, particularly during humid conditions. Other particles like elemental carbon from combustion processes are highly efficient at absorbing light. Commonly, the receptor is the human eye and the object may be a single viewing target or a scene.

In the 156 Class I areas across the country, visual range has been substantially reduced by air pollution. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles. In the West, visual range has decreased from an average of 140 miles to 35-90 miles. Colorado has some of the best visibility in the West but also has a number of areas where visibility is impaired due to a variety of sources. This SIP is designed to address regional haze requirements for the twelve mandatory Federal Class I areas in Colorado.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are transported many miles from the source of the pollutants. Some haze forming pollutants are also linked to human health problems and other environmental damage. Exposure to increased levels of very small particles in the air has been linked with increased respiratory illness, decreased lung function, and premature death. In addition, particles such as nitrates and sulfates contribute to acid deposition potentially making lakes, rivers, and streams less suitable for some forms of aquatic life and impacting flora in the ecosystem. These same acid particles can also erode materials such as paint, buildings or other natural and manmade structures.

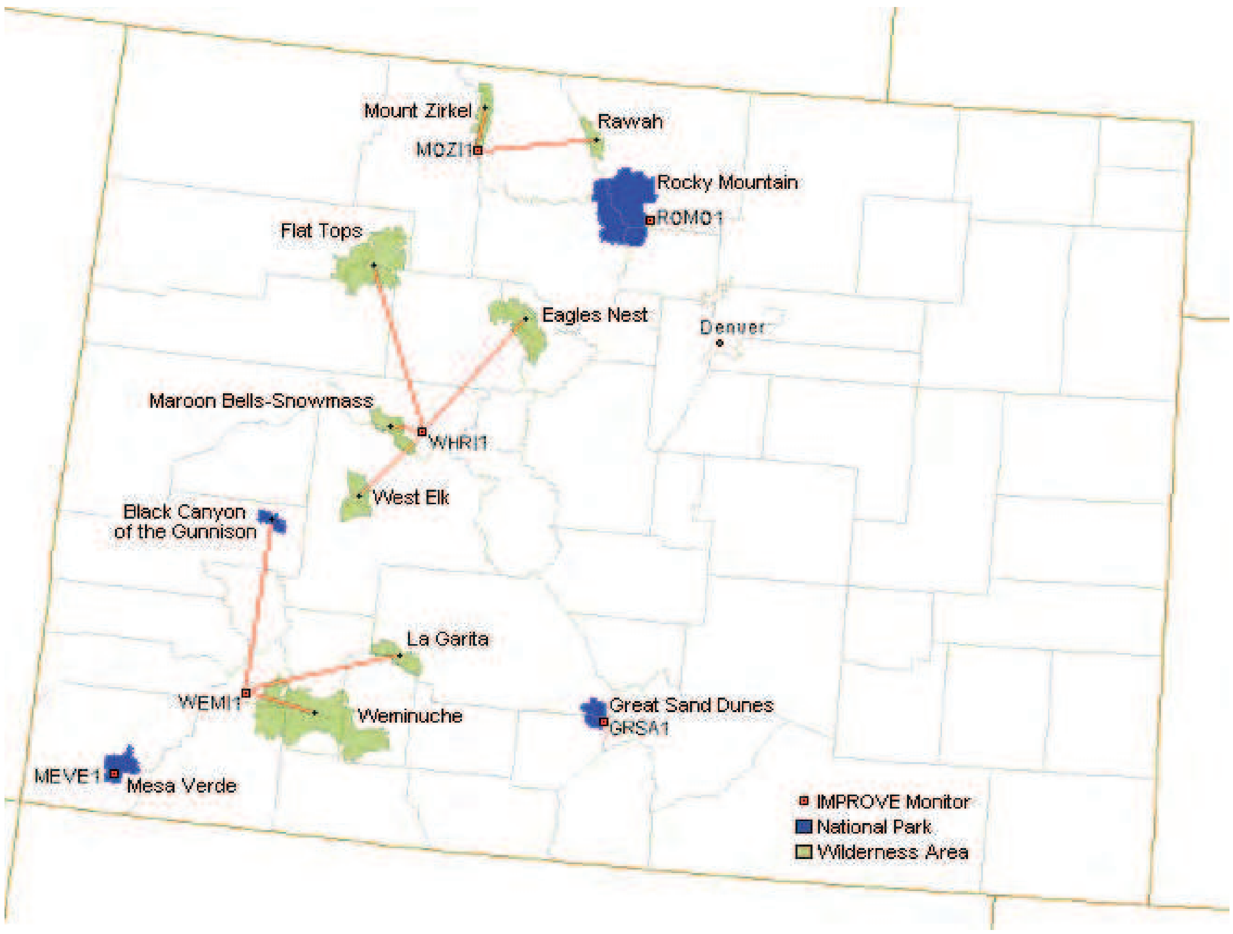
1.3 Description of Colorado's Class I Areas

There are 12 Mandatory Federal Class I Areas in the State of Colorado:

Black Canyon of the Gunnison National Park
Eagles Nest Wilderness Area
Flat Tops Wilderness Area
Great Sand Dunes National Park
La Garita Wilderness Area
Maroon Bells-Snowmass Wilderness Area
Mesa Verde National Park
Mount Zirkel Wilderness Area
Rawah Wilderness Area
Rocky Mountain National Park
Weminuche Wilderness Area
West Elk Wilderness Area

A detailed description of each of these areas, along with photographs, summaries of monitoring data containing an overview of current visibility conditions and sources of pollution in each area, is contained in individual Technical Support Documents (TSDs) for this plan (see list in Chapter 10). Each Class I area has been designated as impaired for visual air quality by the Federal Land Manager responsible for that area. Under the federal visibility regulations, the Colorado visibility SIP needs to address the visibility status of and control programs specific to each area. Figure 1-1 shows the location of these areas and the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring site that measures particulate air pollution representative of each Class I area.

Figure 1-1 Colorado Class I Areas and IMPROVE Monitor Locations



1.4 Programs to Address Visibility Impairment

Colorado adopted a Phase 1 visibility SIP to address the PSD permitting, source specific haze, and plume blight aspects of visibility in 1987. The most recent plan update was approved by the EPA in December 2006.

As stated in the preface to this Plan, unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described and are neither being submitted to EPA for approval nor being incorporated into the SIP as Federally enforceable measures. This comprehensive visibility plan, which now contains both Phase 1 and Phase 2 visibility requirements, addresses all aspects of Colorado's visibility improvement program. Colorado has numerous emission control programs to improve and protect visibility in Class I areas. In addition to the traditional Title V, New Source Performance Standards, Maximum Achievable Control Technology and new source review permitting programs for stationary sources, Colorado also has Statewide emission control requirements for oil and gas sources, open burning, wildland fire, smoke management, automobile emissions for Front Range communities, and residential woodburning, as well as PM10 nonattainment/maintenance area requirements, dust suppression for construction areas and unpaved roads and renewable energy requirements.

Colorado adopted legislation to address renewable energy by establishing long-term energy production goals. This program is expected to reduce future expected and real emissions from coal-fired power plants. This renewable energy measure was considered a key feature of the Grand Canyon Visibility Transport Commission's recommendations. Although the Colorado renewable energy program was not specifically adopted to meet regional haze requirements, emissions from fossil-fuel fired electricity generation are avoided in the future.

Colorado is also setting emission limits (as part of this plan) for those sources subject to Best Available Retrofit Technology (BART) requirements of Phase 2 of the visibility regulations for Regional Haze (described in detail in Chapter 6 of this plan). To comply with these BART limits sources subject to BART are required to install

and operate BART as expeditiously as practicable, but not later than 5 years after EPA's approval of the implementation plan revision.

As such, this Plan documents those programs, regulations, processes and controls deemed appropriate as measures to reduce regional haze and protect good visibility in the State toward meeting the 2018 and 2064 goals established in EPA regulations and the CAA.

1.5 Reasonable Progress Towards the 2064 Visibility Goals

As described in detail in Chapters 8 and 9 of this plan, reasonable progress goals for each Class I area have been established. The Division has worked with the Western Regional Air Partnership (WRAP) and with the WRAP's ongoing modeling program to establish and refine Reasonable Progress Goals (RPGs) for Colorado Class I Areas.

Technical analyses described in this Plan demonstrate emissions both inside and outside of Colorado have an appreciable impact on the State's Class I areas. Emission controls from many sources outside Colorado are reflected in emission inventory and modeling scenarios for future cases as detailed in the WRAP 2018 PRP18b control case. Progress toward the 2064 goal is determined based on emission control scenarios described in the WRAP inventory documentation plus the state's BART and reasonable progress determinations.

Chapter 2 Plan Development and Consultation

This chapter discusses the process Colorado participated in to address consultation requirements with the federal land managers, tribes and other states in the Western Regional Air Partnership (WRAP) during the development of this Plan and future commitments for consultation.

Colorado has been a participating member of the WRAP since its inception. The WRAP completed a long-term strategic plan in 2003.[1] The Strategic Plan provides the overall schedule and objectives of the annual work plans and may be revised as appropriate. Among other things, the Strategic Plan (1) identifies major products and milestones; (2) serves as an instrument of coordination; (3) provides the direction and transparency needed to foster stakeholder participation and consensus-based decision making, which are key features of the WRAP process; and (4) provides guidance to the individual plans of WRAP forums and committees.

Much of the WRAP's effort is focused on regional technical analysis serving as the basis for developing strategies to meet the RHR requirement to demonstrate reasonable progress towards natural visibility conditions in Class I national parks and wilderness areas. This includes the compilation of emission inventories, air quality modeling, and ambient monitoring and data analysis. The WRAP is committed to using the most recent and scientifically acceptable data and methods. The WRAP does not sponsor basic research, but WRAP committees and forums interact with the research community to refine and incorporate the best available tools and information pertaining to western haze.

2.1 Consultation with Federal Land Managers (FLM)

Section 51.308(i) requires coordination between states and the Federal Land Managers (FLMs). Colorado has provided agency contacts to the Federal Land Managers as required. In development of this Plan, the Federal Land Managers were consulted in accordance with the provisions of 51.308(i)(2). Specifically, the rule requires the State to provide the Federal Land Manager with an opportunity for consultation, in person, and at least 60 days prior to holding any public hearing on an implementation plan or plan revision for regional haze. This consultation must include the opportunity for the affected Federal Land Managers to discuss their assessment of impairment of visibility in any mandatory Class I Federal area and recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment. The State must include a description of how it addressed any comments provided by the Federal Land Managers. Finally, the plan or revision must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required including development and review of implementation plan revisions and 5-year progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas.

[1] See http://www.wrapair.org/forums/sp/docs.html

Colorado participated in the WRAP to develop many elements of the SIP. The WRAP represents a conglomeration of stakeholder representing FLMs, industry, States, Tribes environmental groups and the general public. Through participation in this process, a significant portion of the consultation process with FLMs and other states has been met. In the WRAP process these stakeholders participated in various forums to help develop a coordinated emissions inventory and analysis of the impacts sources have on regional haze in the west. Coordination and evaluation of monitoring data and modeling processes were also overseen by WRAP participants. Through these coordinated technical evaluations, a regional haze-oriented evaluation of Colorado's Class I areas was constructed. Summaries of this information are available in the technical support documents of this Plan.

Public meetings were held at the Colorado Air Quality Control Commission in 2007 and 2008 to provide a comprehensive review of the technical basis for the Plan. Following these meetings, additional meetings were held with the FLMs directly concerning each of the affected Class I areas and the development of the SIP. Prior to the requests for a public hearing on the Regional Haze SIP in August and September 2010, the Division again met with the FLMs to review additions, corrections and changes to the SIP made to address both FLM concerns over the analysis of additional controls on sources not subject to BART and the completion of BART analyses occurring after the 2008 hearings (these new analyses and inventories are reflected later on in this SIP document).

The FLMs have provided comments to the Division regarding proposed regional haze determinations over the course of several years in 2007 and 2008, and again in 2010. The state has carefully considered these comments and has made changes to many of its proposed determinations based in part on these comments. For example, the state has deleted its regulatory prohibition on consideration of post-combustion controls as part of the BART analysis. The state also revisited its earlier BART determinations that relied in some respects on EPA's so called 'presumptive' emission limits for NOx and SO2, and in turn conducted robust facility-specific 5 and 4 factor analyses under BART and RP.

Most recently, the FLMs formally commented on the revised, proposed BART and RP determinations, as well as reasonable progress goals, in November and December 2010. The National Park Service, the Fish and Wildlife Service and the U.S. Forest Service provided support for the modeling approach used by the state in the BART determinations, complimented the state on thorough 5 and 4 factor analyses, clear criteria, area source evaluations, and comprehensive/improved BART and RP determinations, and presented recommendations for cost/emission limit re-evaluations. The state appreciates the supportive input from the FLMs, especially in the areas of modeling and the establishment of the RPGs. The state gave serious consideration to the recent recommendations for revising cost estimates and lowering emission limits, but the comments ultimately did not alter the state's conclusions and resulting proposals.

Regarding the costs of control, the FLMs provided numerous recommendations for revising BART and RP control costs. The state notes that there is no regulatory approach for determining costs of controls. The state considered the relevant factors for BART and RP determinations as set forth in the statute, the regulations and guidance, and consistent with the discretion expressly afforded to states under the statute and regulations. The state received detailed source-specific information for the facilities evaluated, checked this information using many different resources, and made adjustments/normalization when appropriate. The state employed engineering judgment and discretion when preparing BART and RP determinations, and found that the relevant present day and estimated future costs generally fell within the range of typical control costs nationwide. The state considered broader cost survey information to be relevant, and considered such information but did not find it dispositive; the state was informed more on facility-specific information as provided to the state to support its analyses and determinations. For most facilities even if different cost assumptions were employed or were re-assessed, expected visibility from the relevant control did not satisfy the state's guidance criteria for visibility improvement, and thus would not change the state's determination. Further, the state finds metrics like dollar per kilowatt hours or dollar per deciview of improvement of limited utility in considering the 5 or 4 factors, and opted to use its own more straightforward approach to balance and weigh costs of control and related visibility improvement. The costs used by the state were determined to be appropriate and reasonable, were balanced with the state's consideration of related visibility improvement, and further revisions based on FLM comments were not incorporated. The resulting emissions reductions from the state's BART and RP determinations for NOx and SO2 are significant and will benefit Class I Areas.

Regarding CALPUFF modeling, the FLMs provided support for the state's BART and RP modeling efforts, including the modeling protocol and methodologies. However, the state respectfully disagrees with the FLMs recommendations to cumulate visibility improvement impacts from emission controls across multiple Class I Areas. It is the state's position that the approach employed is consistent with a straightforward application of the regional haze regulation, and that the approach suggested by the FLMs, while an option that could be considered, as a general rule is not appropriate. The Commission in making its determinations on certain BART sources was aware that emissions reductions would have some level of visibility improvement in other than the most impacted Class I Area. The CALPUFF modeling output files have been and continue to be available to the FLMs or to the public to perform such analyses.

Regarding BART and RP emission limits, the FLMs provided numerous comments to the state, identifying opportunities for tightening most of the proposed limits. The state notes that there is no regulatory formula for establishing limits in the Regional Haze rule and the state applied professional judgment and utilized appropriate and delegated discretion in establishing appropriate emission limits. The stringency of the limits are tight enough to satisfy BART and RP requirements, but are not operationally unachievable. The emission limits fall within the range of limits adopted nationwide and were developed considering the requirements of the Regional Haze rule and related guidance.

Thus, between the WRAP, AQCC and individual meetings with the FLMs, the State has met the FLM consultation requirements.

Colorado commits to continued coordination and consultation with the Federal Land Managers during the development of future progress reports and Plan revisions, in accordance with the requirements of 51.308(i)(4).

2.2 Collaboration with Tribes

The Southern Ute Tribal lands in the southwest corner of Colorado are adjacent to Mesa Verde National Park, one of Colorado's Class I areas. As described above, Colorado participated in the collaborative WRAP process where Tribes were represented in all levels of the process. In addition, the Colorado Air Quality Control Commission had joint meetings with the Tribal Air Quality Council concerning regulatory and other processes related to air quality control and planning. The Southern Ute Tribe has numerous major and minor sources operating on their lands. Major source permitting is coordinated through a joint agreement with EPA Region IX. Minor sources on Tribal lands in Colorado are subject to the jurisdiction of the Tribes and this Plan contains no regulatory provisions for sources on Southern Ute lands in Colorado. The Tribes have the opportunity to develop Tribal Implementation Plans to address sources of pollution impacting visibility in their area.

2.3 Consultation with Other States

Pursuant to 40 CFR Section 51.308(d)(iv), Colorado consulted with other states during ongoing participation in the Regional Planning Organization, the Western Regional Air Partnership (WRAP), in developing the SIP. The WRAP is a collaborative effort of tribal governments, state governments and various federal agencies to implement the Grand Canyon Visibility Transport Commission's recommendations and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. EPA's regional haze regulations. The WRAP is administered jointly by the Western Governors' Association and the National Tribal Environmental Council. WRAP activities are conducted by a network of committees and forums composed of WRAP members and stakeholders who represent a wide range of viewpoints. The WRAP recognizes that residents have the most to gain from improved visibility and that many solutions are best implemented at the local, state, tribal or regional level with public participation. Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming have agreed to work together to address regional haze in the western United States. Colorado held specific discussions with states that have a primary impact on Colorado Class I areas. These include California, Utah, New Mexico and Arizona regarding the impacts from sources in these states on Colorado Class I areas.

The major amount of state consultation in the development of SIPs was through the Implementation Work Group (IWG) of the WRAP. Colorado participated in the IWG which took the products of the WRAP technical analysis and consultation process discussed above and developed a process for establishing reasonable progress goals in the western Class I areas. A description of that process is discussed in Chapter 8 -- Reasonable Progress Section of the State SIP.

Through the WRAP consultation process Colorado has reviewed and analyzed contributions from other states that reasonably may cause or contribute to visibility impairment in Colorado's Class I areas. While emissions from sources outside of Colorado have resulted in a slower rate of improvement in visibility than the rate that would be needed to attain natural conditions by 2064, most of these emissions are beyond the control of any state in the regional planning area of the WRAP. The emission sources include: emissions from outside the WRAP domain; emissions from Canada and Mexico; emissions from wildfires and windblown dust; and emissions from offshore shipping. Colorado anticipates that the long-term strategies when adopted by other states in their SIPs and approved by EPA will include emission reductions from a variety of sources that will reduce visibility impairment in Colorado's Class I areas.

Colorado's analysis of interstate impacts from specific nearby sources indicated the need for specific consultation with Nebraska, Wyoming, Utah, New Mexico and Arizona and California. In Nebraska the Gerald Gentleman Power Plant was analyzed for BART as part of the Nebraska RH process. Colorado commented to the State of Nebraska on this BART determination since emissions from this plant were indicated to impact Rocky Mountain National Park. Colorado similarly communicated with the State of Wyoming concerning BART determinations for its sources since impacts from Wyoming power plants were indicated to impact the Mt. Zirkel Wilderness Area. Colorado participated in the Four Corners Task force with Utah, New Mexico and Arizona and Tribal representatives to identify sources in the region adversely affecting air quality in the region. One element of that process was to consider sources impacting Mesa Verde or other Colorado Class I areas specifically for regional haze purposes. Through this process these States were made aware of Colorado's concerns about emissions from the Four Corners Power Plant, as it significantly impacts Mesa Verde. EPA Region IX was notified of Colorado's concerns with this facility since they are responsible for issuing and overseeing permits on this facility. Finally, California was contacted to discuss NOx emissions impacting Colorado Class I areas. California identified measures being taken in the State to reduce NOx emissions from mobile and other sources. Additional details concerning the Four Corners Task Force can be found in Section 9.5.5.3 of this Regional Haze SIP.

During the 2010 public hearing process, Colorado provided notification to the WRAP-member states and to other nearby states that a Regional Haze SIP revision had been prepared and invited review and comment on the plan and supporting documents.

By participating in the WRAP and the Four Corner's Task Force, and through specific comments and communications with the participating states, Colorado has satisfied the state consultation requirement.

2.4 General Consultation

As part of the regional haze SIP development process Colorado will continue to coordinate and consult with parties as summarized in the long-term strategy described in Chapter 9.

Chapter 3 Monitoring Strategy

Federal regulations in 40 CFR 51.305 and 51.308(d)(4) require states to have a monitoring strategy in the SIP sufficient to characterize reasonable progress at each of the Class I areas, specifically Phase 1: reasonably attributable visibility impairment (RAVI) and Phase 2: regional haze visibility impairment in federal Class I areas within the state. Because Colorado adopted a visibility SIP to address the Phase 1 requirements (51.305), a monitoring strategy is currently in place through an approved SIP. The State of Colorado utilizes data from the IMPROVE monitoring system which is designed to provide a representative measure of visibility in each of Colorado's Class I areas.

3.1 RAVI Monitoring Strategy in Current Colorado LTS

States are required by EPA to have a monitoring strategy for evaluating visibility in any Class I area by visual observation or other appropriate monitoring techniques. The monitoring strategy in the RAVI LTS is based on meeting the following four goals:

1. To provide information for new source visibility impact analysis.
2. To determine existing conditions in Class I areas and the source(s) of any certified impairment.
3. To determine actual affects from the operation of new sources or modifications to major sources on nearby Class I areas.
4. To establish visibility trends in Class I areas to evaluate progress towards meeting the national visibility goal.

Potential new major source operators must conduct visibility analyses utilizing existing visibility data. If data are adequate and/or representative of the potentially impacted Class I area(s), the permit holder will be notified of the visibility levels against which impacts are to be assessed. If visibility data are not adequate, pre-construction monitoring of visibility may be required.

If the Federal Land Managers (FLMs) or the State of Colorado certifies existing impairment in a Class I area, the Division will determine if emissions from a local source(s) operator(s) can be reasonably attributed to cause or contribute to the documented visibility impairment. In making this determination the Division will consider all available data including the following:

1. Data supplied by the FLM;
2. The number and type of sources likely to impact visibility in the Class I area;
3. The existing emissions and control measures on the source(s);
4. The prevailing meteorology near the Class I area; and
5. Any modeling that may have been done for other air quality programs.

If available information is insufficient to make a decision regarding "reasonable attribution" of visibility impairment from an existing source(s) the State will initiate cooperative studies to help make such a determination. Such studies could involve the FLMs, the potentially affected source(s), the EPA, and others.

The monitoring strategy also included a commitment from the State to sponsor or share in the operation of visibility monitoring stations with FLMs as the need arises and resources allow.

The State commits to periodically compile information about visibility monitoring conducted by various entities throughout the State and assembling and evaluating visibility data.

Colorado law (C.R.S. 25-7-212(3)(a)) requires the federal land management agencies of Class I areas in Colorado (i.e., U.S.D.I. National Park Service and U.S.D.A. Forest Service) to “develop a plan for evaluating visibility in that area by visual observation or other appropriate monitoring technique approved by the federal environmental protection agency and shall submit such plan for approval by the division for incorporation by the commission as part of the state implementation plan.” The agencies indicated they developed, adopted, and implemented a monitoring plan through the Class I visibility monitoring collaborative known as IMPROVE. EPA’s Regional Haze Rule (40 CFR 51.308(d)(4)) indicates, “The State must submit with the Implementation Plan a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment representative of all mandatory Class I Federal areas within the State….Compliance with this requirement may be met through participating in the Interagency Monitoring of Protected Visual Environments [IMPROVE] network.” The federal agencies’ monitoring plan relies on this network and ensures each Class I area in Colorado will have a monitor representative of visibility in the Class I area. In the LTS revision, submitted to EPA in 2008, the Division provided letters from the federal land managers and approval letters from the Division indicating this requirement was being met.

3.2 Regional Haze Visibility Impairment Monitoring Strategy

Under 40 CFR 51.308(d), a State must develop a monitoring strategy in the RH SIP to measure, characterize, and report regional haze visibility impairment representative of all federal Class I areas within the State. This monitoring strategy must be coordinated with the monitoring strategy described in Section 3.1 above, and will be met by participating in the IMPROVE network.

Colorado’s monitoring strategy is to participate in the IMPROVE monitoring network. To insure coordination with the RAVI monitoring strategy, it includes the same four goals as in the RAVI LTS plus an additional goal:

> To provide regional haze monitoring representing all visibility-protected federal Class I areas

3.3 Associated Monitoring Strategy Requirements

Other associated monitoring strategy requirements in 40 CFR 51.308(d)(4) and Colorado's associated SIP commitment are enumerated below:

1. Establishment of any additional monitoring sites or equipment to evaluate achievement of reasonable progress goals [40 CFR 51.308(d)(4)(i)].
   a. Colorado will work collaboratively with IMPROVE, EPA, the Federal Land Managers and other potential sponsors to ensure that representative monitoring continues for all of its Class I areas. If necessary, additional monitoring sites or equipment will be established to evaluate the achievement of reasonable progress goals.
   b. If funding for a site(s) is eliminated by EPA, the Division will consult with FLMs and IMPROVE to determine the best remaining site to use to represent the orphaned Class I areas.
2. Procedures describing how monitoring data and other information are used in determining the State's contribution of emissions to visibility impairment in any federal Class I area [40 CFR 51.308(d)(4)(ii)].
   a. Colorado has participated extensively in the WRAP. One of the Regional Modeling Center (RMC) tools is the PSAT (PM Source Apportionment Technology) that relates emission sources to relative impacts at Class I areas. Details about PSAT are contained in the Technical Support Documents for each Class I area. Colorado will utilize the PSAT method and other models as needed and recommended by EPA modeling guidance for visibility evaluations, or other tools, to assist in determining the State's emission contribution to visibility impairment in any federal Class I area. As part of this process the State commits to consult with the EPA and FLMs or other entities as deemed appropriate when using monitoring and other data to determine the State's contribution of emissions to impairment in any Class I area.
   b. Colorado will continue to review monitoring data from the IMPROVE sites and examine the chemical composition of individual specie concentrations and trends, to help understand the relative contribution of emissions from upwind states on Colorado Class I areas and any contributions from Colorado to downwind Class I areas in other states. This will occur no less than every five years in association with periodic SIP, LTS and monitoring strategy progress reports and reviews.
3. Provisions for annually reporting visibility monitoring data to EPA [40 CFR 51.308(d)(4)(iv)].
   a. IMPROVE data are centrally compiled and made available to EPA, states and the public via various electronic formats and websites including IMPROVE (http://vista.cira.colostate.edu/improve/) and VIEWS (http://vista.cira.colostate.edu/views/)Through participation in the IMPROVE network, Colorado will partially satisfies the requirement to annually report to EPA visibility data for each of Colorado's Class I areas.

b. An annual compilation of the Colorado data will be prepared and reported to the EPA electronically.

4. A statewide emissions inventory of pollutants reasonably expected to cause or contribute to visibility impairment for a baseline year, most recent year data is available, and future projected year [40 CFR 51.308(d)(4)(v)].

   a. Section 5.4 of this Plan includes a summary of Colorado statewide emissions by pollutant and source category. The inventory includes air pollution sources that can reasonably be expected to cause or contribute to visibility impairment to federal Class I areas.

      i. The WRAP-developed Plan02d (March 2008) inventory is both the baseline and most recent year of data available for a statewide inventory. It is an inventory intended to represent typical annual emissions during the baseline period, 2000-2004. From the baseline/current inventory, projections were made to 2018. The WRAP's 2018 Base Case or PRP18b inventory was utilized for final model projections. This represented the most recent BART determinations reported by the States and EPA offices, projection of future fossil-fuel electric generation plants, revised control strategy rulemaking and updated permit limits for point and area sources in the WRAP region as of Spring 2009 (http://www.wrapedms.org/InventoryDesc.aspx). The emission inventory information was collaboratively developed between Division staff and the WRAP. A summarized western state and boundary condition inventory is available at: http://vista.cira.colostate.edu/TSS/Results/emis_smry_p02c_b18b_a5.xls

5. Commitment to update the emissions inventory [40 CFR 51.308(d)(4)(v)].

   a. Colorado will update its portion of the regional inventory, on the tri-annual cycle as dictated by the Air Emissions Reporting Rule (AERR) (see section 3.5) in order to track emission change commitments and trends as well as for input to regional modeling exercises.

6. Any additional reporting, recordkeeping, and measures necessary to evaluate and report on visibility [40 CFR 51.308(d)(4)(vi)].

   a. Colorado will provide any additional reporting, recordkeeping and measures necessary to evaluate and report on visibility but is unaware of the need for any specific commitment at this time beyond those made in this section and in the LTS section.

3.4 Overview of the IMPROVE Monitoring Network

In the mid-1980's, the IMPROVE program was established to measure visibility impairment in mandatory Class I Federal areas throughout the United States. The monitoring sites are operated and maintained through a formal cooperative relationship between the EPA, National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management, and U.S. Forest Service. In 1991, several additional organizations joined the effort: State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials, Western States Air Resources

Council, Mid-Atlantic Regional Air Management Association, and Northeast States for Coordinated Air Use Management.

The objectives of the IMPROVE program include establishing the current visibility and aerosol conditions in mandatory Class I federal areas; identifying the chemical species and emission sources responsible for existing human-made visibility impairment; documenting long-term trends for assessing progress towards the national visibility goals; and support the requirements of the federal visibility rules by providing regional haze monitoring representing all visibility-protected federal Class I areas where practical.

The data collected at the IMPROVE monitoring sites are used by land managers, industry planners, scientists, consultants, public interest groups, and air quality regulators to better understand and protect the visual air quality resource in Class I areas. Most importantly, the IMPROVE Program scientifically documents for American citizens, the visual air quality of their wilderness areas and national parks.

In Colorado, there are six IMPROVE monitors that are listed under the site name in Figure 3-1. As shown, some monitors serve multiple Class I areas. For example, the monitor with site name Mount Zirkel is located just south of the Mount Zirkel Wilderness Area (on Buffalo Pass) but this monitor is also designated to represent the Rawah Wilderness Area.

Figure 3-1 Colorado Class I Areas and IMPROVE Monitor Locations

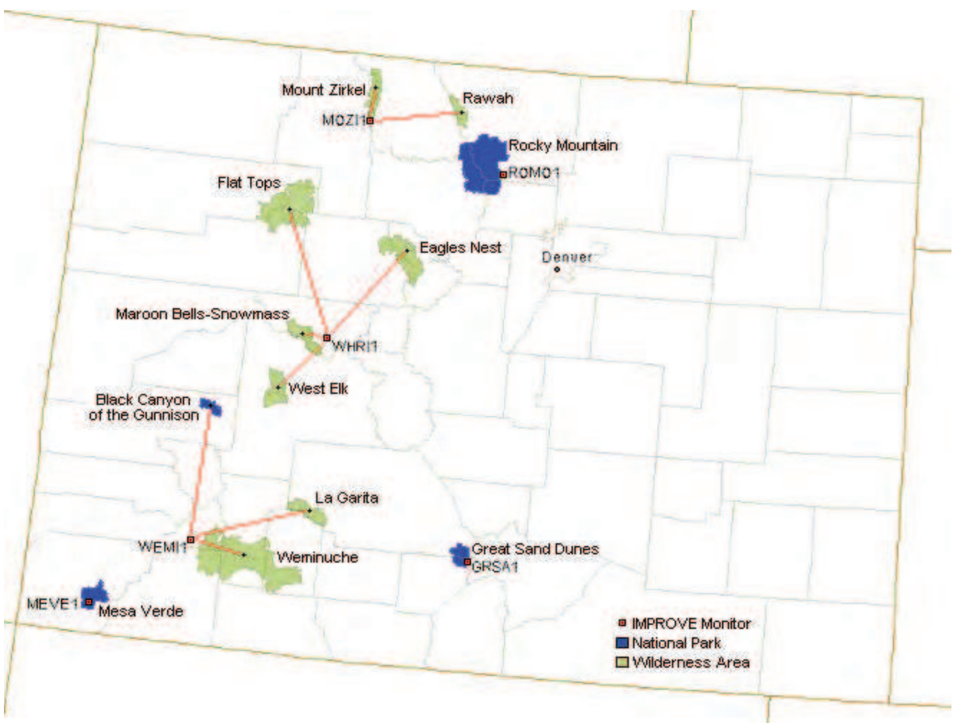


Figure 3-2 includes summary information for each IMPROVE monitor. The National Park Service (NPS) and the U.S. Forest Service (USFS) each operate and maintain three IMPROVE monitors in the State.

Figure 3-2 Colorado IMPROVE Monitoring Site Information

Mandatory Class I Federal Area	Operating Agency	IMPROVE Monitor	Elevation [ft]	Start Date
Great Sand Dunes National Park	NPS	GRSA1	8,215	5/4/1988
Mesa Verde National Park	NPS	MEVE1	7,142	3/5/1988
Mount Zirkel Wilderness	USFS	MOZI1	10,640	7/30/1994
Rawah Wilderness				
Rocky Mountain National Park	NPS	ROMO1	9,039	9/19/1990
Weminuche Wilderness	USFS	WEMI1	9,072	3/2/1988
Black Canyon of Gunnison NP				
La Garita Wilderness				
Eagles Nest Wilderness	USFS	WHRI1	11,214	7/17/2000
Flat Tops Wilderness				
Maroon Bells-Snowmass Wilderness				
West Elk Wilderness				

3.5 Commitment for Future Monitoring

The State commits to continue utilizing the IMPROVE monitoring data and emission data to track reasonable progress. The State commits to providing summary visibility data in electronic format to the EPA on an annual basis from the IMPROVE monitoring, or other relevant sites. Also, the State commits to continue developing updated emission inventories on a tri-annual basis as required under the Air Emissions Reporting Rule sufficient to allow for the tracking of emission increases or decreases attributable to adopted strategies or other factors such as growth, economic downturn, or voluntary or permit related issues. These monitoring and emissions data will be available for electronic processing in future modeling or other emission tracking processes. Information collected from the monitoring system and emission inventory work will be made available to the public.

Colorado will depend on the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring program[2] to collect and report aerosol monitoring data for reasonable progress tracking as specified in the Regional Haze Rule (RHR). Because the RHR is a long-term tracking program with an implementation period nominally set for 60 years, the state expects the configuration of the monitors, sampling site locations, laboratory analysis methods and data quality assurance, and network operation protocols will not change, or if changed, will remain directly comparable to those operated by the IMPROVE program during the 2000-04 RHR baseline period. Technical analyses and reasonable progress goals in RHR plans are based on data from these sites. The state must be notified and agree to any changes in the IMPROVE program affecting the RHR tracking sites, before changes are made. Further, the state notes resources to operate a complete and representative monitoring network of these long-term reasonable progress tracking sites is currently the responsibility of the Federal government. Colorado is satisfying the monitoring requirements by participating in the IMPROVE network. Colorado will continue to work with EPA in refining monitoring

[2] http://vista.cira.colostate.edu/improve/

strategies as new technologies become available in the future. If resource allocations change in supporting the monitoring network the state will work with the EPA and FLMs to address future monitoring requirements.

Colorado depends on IMPROVE program-operated monitors at six sites as identified in Figures 3.1 and 3.2 for tracking RHR reasonable progress. Colorado will depend on the routine timely reporting of monitoring data by the IMPROVE program for the reasonable progress tracking sites. Colorado commits to provide a yearly electronic report to the EPA of representative visibility data from the Colorado sites based on data availability from this network.

As required under 40 CFR 51.308(d)(4)(v) the State of Colorado has prepared a statewide inventory of emissions reasonably expected to cause or contribute to visibility impairment in Federal Class I Areas. Section 5.4 of this Plan summarizes the emissions by pollutant and source category.

The State of Colorado commits to updating statewide emissions on a tri-annual basis as required under the December 17, 2008 Air Emissions Reporting Rule (AERR). The updates will be used for state tracking of emission changes, trends, and input into any regional evaluation of whether reasonable progress goals are being achieved. Should no regional coordinating/planning agency exist in the future, Colorado commits to continue providing required emission updates as specified in the AERR and 40 CFR 51.308(d)(4)(v).

The State will use the Fire Emissions Tracking System (FETS)[3] to store and access fire emissions data. Should this system become unavailable Colorado will work with the FLMs and the EPA to establish a process to track and report fire emissions data if continued use of such information is deemed necessary. The State will also depend upon periodic collective emissions inventory efforts by other states meeting emission reporting requirements of the AERR to provide a regional inventory for future modeling and evaluations of regional haze impacts. Colorado recognizes that other inventories of a nature more sophisticated than available from the AERR may be required for future regional haze or other visibility modeling applications. In the past, such inventories were developed through joint efforts of states with the WRAP, and it is currently beyond available resources to provide an expanded regional haze modeling quality inventory if one is needed for future evaluations. The State will continue to depend on and use the capabilities of the WRAP-sponsored Regional Modeling Center (RMC)[4] or other similar joint modeling efforts to simulate the air quality impacts of emissions for haze planning purposes. The State notes the resources to ensure data preparation, storage, and analysis by the state and regional coordinating agencies such as the WRAP will require adequate ongoing resources. Colorado commits to work with other states, tribes, the FLMs and the EPA to help ensure future multi-state modeling, monitoring or inventory processes can be met but makes no commitment in this SIP to fund such processes. Colorado will track data related to RHR haze plan implementation for sources for which the state has regulatory authority.

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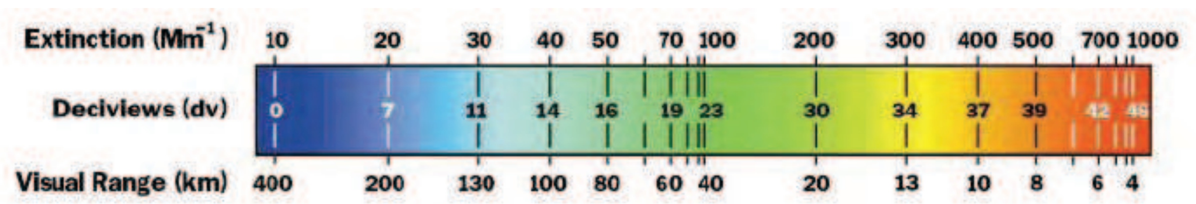
[3] http://www.wrapfets.org/
[4] http://pah.cert.ucr.edu/aqm/308/

Chapter 4 Baseline and Natural Visibility Conditions in Colorado, and Uniform Progress for Each Class I Area

4.1 The Deciview

Each IMPROVE monitor collects particulate concentration data which are converted into reconstructed light extinction through a complex calculation using the IMPROVE equation (see Technical Support Documents for any Class I area). Reconstructed light extinction (denoted as b_{ext}) is expressed in units of inverse megameters (1/Mm or Mm^{-1}). The Regional Haze Rule requires the tracking of visibility conditions in terms of the Haze Index (HI) metric expressed in ***the deciview (dv)*** unit [(40 CFR 51.308(d)(2)]. Generally, a one deciview change in the haze index is likely humanly perceptible under ideal conditions regardless of background visibility conditions.

The relationship between extinction (Mm^{-1}), haze index (dv) and visual range (km) are indicated by the following scale:



4.2 Baseline and Current Visibility Conditions

EPA requires the calculation of baseline conditions [(40 CFR 51.308(d)(2)(i) and (ii)]. The baseline condition for each Colorado Class I area is defined as the five year average (annual values for 2000 - 2004) of IMPROVE monitoring data (expressed in deciviews) for the most-impaired (20% worst) days and the least-impaired (20% best) days. For this first regional haze SIP submittal, the baseline conditions are the reference point against which visibility improvement is tracked. For subsequent RH SIP updates (in the year 2018 and every 10 years thereafter), baseline conditions are used to calculate progress from the beginning of the regional haze program.

Current conditions for the best and worst days are calculated from a multiyear average, based on the most recent 5-years of monitored data available [40 CFR 51.308(f)(1)]. This value will be revised at the time of each periodic SIP revision, and will be used to illustrate: (1) The amount of progress made since the last SIP revision, and (2) the amount of progress made from the baseline period of the program.

Colorado has established baseline visibility for the cleanest and worst visibility days for each Class I area based on, on-site data from the IMPROVE monitoring sites. A five-year average (2000 to 2004) was calculated for each value (both best and worst). The calculations were made in accordance with 40 CFR 51.308(d)(2) and EPA's *Guidance for Tracking Progress Under the Regional Haze Rule* (EPA-454/B-03-004, September 2003). The IMPROVE II algorithm as described in the TSDs has been utilized for the calculation of Uniform Rate of Progress glide slopes for all Class I areas. Figure 4-4 contains the baseline conditions for each IMPROVE monitor site in Colorado.

4.3 Monitoring Data

Visibility-impairing pollutants both reflect and absorb light in the atmosphere, thereby affecting the clarity of objects viewed at a distance by the human eye. Each haze pollutant has a different light extinction capability. In addition, relative humidity changes the effective light extinction of both nitrates and sulfates. Since haze pollutants can be present in varying amounts at different locations throughout the year, aerosol measurements of each visibility-impairing pollutant are made every three days at the IMPROVE monitors located in or near each Class I area.

In addition to extinction, the Regional Haze Rule requires another metric for analyzing visibility impairment, known as the "Haze Index", which is based on the smallest unit of uniform visibility change that can be perceived by the human eye. The unit of measure is the deciview (denoted dv).

More detailed information on the methodology for reconstructing light extinction along with converting between the haze index and reconstructed light extinction can be found in the Technical Support Documents for any of Colorado's twelve Class I areas.

The haze pollutants reported by the IMPROVE monitoring program are sulfates, nitrates, organic carbon, elemental carbon, fine soil and coarse mass. Summary data in Figures 4-1 and 4-2 are provided below for the worst and best days from the 6 IMPROVE monitors for the 6 haze pollutants.

Figure 4-1 Reconstructed Aerosol Components for 20% Worst Days (2000-2004)

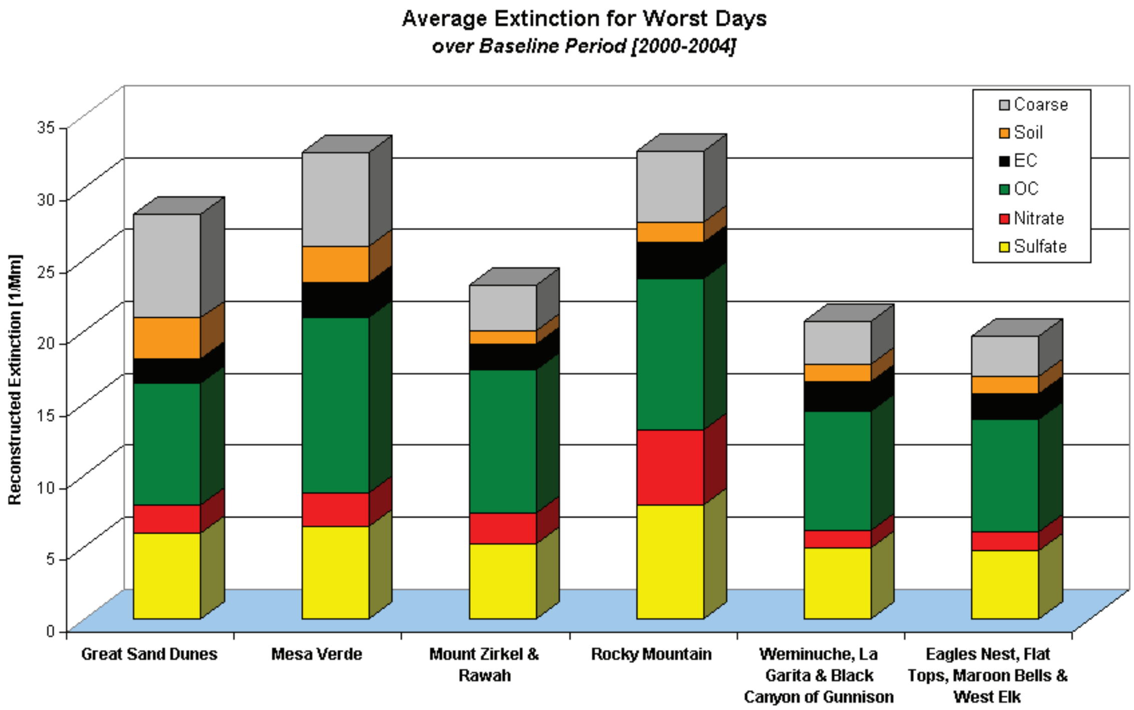
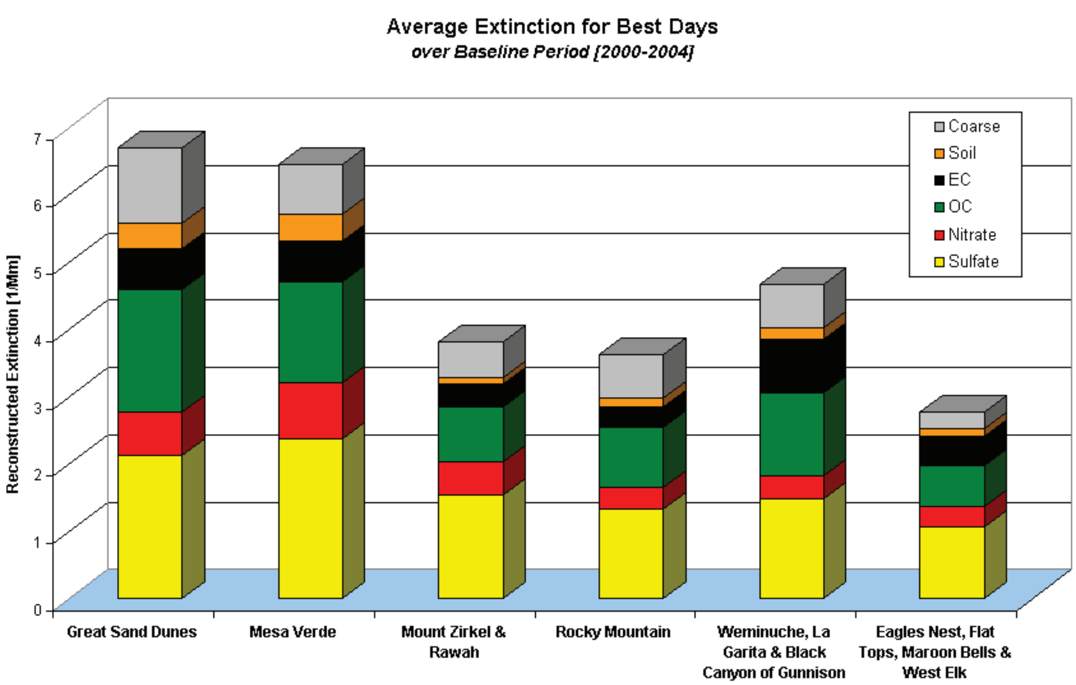


Figure 4-2 Reconstructed Aerosol Components for 20% Best Days (2000-2004)



More detailed information on reconstructed extinction for each Class I area can be found in the Technical Support Document.

4.4 Natural Visibility Conditions

The natural condition for each Class I area represents the visibility goal expressed in deciviews for the most-impaired (20% worst) days and the least-impaired (20% best) days that would exist if there were only naturally occurring impairment. Natural visibility conditions must be calculated by estimating the degree of visibility impairment existing under natural conditions for the most impaired and least impaired days, based on available monitoring information and appropriate data analysis techniques. [(40 CFR 51.308(d)(iii)].

Figure 4-3, lists the 2064 natural conditions goal in deciviews for each Colorado Class I area. The natural conditions estimates were calculated consistent with EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA-454/B-03-005, September 2003). The natural conditions goal can be adjusted as new visibility information becomes available. The Natural Haze Level II Committee methodology was utilized as described in the TSD.

Figure 4-3: 2064 Natural Conditions Goal for Worst Days

Mandatory Class I Federal Areas in Colorado	2064 Natural Conditions for 20% Worst Days [Deciview]
Great Sand Dunes National Park & Preserve	6.66
Mesa Verde National Park	6.81
Mount Zirkel & Rawah Wilderness Areas	6.08
Rocky Mountain National Park	7.15
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	6.21
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	6.06

4.5 Uniform Progress

For the worst days, uniform progress for each Colorado Class I area is the calculation of a uniform rate of progress per year to achieve natural conditions in 60 years [(40 CFR 51.308(d)(1)(i)(B)]. In this initial SIP submittal, the first benchmark is the 2018 deciview level based on the uniform rate of progress applied to the first fourteen years of the program. This is also shown in Figure 4-4 in the column "2018 Uniform Progress Goal (Deciview)".

For the 20% worst days, the uniform rate of progress (URP) in deciviews per year (i.e. slope of the glide path) is determined by the following equation:

URP = [Baseline Condition - Natural Condition] / 60 years

By multiplying the URP by the number of years in the 1st planning period one can calculate the uniform progress needed by 2018 to be on the path to achieving natural visibility conditions by 2064:

2018 UPG = [URP] x [14 years]

The 14 years comprising the 1st planning period includes the 4 years between the end of the baseline period and the SIP submittal date plus the standard 10-year planning period for subsequent SIP revisions.

More detailed information on the worst days along with the calculations and glide slope associated with each CIA can be found in Section 3 of the Technical Support Documents for any of Colorado's twelve Class I areas. This calculation is consistent with EPA's *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Rule* (June 1, 2007).

For the best days at each Class I area, the State must ensure no degradation in visibility for the least-impaired (20% best) days over the same period. More detailed information on the best days, along with the determination of the best day's baseline for a particular CIA, can be found in Section 3 of the Technical Support Document.

Figure 4-4 provides the 2018 uniform rate of progress chart for the worst days and the baseline that must not be exceeded over the years in order to maintain the best days. As with natural conditions, uniform rate of progress can be adjusted as new visibility information becomes available.

Figure 4-4: Uniform Rate of Progress for Each Colorado Class I Area

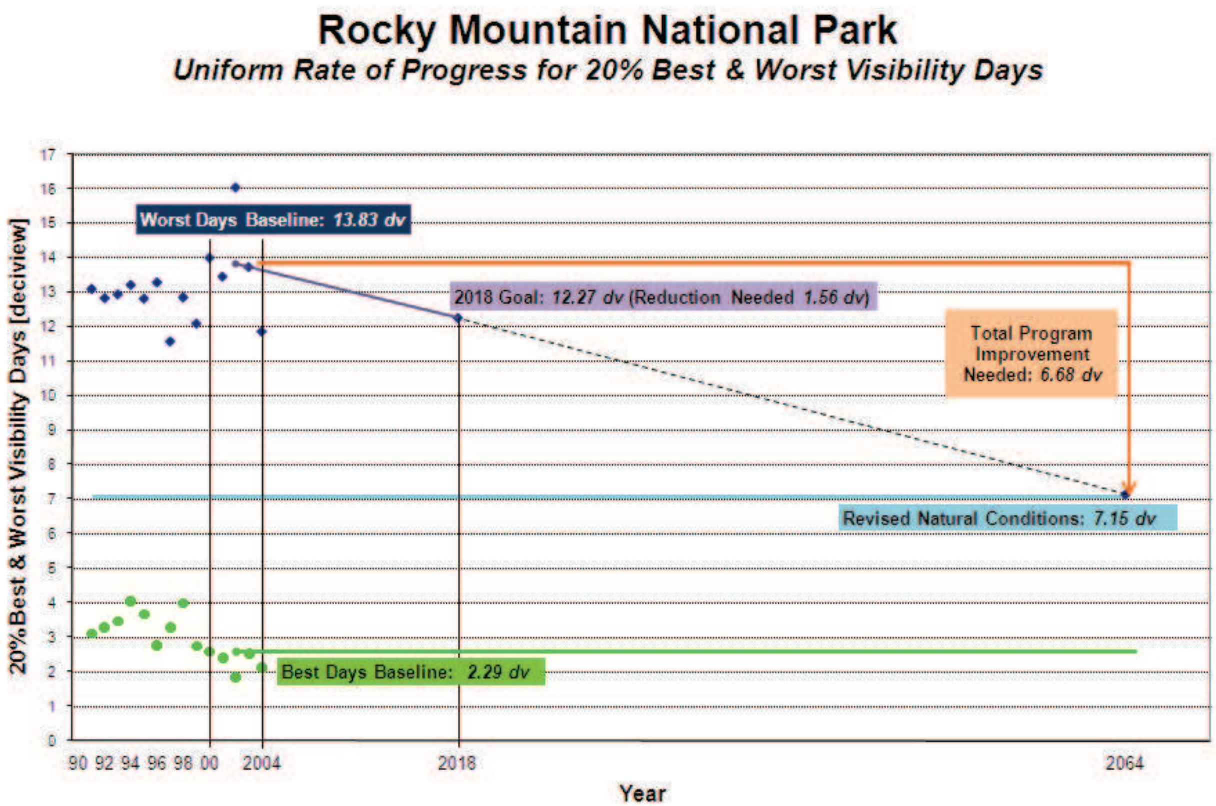
Baseline Summary of Best & Worst Days in Haze Index Metric

Baseline Period (2000-2004)

	20% Worst Days					20% Best Days
Mandatory Class I Federal Area	Baseline Condition [Deciview]	2018 Uniform Progress Goal [Deciview]	2018 Goal Delta [Deciview]	2064 Natural Conditions [deciview]	2064 Delta (Baseline - 2064 NC) [deciview]	Best Days Baseline Condition [Deciview]
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	6.66	6.12	4.50
Mesa Verde National Park	13.03	11.58	1.45	6.81	6.22	4.32
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	6.08	4.44	1.61
Rocky Mountain National Park	13.83	12.27	1.56	7.15	6.68	2.29
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	6.21	4.12	3.11
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	6.06	3.55	0.70

Figure 4-5 provides a visual example of 2018 uniform progress glide slope for the worst days and the best days baseline.

Figure 4-5: Example of Uniform Progress for 20% Best & Worst Days at Rocky Mountain National Park



Chapter 5 Sources of Impairment in Colorado

5.1 Natural Sources of Visibility Impairment

Natural sources of visibility impairment include anything not directly attributed to human-caused emissions of visibility-impairing pollutants. Natural events (e.g. windblown dust, wildfire, volcanic activity, biogenic emissions) also introduce pollutants contributing to haze in the atmosphere. Natural visibility conditions are not constant; they vary with changing natural processes throughout the year. Specific natural events can lead to high short-term concentrations of visibility-impairing particulate matter and its precursors. Natural visibility conditions, for the purpose of Colorado's regional haze program, are represented by a long-term average of conditions expected to occur in the absence of emissions normally attributed to human activities. Natural visibility conditions reflect contemporary vegetated landscape, land-use patterns, and meteorological/climatic conditions. The 2064 goal is the natural visibility conditions for the 20% worst natural conditions days.

Natural sources contribute to visibility impairment but natural emissions cannot be realistically controlled or prevented by Colorado and therefore are beyond the scope of this plan. Current methods of analysis of IMPROVE data do not provide a distinction between natural and anthropogenic emissions. Instead, for the purposes of this SIP, they are estimated as described in Section 4.4.

5.2 Anthropogenic Sources of Visibility Impairment

Anthropogenic or human-caused sources of visibility impairment include anything directly attributable to human-caused activities producing emissions of visibility-impairing pollutants. Some examples include transportation, agriculture activities, mining operations, and fuel combustion. Anthropogenic visibility conditions are not constant and vary with changing human activities throughout the year. Generally anthropogenic emissions include not only those anthropogenic emissions generated or originating within the boundaries of the United States but also international emissions transported into a state. Some examples include emissions from Mexico, Canada, and maritime shipping emissions in the Pacific Ocean.

Although anthropogenic sources contribute to visibility impairment, international emissions cannot be regulated, controlled or prevented by the states and therefore are beyond the scope of this planning document. Any reductions in international emissions would likely fall under the purview of the U.S. EPA administrator.

5.3 Overview of Emission Inventory System -TSS

The Western Regional Air Partnership (WRAP) developed the Technical Support System (TSS) as an Internet access portal to all the data and analysis associated with the development of the technical foundations of Regional Haze plans across the Western US. The TSS provides state, county, and grid cell level emissions information for typical criteria pollutants such as SO2 & NOx and other secondary particulate forming pollutants such as VOC and NH3. Eleven different emission inventories were developed comprising the following source categories: point, area, on-road mobile, off-road mobile, oil and gas, anthropogenic fire, natural fire, biogenic, road dust, fugitive dust and windblown dust. Summaries of the emissions data for sources in Colorado are contained in subsequent Figures 5-1 through 5-8 in this section. In addition the Emissions Inventory TSD in this SIP contains a more detailed accounting of sources in Colorado used in the modeling exercise.

In the WRAP process, member states and the EPA agreed the tremendous amount of data collected, analyzed and maintained by the WRAP and the Regional Modeling Center would be impracticable and nearly infeasible to include in individual TSDs for individual States. For the purposes of administrative efficiency, WRAP data and analysis upon which the member states built their Regional Haze SIPs are available through the WRAP on the TSS Web site. For a more complete description of the emission inventory and process and for access information related to the web site containing comprehensive detail about the inventory please refer to the Emissions Inventory TSD in this SIP.

5.4 Emissions in Colorado

Federal visibility regulations (40 CFR 51.308(d)(4)(v)) require a statewide emission inventory of pollutants reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The pollutants inventoried by the WRAP that Colorado used for this SIP include sulfur dioxide (SO2), nitrogen oxides (NOx), volatile organic compounds (VOC), primary organic aerosol (POA), elemental carbon (EC), fine particulate (Soil-PM2.5), coarse particulate (PM-2.5 to PM-10), and ammonia (NH3). An inventory was developed for the baseline year 2002, and projections of future emissions have been made for 2018. Colorado will provide updates to the EPA on this inventory on a three year basis as required by the AERR. Not all of the categories used for modeling purposes are contained in the AERR. A summary of the inventory results follows; the complete emission inventory is included in Section 5 of the Technical Support Document.

Emission inventories form one leg of the analysis stool to evaluate sources' impacts on visibility. Emission inventories are created for all of critical chemicals or species known to directly or indirectly impact visual air quality. These inventories become inputs to air quality models predicting concentrations of pollutants over a given space and time. For this SIP, the WRAP developed emission inventories for each state with input from participating stakeholders. A complete description of the development and content of the emission inventories can be found on the WRAP Technical Support System web site: http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx and a summary description of the inventory is found in the Emission Inventory TSD.

Dispersion modeling predicts daily atmospheric concentrations of pollutants for the baseline year and these modeled results are compared to monitored data taken from the IMPROVE network. A second inventory is created to predict emissions in 2018 based on expected controls, growth, or other factors. Additional inventories are created for future years to simulate the impact of different control strategies. The process for inventorying sources is similar for all species of interest. The number and types of sources is identified by various methods. For example, major stationary sources report actual annual emission rates to the EPA national emissions database. Colorado collects annual emission data from both major and minor sources and this information is used as input into the emissions inventory. In other cases, such as mobile sources, an EPA mobile source emissions model is used to develop emission projections. Colorado vehicle registration, vehicle mile traveled information and other vehicle data are used to tailor the mobile source data to best represent statewide and area specific emissions. Population, employment and household data are used in other parts of the emissions modeling to characterize emissions from area sources such as home heating. Thus, for each source type, emissions are calculated based on an emission rate and the amount of time the source is operating. Emission rates can be based on actual measurements from the source, or EPA emission factors based on data from tests of similar types of emission sources. In essence all sources go through the same process. The number of sources is identified, emission rates are determined by measurements of those types of sources and the time of operation is determined. By multiplying the emission rate times the hours of operation in a day, a daily emission rate can be calculated.

It is noted that certain source categories are more difficult to make current and future projections for. This is simply because market dynamics, growth factors, improvements in emission factors, types and number of sources, improvements in controls and changes in regulations make the future less predictable. Oil and gas sources in Colorado can be substantial for selected pollutants and significant efforts went into this SIP to improve emissions estimates for Colorado and other western states to help make the modeling as reflective as possible of known and future emissions. Future SIP updates will take into account any new information related to this, and other, source categories.

The following presents the Colorado emissions from the TSS, as provided to the WRAP early 2009. The “Plan 2002(d)” and “PRP 2018(b)” phrases on each of the emission inventory tables signify the version of inventories by year. A detailed explanation of each plan can be found in the Emission Inventory TSD. These inventories do not reflect the additional emission reductions that will result from the 2010 revised Best Available Retrofit Technology and reasonable progress determinations. An accounting of these emission reductions are presented in Chapter 9 of this plan.

Figure 5-1 Colorado SO2 Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide SO2 Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	97,984	44,062	-55%
Area	6,533	7,644	17%
On-Road Mobile	4,389	677	-85%
Off-Road Mobile	3,015	754	-75%
WRAP Area O&G	118	11	-91%
Road Dust	4	6	34%
Fugitive Dust	6	5	-13%
Anthro Fire	108	91	-15%
Natural Fire	3,335	3,335	0%
Biogenic	-	-	-
Total:	**115,492**	**56,585**	**-51%**

Sulfur dioxide emissions produce sulfate particles in the atmosphere. Ammonium sulfate particles have a significantly greater impact on visibility than pollutants like dust from unpaved roads due to the physical characteristics causing greater light scattering from the particles. Sulfur dioxide emissions come primarily from coal combustion at electrical generation facilities but smaller amounts come from natural gas combustion, mobile sources and even wood combustion. Other than natural fire there are no biogenic SO2 emissions of significance in Colorado. Even allowing for those fire-related sulfur dioxide emissions to be counted as 'natural' these represent only 3% of the statewide inventory. A 51% statewide reduction in SO2 emissions is expected by 2018 due to planned controls on existing point sources, even with a growth consideration for electrical generating capacity for the State. Similar reductions in the West are expected from other states as BART or other planned controls take effect by 2018. The only sulfur dioxide category expected to increase is area sources. Area sources of sulfur oxides are linked to population growth as the activity factor. As population increases in Colorado from the base case to 2018, this category is expected to increase. A typical area source for sulfur dioxide would be home heating.

Figure 5-2 Colorado NO_x Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide NOx Emissions		
	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	118,667	101,818	-14%
Area	11,729	16,360	39%
On-Road Mobile	141,883	45,249	-68%
Off-Road Mobile	62,448	37,916	-39%
WRAP Area O&G	23,518	33,517	43%
Road Dust	1	1	32%
Fugitive Dust	16	14	-13%
Anthro Fire	520	408	-21%
Natural Fire	9,377	9,377	0%
Biogenic	37,349	37,349	0%
Total:	**405,507**	**282,010**	**-30%**

Nitrogen oxides (NOx) are generated during any combustion process where nitrogen and oxygen from the atmosphere combine together under high temperature to form nitric oxide, and to a lesser degree nitrogen dioxide. Other odd oxides of nitrogen are also produced to a much smaller degree. Nitrogen oxides react in the atmosphere to form nitrate particles. Larger nitrate particles have a slightly greater impact on visibility than do sulfate particles of the same size and are much more effective at scattering light than mineral dust particles. Nitrogen oxide emissions in Colorado are expected to decline by 2018, primarily due to significant emission reductions from point, mobile and area sources. Off-road and on-road vehicles emissions will decline by more than 80,000 tons per year from the base case emissions total of 204,000 tons per year. Increases in area sources, as with sulfur dioxide, are related to population growth with an expected 4,000 tons per year increase by 2018. Again, home heating would be a typical area source of NOx with growth in emissions related to population increases. Oil and gas development by 2018 is also expected to increase statewide emissions by about 10,000 tons per year.

Figure 5-3 Colorado VOC Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide VOC Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	91,750	77,312	-16%
Area	99,191	136,032	37%
On-Road Mobile	100,860	41,489	-59%
Off-Road Mobile	38,401	24,684	-36%
WRAP Area O&G	27,259	43,639	60%
Road Dust	-	-	-
Fugitive Dust	-	-	-
Anthro Fire	915	666	-27%
Natural Fire	20,404	20,404	0%
Biogenic	804,777	804,777	0%
Total:	**1,183,557**	**1,149,002**	**-3%**

Volatile organic compounds (VOCs) are expected to decline slightly by 2018. Among other sources, volatile organic compounds from automobiles, industrial and commercial facilities, solvent use, and refueling automobiles all contribute to VOC loading in the atmosphere. Substantial natural emissions of VOCs come from vegetation. VOCs can directly impact visibility as emissions condense in the atmosphere to form an aerosol. Of more significance is the role VOCs play in the photochemical production of ozone in the troposphere. Volatile organic compounds react with nitrogen oxides to produce nitrated organic particles that impact visibility in the same series of chemical events that lead to ozone. Thus, strategies to reduce ozone in the atmosphere often lead to visibility improvements. The large increase in area sources is again related to population increases. Use of solvents such as in painting, dry cleaning, charcoal lighter, and windshield washer fluids, and many home use products, show up in the area source category and increases in this area are linked to population growth.

Figure 5-4 Colorado Primary Organic Aerosol (POA) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide POA Emissions		
	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	17	3	-83%
Area	8,432	8,738	4%
On-Road Mobile	1,280	1,288	1%
Off-Road Mobile	1,286	843	-34%
WRAP Area O&G	-	-	-
Road Dust	102	135	33%
Fugitive Dust	777	677	-13%
Anthro Fire	850	621	-27%
Natural Fire	30,581	30,581	0%
Biogenic	-	-	-
Total:	**43,325**	**42,886**	**-1%**

Primary Organic Aerosols (POAs) are organic carbon particles emitted directly from the combustion of organic material. A wide variety of sources contribute to this classification including cooking of meat to diesel emissions and combustion byproducts from wood and agricultural burning. Area sources and automobile emissions dominate this classification. Increases in areas sources are due to population increases. These increases are offset by expected improvements in automobile emissions and by 2018 emissions from this category are expected to decline by about 5%.

Figure 5-5 Colorado Elemental Carbon (EC) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
	Statewide EC Emissions		
Source Category	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	-	-	-
Area	1,264	1,325	5%
On-Road Mobile	1,448	408	-72%
Off-Road Mobile	3,175	1,344	-58%
WRAP Area O&G	-	-	-
Road Dust	9	11	33%
Fugitive Dust	53	46	-13%
Anthro Fire	92	74	-20%
Natural Fire	6,337	6,337	0%
Biogenic	-	-	-
Total:	**12,377**	**9,545**	**-23%**

Elemental carbon is the carbon black, or soot, a byproduct of incomplete combustion. It is the partner to primary organic aerosols and represents the more complete combustion of fuel producing carbon particulate matter as the end product. A carbon particle has a sixteen times greater impact on visibility than a coarse particle of granite has. Emissions, and reductions, in this category are dominated by mobile sources and expected new federal emission standards for mobile sources, especially for diesel engines, along with fleet replacement are the reason for these reductions.

Figure 5-6 Colorado Soil (PM Fine) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
	Statewide Soil (fine PM) Emissions		
Source Category	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	6	85	1404%
Area	4,170	4,311	3%
On-Road Mobile	-	-	-
Off-Road Mobile	-	-	-
WRAP Area O&G	-	-	-
Road Dust	1,082	1,435	33%
Fugitive Dust	13,401	11,679	-13%
Windblown Dust	15,105	15,105	0%
Anthro Fire	253	169	-33%
Natural Fire	1,948	1,948	0%
Biogenic	-	-	-
Total:	**35,964**	**34,732**	**-3%**

Fine soil emissions are largely related to agricultural and mining activities, windblown dust from construction areas and emissions from unpaved and paved roads. A particle of fine dust has a relative impact on visibility one tenth as great as a particle of elemental carbon. Monitoring at all sites in Colorado indicates soil is present as a small but measurable part of the visibility problem. On any given visibility event where poor visual air quality is present in a scene, the impact of dust can vary widely. Overall, on the 20% worst days, fine soil has about the same impact as nitrate particles. Agricultural activities, dust from unpaved roads and construction are prevalent in this source category and changes in emissions are tied to population and vehicle miles traveled. Since soil emissions are not directly from the tailpipe of the vehicle, the category of mobile sources does not show any emissions and all vehicle related emissions from paved and unpaved roads show up in the fugitive dust category.

Figure 5-7 Colorado Coarse Mass (PM Coarse) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	**Statewide Coarse PM Emissions**		
	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	21,096	26,828	27%
Area	1,363	1,388	2%
On-Road Mobile	794	917	15%
Off-Road Mobile	-	-	-
WRAP Area O&G	-	-	-
Road Dust	8,930	11,826	32%
Fugitive Dust	67,642	67,910	0%
Windblown Dust	135,945	135,945	0%
Anthro Fire	51	32	-37%
Natural Fire	5,973	5,973	0%
Biogenic	-	-	-
Total:	**241,794**	**250,818**	**4%**

Particulate matter, also identified as coarse mass particles emissions, are closely related to the same sources as fine soil emissions but other activities like rock crushing and processing, material transfer, open pit mining and unpaved road emissions can be prominent sources. Coarse mass particles travel shorter distances in the atmosphere than some other smaller particles but can remain in the atmosphere sufficiently long enough to play a role in regional haze. Coarse mass particulate matter has the smallest direct impact on regional haze on a particle-by-particle basis where one particle of coarse mass has a relative visibility weight of 0.6 compared to a carbon particle having a weight of 10. Nevertheless, they are commonly present at all monitoring sites and are a greater contributor to regional haze than the fine soil component. Substantial increases in coarse mass are seen in the fugitive dust category. This is due to the fact that construction and emissions from paved and unpaved roads are lined to population, vehicle miles traveled and employment data. Growth in these factors results in these categories increasing from 2002 to 2018. For this planning period, the state evaluated PM from stationary sources, but not from natural sources.

Figure 5-8 Colorado Ammonia (NH3) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
	Statewide Ammonia Emissions		
Source Category	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	453	571	26%
Area	60,771	60,791	0%
On-Road Mobile	4,317	5,894	37%
Off-Road Mobile	43	60	38%
WRAP Area O&G	-	-	-
Road Dust	-	-	-
Fugitive Dust	-	-	-
Anthro Fire	137	95	-31%
Natural Fire	1,965	1,965	0%
Biogenic	-	-	-
Total:	**67,686**	**69,375**	**2%**

Ammonia emissions come from a variety of sources including wastewater treatment facilities, livestock operations, and fertilizer application and to a small extent, mobile sources. Increases in ammonia emission from the base case year to 2018 are linked to population statistics and increased vehicular traffic. Ammonia is directly linked to the production of ammonium nitrate and ammonium sulfate particles in the atmosphere when sulfur dioxide and nitrogen oxides eventually convert over to these forms of particles. Expected growth in the mobile source emissions from 2002 to 2018 is due to the fact that no specific controls on mobile sources are implemented and increases in vehicle miles traveled links directly to increased ammonia emissions.

Chapter 6 Best Available Retrofit Technology

6.1 Introduction

One of the principal elements of Section 169A of the 1977 Clean Air Act Amendments addresses the installation of Best Available Retrofit Technology (BART) for certain existing sources of pollution. The provision, 169A (b)(2), demonstrates Congress' intent to focus attention directly on pollution from a specific group of existing sources. The U.S. Environmental Protection Agency's (EPA) Regional Haze Rule requires certain emission sources that may reasonably be anticipated to cause or contribute to visibility impairment in downwind Class I areas to install BART. *See* 40 CFR §51.308(e); *see also* 64 Fed. Reg. 35714 *et seq.* (July 1, 1999). These requirements are intended to reduce emissions from certain large sources that, due to age, were exempted from other requirements of the Clean Air Act.

BART requirements pertain to 26 specified major point source categories including power plants, cement kilns and industrial boilers. To be considered BART-eligible, sources from these categories must have the potential to emit 250 tons or more of haze forming pollution and must have commenced operation in the 15-year period prior to August 7, 1977.

Because of the regional focus of this requirement in the Regional Haze Rule, BART applies to a larger number of sources than the Phase 1 reasonably attributable visibility impairment requirements. In addition to source-by-source command and control BART implementation, EPA has allowed for more flexible alternatives if they achieve greater progress toward the state's visibility goals than the standard BART approach.

This document demonstrates how Colorado has satisfied the BART requirements in EPA's Regional Haze Rule. Colorado's review process is described and a list of BART-eligible sources is provided. A list of sources that are subject to BART is also provided, along with the requisite modeling analysis approach and justification.

6.2 Overview of Colorado's BART Regulation

Colorado's Air Quality Control Commission approved a State-only BART regulation (Regulation 3 Part F) on March 16, 2006, that became effective in May 2006. A summary of the Colorado BART program and determinations is set out below, in Section 6.3. More detail is provided in Regulation Number 3 Part F, Appendix C to this document, the Technical Support Document (TSD), and at the Division's BART website at: http://www.cdphe.state.co.us/ap/RegionalHazeBART.html.

Colorado's BART Rule includes the following major provisions:

1. Visibility impairing pollutants are defined to include SO2, NOx and particulate matter.
2. Visibility impact levels are established for determining whether a given source causes or contributes to visibility impairment for purposes of the source being

subject-to-BART (or excluded). The causation threshold is 1.0 deciview and the contribution threshold is 0.5 deciview. Individual sources are exempt from BART if the 98th percentile daily change in visibility from the facility, as compared against natural background conditions, is less than 0.5 deciview at all Class I federal areas for each year modeled and for the entire multi-year modeling period.

3. BART controls are established based on a case-by-case analysis taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, the remaining useful life of the source or unit, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. These factors are established in the definition of Best Available Retrofit Technology.
4. Provision that the installation of regional haze BART controls exempts a source from additional BART controls for regional haze, but does not exempt a source from additional controls or emission reductions that may be necessary to make reasonable progress under the regional haze SIP.

6.3 Summary of Colorado's BART Determinations

Colorado's Air Quality Control Commission elected to assume that all BART-eligible sources are subject to BART, but required the Division to perform modeling to determine whether BART-eligible sources will cause or contribute to visibility impairment at any Class I area. The threshold for causing or contributing to impairment was 0.5 or greater deciview impact. BART-eligible sources that did not cause or contribute 0.5 or greater deciview impact would not be subject to BART.

Once the complete list of eligible sources had been assembled, the list was reviewed to determine the current status of each source. A number of sources were eliminated for various reasons. One plant was being shut down. Two others were found not to be subject to BART because the size of the boilers was less than the 250 MMBtu/hour limit identified in the EPA BART Rule. Two sources were not subject to BART because they had been re-constructed after the BART period, and two were exempt because VOCs are not a visibility impairing pollutant under Colorado's BART Rule. The final list of sources was modeled by the Division to determine if they met the "cause or contribute" criteria. The results of this modeling are reflected in Table 6 - 1 below.

Table 6 - 1 Results of Subject-to-BART Modeling

Modeled BART–Eligible Source	Division Modeling (98th percentile delta-deciview value)	Division Approved Refined Modeling from Source Operator (98th percentile delta-deciview value)	Contribution Threshold (deciviews)	Impact Equal to or Greater Than Contribution Threshold?
CEMEX - Lyons Cement Kiln & Dryer	1.533		0.5	Yes
CENC (Trigen-Colorado) Units 4 & 5	1.255		0.5	Yes
Cherokee Station – Unit 4	1.460		0.5	Yes
Comanche Station – Units 1 and 2	0.701		0.5	Yes
Craig Station – Units 1 & 2	2.689		0.5	Yes
Hayden Station – Units 1 & 2	2.538		0.5	Yes
Lamar Light & Power – Unit 6	0.064		0.5	No
Martin Drake Power Plant – Units 5, 6 & 7	1.041		0.5	Yes
Pawnee Station – Unit 1	1.189		0.5	Yes
Ray D. Nixon Power Plant – Unit 1	0.570	0.481	0.5	No
Suncor Denver Refinery	0.239		0.5	No
Valmont Station – Unit 5	1.591		0.5	Yes

Notes:

1. The contribution threshold has an implied level of precision equal to the level of precision reported from the model.
2. Source operator modeling results are shown only if modeling has been approved by Division.
3. Roche is not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment.
4. Denver Steam is not included because it is exempt by rule (natural gas only <250 MMBtu).
5. Holcim Cement (Florence) and Rocky Mountain Steel Mills (Pueblo) are not included because of facility reconstruction.
6. Changes to the Ray D. Nixon Power Plant modeling included refinement of the meteorological fields and emission rates. The Division has issued a permit modification for this facility that includes a 30-day rolling emission limit for SO2.
7. Suncor Denver Refinery (including the former Valero Refinery) was not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment. Moreover, Suncor has installed controls to comply with MACT standards.

Of the BART-eligible sources listed above, those sources with a visibility contribution threshold equal to or greater than 0.5 deciview were determined to be subject-to-BART. Tables 6 - 2 and 6 - 3 include the BART determinations that will apply to each source.

Table 6 - 2 BART Determinations for Colorado Sources					
Emission Unit	**Assumed ** NOx Control Type**	**NOx Emission Limit**	**Assumed ** SO_2 Control Type**	**SO_2 Emission Limit**	**Assumed ** Particulate Control and Emission Limit**
Cemex - Lyons Kiln	Selective Non-Catalytic Reduction System	255.3 lbs/hr (30-day rolling average) 901.0 tons/yr (12-month rolling average)	None	25.3 lbs/hr (12-month rolling average) 95.0 tons/yr (12-month rolling average)	Fabric Filter Baghouse * 0.275 lb/ton of dry feed 20% opacity
Cemex - Lyons Dryer	None	13.9 tons/yr	None	36.7 tons/yr	Fabric Filter Baghouse* 22.8 tons/yr 10% opacity
CENC Unit 4	Low NOx Burners with Separated Over-Fire Air	0.37 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
CENC Unit 5	Low NOx Burners with Separated Over-Fire Air, and Selective Non-Catalytic Reduction System	0.19 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
Comanche Unit 1	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu

Table 6 - 2 BART Determinations for Colorado Sources					
Emission Unit	**Assumed ** NOx Control Type**	**NOx Emission Limit**	**Assumed ** SO_2 Control Type**	**SO_2 Emission Limit**	**Assumed ** Particulate Control and Emission Limit**
Comanche Unit 2	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 1	Selective Non-Catalytic Reduction System	0.28 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 2	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 1	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 2	Selective Catalytic Reduction System	0.07 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 5	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Dry Sorbent Injection	0.26 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 6	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 7	Ultra Low-NOx Burners (including Over-Fire Air)	0.29 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu

* Controls are already operating

** Based on the state's BART analysis, the "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

Table 6 - 3 BART Determinations for PSCo's BART Alternative Sources [5, 6, 7]					
Emission Unit	**NOx Control Type**	**NOx Emission Limit**	**SO_2 Control Type**	**SO_2 Emission Limit**	**Particulate Control and Emission Limit**
Cherokee Unit 1	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012
Cherokee Unit 2	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011
Cherokee Unit 3	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016
Cherokee Unit 4	Natural Gas Operation 12/31/2017	0.12 lb/MMBtu (30-day rolling average) by 12/31/2017	Natural Gas Operation 12/31/2017	7.81 tpy (rolling 12 month average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas Operation 12/31/2017
Valmont Unit 5	Shutdown 12/31/2017	0	Shutdown 12/31/2017	0	Shutdown 12/31/2017
Pawnee Unit 1	SCR**	0.07 lb/MMBtu (30-day rolling average) by 12/31/2014	Lime Spray Dryer**	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	Fabric Filter Baghouse* 0.03 lbs/MMBtu
Arapahoe Unit 3	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Arapahoe Unit 4	Natural Gas Operation	600 tpy (rolling 12 month average) 12/31/2014	Natural Gas operation 12/31/2014	1.28 tpy (rolling 12 month average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas operation 12/31/2014

* Controls are already operating

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the above table is not a requirement.

For all BART and BART alternative determinations, approved in the Federal State Implementation Plan, the state affirms that the BART emission limits satisfy Regional Haze requirements for this planning period (through 2017) and that no other Regional

[5] Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.
[6] 500 tpy NOx will be reserved from Cherokee station for netting or offsets.
[7] 300 tpy NOx will be reserved from Arapahoe station for netting or offsets for additional natural gas generation.

Haze analyses or Regional Haze controls will be required by the state during this timeframe.

6.4 Overview of Colorado's BART Determinations

Colorado has been evaluating BART issues for many years and has closely followed EPA's proposals and final rules. The list of Colorado BART-eligible sources has been well known since the 1990's, based on EPA's expected applicability dates of between August 7, 1962 and August 7, 1977. Colorado has been involved in four BART-like proceedings involving known BART sources. Two of these determinations resulted from actions related to the Hayden and Craig power plants. These plants were identified in a certification of impairment made by the U.S. Forest Service regarding visibility impacts at Mt. Zirkel Wilderness Area, located northeast of Steamboat Springs. Colorado conducted two additional BART proceedings for all sources in 2007 and in 2008, which were submitted to EPA for approval. A number of these determinations were revised in 2010 based on adverse comments from EPA; Table 6-2 presents the 2010 BART determinations.

6.4.1 The State's Consideration of BART Factors

In identifying a level of control as BART, States are required by section 169A(g) of the Clean Air Act to "take into consideration" the following factors:

(1) The costs of compliance,
(2) The energy and non-air quality environmental impacts of compliance,
(3) Any existing pollution control technology in use at the source,
(4) The remaining useful life of the source, and
(5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

42 U.S.C. § 7491(g)(2).

Colorado's BART regulation requires that the five statutory factors be considered for all BART sources. *See,* Regulation No. 3, Part E, Section IV.B.1. In making its BART determination for each Colorado source, the state took into consideration the five statutory factors on a case-by case basis, and for significant NOx controls the Division also utilized the guidance criteria set forth in Section 6.4.3 consistent with the five factors. Summaries of the state's facility-specific consideration of the five factors and resulting determinations for each BART source are provided in this Chapter 6. Documentation reflecting the state's analyses and supporting the state's BART determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix C of this document.

6.4.1.1 The costs of compliance. The Division requested, and the companies provided, source-specific cost information for each BART unit. The cost information ranged from the installation and operation of new SO2 and NOx control equipment to upgrade analyses of existing SO2 controls. The cost for each unit is summarized below, and the state's consideration of this factor for each source is presented in detail in Appendix C.

6.4.1.2 The energy and non-air quality environmental impacts of compliance. This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each BART unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO2, as further described below.

6.4.1.3 Any existing pollution control technology in use at the source. The state has taken into consideration the existing PM, SO2 and NOx pollution control equipment in use at each Colorado source, as part of its BART determination process.

The Division has reviewed available particulate controls. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM" s*ee* 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix C.

The Division also reviewed various SO2 controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 6, in Appendix C and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. *See* 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix C.

With respect to NOx controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NOx controls, as appropriate

When determining the emission rates for each source, the state referred to and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that BART relates to retrofitting sources (vs. new or reconstructed facilities), a review of other determinations was used to better substantiate the source specific information provided by the source.

6.4.1.4 The remaining useful life of the source. None of Colorado's BART sources are expected to retire over the next twenty years. Therefore, this factor did not affect any of the state's BART determinations.

6.4.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of BART. The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of BART. Modeling information for each BART determination is presented below and in Appendix C.

6.4.2 SIP Requirements from EPA's Regional Haze Rule

The following section includes information addressing the SIP elements contained in EPA's Regional Haze Rule. The section numbers refer to provisions in 40 CFR § 51.308(e), the BART provision of the Regional Haze Rule.

(i) A list of all BART-eligible sources within the State.

Table 6 - 3 below lists the initial group of Colorado sources subject to BART. This initial list was created based on historical information contained in the Division's source files and is based on the 1962-1977 time frame and source category list contained in Appendix Y. This list was then examined to see if any of the sources identified would be exempt from BART. EPA allows sources to be exempt from BART if they have undergone permitted reconstruction, emit *de minimis* levels of pollution, or are fossil-fuel boilers with an individual heat input rating below 250 million Btu/hour. Colorado's BART rule allows sources to be exempt from BART if modeling demonstrates the impact at any Class I area is below the "cause or contribute" thresholds of 1.0 and 0.5 deciviews. Table 6 - 3 lists the current status of the original BART sources and notes which sources were exempted and why.

Table 6 - 4 Colorado's BART Eligible Sources

Plant Name	Source Owner	Rating, Heat Input or Source type	Start Year	Current Status
Cemex - Lyons Kiln	Cemex	Portland Cement	<1977	Subject-to-BART
Cemex - Lyons Dryer	Cemex	Portland Cement	<1977	Subject-to-BART
CENC Unit 4	Colorado Energy Nations Company (CENC)	360 MMBtu/hr	1975	Subject-to-BART
CENC Unit 5	CENC	650 MMBtu/hr	1979	Subject-to-BART
Cherokee Unit 4	Public Service Company of Colorado (PSCO)	350 MW	1968	Subject-to-BART
Comanche Unit 1	PSCO	350 MW	1973	Subject-to-BART
Comanche Unit 2	PSCO	350 MW	1976	Subject-to-BART
Craig Unit 1	Tri-State Generation and	446 MW	1979	Subject-to-BART

Table 6 - 4 Colorado's BART Eligible Sources				
Plant Name	**Source Owner**	**Rating, Heat Input or Source type**	**Start Year**	**Current Status**
	Transmission, Inc.			
Craig Unit 2	Tri-State	446 MW	1979	Subject-to-BART
Hayden Unit 1	PSCO	190 MW	1965	Subject-to-BART
Hayden Unit 2	PSCO	275 MW	1976	Subject-to-BART
Martin Drake Unit 5	Colorado Springs Utilities (CSU)	55 MW	1962	Subject-to-BART
Martin Drake Unit 6	CSU	85 MW	1968	Subject-to-BART
Martin Drake Unit 7	CSU	145 MW	1974	Subject-to-BART
Pawnee Unit 1	PSCO	500 MW	1981	BART Alternative
Valmont Unit 5	PSCO	188 MW	1964	Subject-to-BART
Denver Steam Unit 1	PSCO	Steam only 210 MMBtu/hr	1972	Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110
Denver Steam Unit 2	PSCO	Steam only 243 MMBtu/hr	1974	Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110
Holcim Kiln	Holcim	Portland Cement	<1977	Not subject-to-BART since Kiln built after BART time period. Other sources < 250 TPY total emissions.
Lamar Utilities	City of Lamar	25 MW	1972	Plant will be shutdown; so will no longer be subject.
Oregon Steel	Oregon Steel	Steel Mfg.	<1977	Not subject-to-BART since Arc furnace rebuilt after BART time period. Other sources < 250 TPY total emissions.
Ray Nixon Unit 1	CSU	227 MW	1980	Not Subject-to-BART (enforceable emission limitations and refined CALPUFF modeling result in less than 0.5 dv visibility impact)
Roche	Roche	Pharmaceutic al Mfg.	<1977	Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO
Suncor/Valero	Suncor	Refinery	<1977	Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO

(ii) *A determination of BART for each BART-eligible source.*

Table 6 - 2 lists the state's BART determinations for sources that cause or contribute to visibility impairment in Class I areas.

(iii) *The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

Summaries of the state's facility-specific consideration of the five factors and resulting determinations are provided in this chapter 6. Documentation reflecting the state's analyses and supporting the state's BART determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix C of this document.

(iv) *The determination of BART for fossil-fuel fired power plants having a total generating capacity greater than 750 megawatts must be made pursuant to the guidelines in Appendix Y of this part (Guidelines for BART Determinations Under the Regional Haze Rule).*

Colorado has only one source with two BART eligible EGUs that have a combined rating exceeding 750 MW, which is Tri-State Generation and Transmission Association's Craig plant located in Moffat County. The Division's BART determination for the Craig facility is discussed in more detail below.

(v) *A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.*

This requirement is addressed in Colorado's BART Rule, and Regulation No. 3 Part F Section VI.

(vi) *A requirement that each source subject-to-BART maintain the control equipment required by this subpart and establish procedures to ensure such equipment is properly operated and maintained.*

Operation and maintenance plans are required by the BART Rule, and Regulation No. 3. Part F Section VII.

6.4.3 Overview of the BART Determinations and the Five Factor Analyses for Each BART Source

This section presents an overview of the BART determinations for the subject to BART sources.

The Regional Haze rule requires states to make determinations about what is appropriate for BART, considering the five statutory factors:

(1) The costs of compliance,
(2) The energy and non-air quality environmental impacts of compliance,
(3) Any existing pollution control technology in use at the source,
(4) The remaining useful life of the source, and

(5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

The rule gives the states broad latitude on how the five factors are to be considered to determine the appropriate controls for BART. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the five factors in reaching a determination.[8] The manner and method of consideration is left to the state's discretion; states are free to determine the weight and significance to be assigned to each factor.[9]

For the purposes of the five factor review for the three pollutants that the state is assessing for BART, SO2 and PM have been assessed utilizing the five factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO2 and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NOx controls on BART electric generating units, for reasons described below, the state is employing guidance criteria to aid in its assessment and determination of BART using the five factors for these sources, largely because significant NOx add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of BART for these sources.

With respect to SO2 emissions, there are currently ten lime spray dryer (LSD) SO2 control systems operating at electric generating units in Colorado.[10] There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO2 emissions in the state and other non-air quality considerations. Each of these systems will meet EPA's presumptive limits, and in some cases surpass those limits.[11] The

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[8] The EPA "BART Guidelines" provide information relating to implementation of the Regional Haze rule, which the state has considered. However, Colorado also notes that Appendix Y is expressly not mandatory with respect to EGUs of less than 750 MWs in size, and Craig Station (Tri-State Generation and Transmission) is the only such BART electric generating unit in the state. *See* 70 Fed. Reg. at 39108. Thus, the state has substantial discretion in how it considers and applies the five factors (and any other factors that it deems relevant) to BART electric generating units in the state that are below this megawatt threshold, and for non-EGU sources. *See, e.g., id.* at 39108, 39131 and 39158.

[9] *See, e.g.*, 70 Fed. Reg. at 39170.

[10] EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, Valmont Unit 5.

[11] In preparing Appendix Y, EPA conducted extensive research and analysis of emission controls on BART sources nationwide, including all BART EGU sources in Colorado. *See* 70 Fed. Reg. at 39134. Based upon this analysis, EPA established presumptive limits that it deems to be appropriate for large EGU sources of greater than 750 MW, including sources greater than 200 MW located at such plants. EPA's position is that the presumptive limits are cost effective and will lead to a significant degree of visibility improvement. *Id. See also,* 69 Fed. Reg. 25184, 25202 (May 5, 2004); *Technical Support Document for BART NOx Limits for Electric Generating Units* and *Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet*, Memorandum to Docket OAR 2002-0076, April 15, 2006; *Technical Support Document for BART SO2 Limits for Electric Generating Units*,

Division has determined in the past that these systems can be cost-effective for Colorado's BART sources, and the Air Quality Control Commission approved LSD systems as BART for Colorado Springs Utilities' Martin Drake Units #6 and #7 in 2008. With this familiarity and use of the emissions control technology, the state has assessed SO2 emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources, typically exceeding a control efficiency of 95%. The emission limits for these units reflect the 95% or greater control efficiency and are therefore stringent and appropriate. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado, and the Air Quality Control Commission approved these systems as BART in 2007. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM emissions was not necessary for Colorado's BART-subject units.

With respect to NOx emissions, post-combustion controls for NOx are generally not employed in Colorado at BART or other significant coal-fired electric generating units. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NOx emissions.

In assessing and determining appropriate NOx BART controls for individual units for visibility improvement under the regional haze rule, the state has considered the five statutory factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight.[12] In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors. More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (*e.g.*, expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NOx) from the atmosphere, or $/ton of NOx removed); and, (ii) visibility improvement

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Memorandum to Docket OAR 2002-0076, April 1, 2006; and *Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations*, U.S. EPA, June 2005.

[12] *See* 70 Fed. Reg. at 39170 and 39137.

expected from the control options analyzed (*e.g.*, expressed as visibility improvement in delta deciview (Δdv) from CALPUFF air quality modeling).

- Accordingly, as part of its five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.For the highest-performing NOx post-combustion control options (*i.e*., SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NOx post-combustion control options (*e.g*., SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state's general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of BART on a case by case basis.

The cost criteria presented above is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls. For example, the $5,000/ton criterion is consistent with Colorado's retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.[13] In that case, a $5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.[14] The $5,000/ton criterion is also consistent and within the range of the state's implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control costs for Colorado RACT can be in the range of $5,000/ton (and lower), while control costs for Colorado BACT can be in the range of $5,000/ton (and higher).

In addition, as it considers the pertinent factors for regional haze, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NOx controls, *i.e*., SCR, has the ability to provide significant NOx reductions, but also has initial capital dollar requirements that can

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[13] Air Quality Control Commission Regulation No. 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

[14] The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

approach or exceed $100 million per unit.[15] The lesser-performing post-combustion NOx controls, *e.g.*, SNCR, reduce less NOx on a percentage basis, but also have substantially lower initial capital requirements, generally less than $10 million.[16] The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NOx controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.[17] For the lesser-performing add-on NOx controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area.

Employing the foregoing guidance criteria for post-combustion NOx controls, as part of considering the five factors under the Regional Haze rule, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

6.4.3.1 BART Determination for Cemex's Lyons Cement Plant

The Cemex facility manufactures Portland cement and is located in Lyons, Colorado, approximately 20 miles from Rocky Mountain National Park. The Lyons plant was originally constructed with a long dry kiln. This plant supplies approximately 25% of the clinker used in the regional cement market. There are two BART eligible units at the facility: the dryer and the kiln.

In 1980, the kiln was cut to one-half its original length, and a flash vessel was added with a single-stage preheater. The permitted kiln feed rate is 120 tons per hour of raw material (kiln feed), and on average yields approximately 62 tons of clinker per hour. The kiln is the main source of SO2 and NOx emissions. The raw material dryer emits minor amounts of SO2 and NOx; in 2008 Cemex reported SO2 and NOx emissions from the dryer as 0.89 and 10.41 tons per year respectively based on stack test results. Due to the low emission rates from the dryer the BART review focuses on the kiln.

Newer multistage preheater/precalciner kilns are designed to be more energy efficient and yield lower emissions per ton of clinker due to this when compared to the Cemex

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[15] *See, e.g.,* Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, $83MM; Public Service of Colorado, Hayden Unit #2, $72MM; Tri-State Generation and Transmission, Craig Station Unit #1, $210MM.

[16] *See, e.g.*, Appendix C, reflecting CENC (Tri-gen), Unit #4, $1.4MM; Public Service Company of Colorado, Hayden Unit #2, $4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, $13.1MM

[17] The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. The state relied upon this threshold when determining which Colorado's BART eligible sources became subject to BART. *See*, Air Quality Control Commission Regulation No. 3, Section III.B.1.b. Thus, a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

Lyons kiln. The newer Portland cement plants studied by EPA, utilize multistage preheater/precalciner designs that are not directly comparable. Cemex has a unique single stage preheater/precalciner system with different emission profiles and energy demands. New Portland cement plants have further developed the preheater/precalciner design with multiple stages to reduce emissions and energy requirements for the process. Additionally, new plant designs allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing NOx to elemental Nitrogen.

Cemex submitted a BART analysis to the Division on August 1, 2006, with revisions submitted on August 28, 2006; January 15, 2007; October 2007 and August 29, 2008. In response to a Division request, Cemex submitted additional information on July 27 and 28, 2010

CALPUFF modeling provided by the source, using a maximum SO2 emission rate of 123.4 lbs/hour for both the dryer and kiln combined indicates a 98th percentile visibility impact of 0.78 delta deciview (Δdv) at Rocky Mountain National Park. The modeled 98th percentile visibility impact from the kiln is 0.76 Δdv. Thus, the visibility impact of the dryer alone is the resultant difference which is 0.02 Δdv. Because the dryer uses the cleanest fossil fuel available and post combustion controls on such extremely low concentrations are not practical, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable controls on the dryer. Accordingly, the state has determined that no additional emission control analysis of the dryer is necessary or appropriate since the total elimination of the emissions would not result in any meaningful visibility improvement which is a fundamental factor in the BART evaluation. For the dryer, the BART SO2 emission limitation is 36.7 tpy and the BART NOx emission limitation is 13.9 tpy, which are listed in the existing Cemex Title V permit.

SO2 BART Determination for Cemex Lyons - Kiln

Lime addition to kiln feed, fuel substitution (coal with tire derived fuel), dry sorbent injection (DSI), and wet lime scrubbing (WLS) were determined to be technically feasible for reducing SO2 emissions from Portland cement kilns.

The following table lists the most feasible and effective options:

Cemex Lyons -Kiln				
SO2 Control Technology	Estimated Control Efficiency	Annual Controlled Hourly SO2 Emissions (lbs/hr)	Annual Controlled SO2 Emissions (tpy)	Annual Controlled SO2 Emissions (lb/ton of Clinker)
Baseline SO2 Emissions		25.3	95.0	0.40
Lime Addition to Kiln Feed	25%	18.9	71.3	0.30
Fuel Substitution (coal with TDF)	40%	15.2	57.0	0.24

Cemex Lyons -Kiln				
SO2 Control Technology	Estimated Control Efficiency	Annual Controlled Hourly SO2 Emissions (lbs/hr)	Annual Controlled SO2 Emissions (tpy)	Annual Controlled SO2 Emissions (lb/ton of Clinker)
Dry Sorbent Injection	50%	12.6	47.5	0.20
Wet Lime Scrubbing (Tailpipe scrubber)	90%	2.5	9.5	0.04

The energy and non-air quality impacts of the alternatives are as follows:

- Lime addition to kiln feed and dry sorbent injection - there are no energy or non-air quality impacts associated with these control options
- Wet lime scrubbing - significant water usage, an additional fan of considerable horsepower to move the flue gas through the scrubber, potential increase in PM emissions and sulfuric acid mist
- Tire-derived fuel – the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. *See,* Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.

There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period. Cemex's limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the SO2 emission reduction, annualized costs and the control cost effectiveness for the feasible controls:

Cemex Lyons - Kiln				
SO2 Control Technology	SO2 Emission Reduction (tons/yr)	Annualized Cost ($/yr)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline SO2 Emissions	-			
Lime Addition to Kiln Feed	23.8	$3,640,178	$153,271	
Fuel Substitution (coal supplemented with TDF)	38.0	$172,179	$4,531	$243,368
Dry Sorbent Injection	47.5	Not provided	-	
Wet Lime Scrubbing (Tailpipe scrubber)	85.5	$2,529,018	$29,579	$49,618

The following table lists the projected visibility improvements for SO2 controls:

Cemex Lyons - Kiln		
SO2 Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (Δdv)
Maximum (24-hr max)	0.760	
Baseline (95 tpy)*	0.731	-
Lime Addition to Kiln Feed (71.3 tpy)*	0.727	0.033
Fuel Substitution (57 tpy)*	0.725	0.034
Dry Sorbent Injection (47.5 tpy)*	0.725	0.036
Wet Lime Scrubbing (9.5 tpy)*	0.720	0.040

** Visibility impacts rescaled from original BART modeling*

For the kiln, based upon its consideration and weighing of the five factors, the state has determined that no additional SO2 emissions control is warranted as the added expense of these controls were determined to not be reasonable for the small incremental visibility improvement of less than 0.04 deciviews. However, the use of low sulfur coal and the inherent control resulting from the Portland cement process provides sufficient basis to establish annual BART SO2 emission limits for the kiln of:

25.3 lbs/hour and

95.0 tons of SO2 per year

No additional controls are warranted because 80% of the sulfur is captured in the clinker, making the inherent control of the process the SO2 control. Additional SO2 scrubbing is also provided by the limestone coating in the baghouse as the exhaust gas passes through the baghouse filter surface.

SO2 BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the SO2 BART requirement is 36.7 tpy, which is taken from the existing Title V permit.

Particulate Matter BART Determination for Cemex Lyons - Kiln and Dryer

The state has determined that the existing fabric filter baghouses and the existing regulatory emissions limits of 0.275 lb/ton of dry feed and 20% opacity for the kiln and 10% opacity for the dryer represent the most stringent control option. The kiln and dryer baghouses exceed a PM control efficiency of 95%, and the emission limits are BART for PM/PM_{10}. The state assumes that the BART emission limits can be achieved through the operation of the existing fabric filter baghouse.

NOx BART Determination for Cemex Lyons - Kiln

Water injection, firing coal supplemented with tire-derived fuel (TDF), indirect firing with low NOx burners, and selective non-catalytic reduction (SNCR) were determined to be technically feasible and appropriate for reducing NOx emissions from Portland cement kilns. As further discussed in Appendix C, the state has determined that SCR is not commercially available for Portland cement kilns. Presently, SCR has not been applied to a cement plant of any type in the United States. Cemex notes that the major SCR vendors have indicated that SCR is not commercially available for cement kilns at this time. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe, constitutes "available" control technology for purposes of BART. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is "available" for purposes of retrofitting such control technology on an existing source. Accordingly, the state has eliminated SCR as an available control technology for purposes of BART. Moreover, as further discussed in Appendix C, if SCR were considered commercially available, it is not technically feasible for the Lyons facility due to the unique design of the kiln.

The following table lists the most feasible and effective options:

Cemex Lyons - Kiln				
NOx Control Technology	Estimated Control Efficiency	Annual Controlled Hourly NOx Emissions (lbs/hr)	Annual Controlled NOx Emissions (tpy)	Annual Controlled NOx Emissions (lb/ton of Clinker)
Baseline NOx Emissions	-	464.3	1,747.1	7.39
Water Injection	7.0%	431.8	1,624.8	6.87
Coal w/TDF	10.0%	417.8	1,572.3	6.65
Indirect Firing with LNB	20.0%	371.4	1,397.6	5.91
SNCR (30-day rolling)	45.0%	255.3	960.9	4.06
SNCR (12-month rolling)	48.4%	239.4	901.0	3.81
SNCR w/LNB	55%	208.9	786.2	3.33

The energy and non-air quality impacts of the alternatives are as follows:

- Low-NOx burners - there are no energy or non-air quality impacts
- Water injection - significant water usage
- Tire-derived fuel – the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. *See,* Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.
- SNCR - none

There are no remaining useful life issues for the alternatives as the state has presumed that the source will remain in service for the 20-year amortization period. Cemex's limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

Cemex Lyons - Kiln				
NOx Control Technology	NOx Emission Reduction	Annualized Cost	Cost Effectiveness	Incremental Cost Effectiveness
	(tons/yr)	($/yr)	($/ton)	($/ton)
Baseline NOx Emissions	-			
Water Injection	122.3	$43,598	$356	-
Coal w/TDF	174.7	$172,179	$986	$2,453
Indirect Firing with LNB	349.4	$710,750	$2,034	$3,083
SNCR (45.0% control)	786.2	$1,636,636	$2,082	$2,120
SNCR (48.4% control)	846.1	$1,636,636	$1,934	$1,864
SNCR w/LNB (55.0% control w/uncertainty)	960.9	$1,686,395	$1,755	$434

The following table lists the projected visibility improvements for NOx controls for the kiln:

Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (from 24-hr Max) (Δdv)
24-hr Maximum (≈ 656.9 lbs/hr))	0.760	
Revised Baseline (≈ 464.3 lbs/hr)*	0.572	0.188
Original Baseline (≈ 446.8 lbs/hr)*	0.555	0.205
Water Injection (≈ 431.8 lbs/hr)*	0.540	0.220
Firing TDF (≈417.9 lbs/hr)*	0.526	0.234
Indirect Firing with LNB (≈ 371.4 lbs/hr)*	0.481	0.279
Original BART Limit – SNCR (≈ 268.0 lbs/hr)	0.380	0.380
Proposed BART Limit (30-day) – SNCR (≈ 255.3 lbs/hr)**	0.368	0.392
Proposed BART Limit (annual) – SNCR (≈ 239.0 lbs/hr)**	0.352	0.408
SNCR w/LNB (≈208.9 lbs/hr)**	0.322	0.438

The Cemex – Lyons facility is a unique kiln system most accurately described as a modified long dry kiln, the characteristics of a modified long dry kiln system are not similar to either a long wet kiln or a multi stage preheater/precalciner kiln. The temperature profile in a long dry kiln system (>1500°F) is significantly higher at the exit than a more typical preheater precalciner kiln (650°F). This is a significant distinction that limits the location and residence time available for an effective NOx control system. The combination of SNCR with LNB has an uncertain level of control due to unique nature of the Lyons kiln. Furthermore, the associated incremental reduction in NOx emissions associated with SNCR in combination with LNB would afford only a minimal or negligible visibility improvement (less than 0.03 delta deciview). Therefore, the Division believes that SNCR is the best NOx control system available for this kiln.

For the kiln, because of the unique characteristics of the Cemex facility, the state has determined that the BART emission limits for NOx are:

255.3 pounds per hour (30-day rolling average) and

901.0 tons per year (12-month rolling average)

The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This BART determination affords the most NOx reduction from the kiln (846.1 tpy) and contributes significant visibility improvement (0.38 Δdv). The determination affirms a prior Air Quality Control Commission BART determination for SNCR for this facility (2008). The state assumes that the BART emission limits can be achieved through the installation and operation of SNCR.

NOx BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the NOx BART requirement is 13.9 tpy, which is taken from the existing Title V permit.

A complete analysis that further supports the BART determination for the Cemex Lyons facility can be found in Appendix C.

6.4.3.2 BART Determination for Colorado Energy Nations Company (CENC)

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. Initial air dispersion modeling performed by the Division demonstrated that the CENC facility contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Trigen (now CENC) submitted a BART Analysis to the Division on July 31, 2006. CENC also provided information in its "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado" Submittal provided on November 16, 2009, as well as additional information upon the Division's request on February 8, 2010, and May 7, 2010.

The CENC facility includes two coal-fired boilers that supply steam and electrical power to Coors Brewery. The boilers are rated as follows: Unit 4 at 360 MMBtu/hr and Unit 5 at 650 MMBtu/hr. These are approximately equivalent to 35 and 65 MW power plant boilers, based on the design heat rates.

SO2 BART Determination for CENC - Boilers 4 and 5

Dry sorbent injection (DSI) and SO_2 emission management were determined to be technically feasible for reducing SO2 emissions from Boilers 4 and 5. These options were considered as potentially BART by the Division. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible. SO2 emissions management uses a variety of options to reduce SO2 emissions: dispatch natural gas-fired capacity, reduce total system load, and/or recue coal firing rate to maintain a new peak SO2 limit.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

CENC Boiler 4 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SO_2 Emissions Management	1.0	$44,299	$43,690
DSI – Trona	468.0	$1,766,000	$3,774

CENC Boiler 5 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SO_2 Emissions Management	0.8	$65,882	$78,095
DSI – Trona	844.0	$2,094,000	$2,482

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, and fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to DSI are as follows:

SO2 Control Method	CENC - Boiler 4		CENC - Boiler 5	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.90		0.98	
DSI – Trona (annual avg.)	0.26	0.08	0.29	0.13

SO2 emissions management was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement that would result from one tpy or less of SO2 reduction.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

CENC Boiler 4: 1.0 lb/MMBtu (30-day rolling average)

CENC Boiler 5: 1.0 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved without additional control technology. Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement afforded.

Particulate Matter BART Determination for CENC - Boilers 4 and 5

The Division has determined that for Boilers 4 and 5, an emission limit of 0.07 lb/MMBtu (PM/PM10) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM_{10}. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for CENC - Boilers 4 and 5

Low NOx burners (LNB), LNB plus separated overfire air (SOFA), selective non-catalytic reduction (SNCR), SNCR plus LNB plus SOFA, and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at CENC Boilers 4 and 5.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

CENC Boiler 4 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	0	$0
LNB	59.9	$193,433	$3,227
SNCR	179.8	$694,046	$3,860
LNB+SOFA	209.8	$678,305	$3,234
LNB+SOFA + SNCR	368.0	$1,372,351	$3,729
SCR	515.4	$4,201,038	$8,150

CENC Boiler 5 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
LNB	48.4	$249,858	$5,166
LNB+SOFA	127.3	$815,829	$6,383
SNCR	207.3	$923,996	$4,458
LNB+SOFA + SNCR	353.7	$1,739,825	$4,918
SCR	550.0	$6,469,610	$11,764

The energy and non-air quality impacts of the alternatives are as follows:

- LNB – not significant
- LNB + SOFA – may increase unburned carbon in the ash, commonly referred to as loss on ignition
- SNCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	CENC - Boiler 4		CENC - Boiler 5	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx l Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.67		0.66	
LNB (annual avg.)	0.45	0.05	0.30	0.17
SNCR (annual avg.)	0.35	0.07	0.24	0.21
LNB + SOFA (annual avg.)	0.32	0.08	0.24	0.21
LNB + SOFA + SNCR (annual avg.)	0.19	0.12	0.17	0.26
SCR	0.07	0.18	0.07	0.31

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 4 is the following NOx emission rates:

CENC Boiler 4: 0.37 lb/MMBtu (30-day rolling average)

Or

0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air. Although the other alternatives achieve better emissions reductions, achieving lower limits through different controls was determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.04 dv for SNCR and 0.10 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Unit 4.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 5 is the following NOx emission rates:

CENC Boiler 5: 0.19 lb/MMBtu (30-day rolling average)
Or
0.26 lb/MMBtu Boiler 4 and 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air and selective non-catalytic reduction.

For the emission limits above, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria discussed above in section 6.4.3.

- Boiler 5: $4,918 per ton NOx removed; 0.26 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Though SCR achieves better emissions reductions, achieving lower limits through SCR was determined to not fall into the guidance cost and visibility improvement criteria discussed in section 6.4.3.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.05 dv). Thus, it is not warranted to select emission limits associated SCR for CENC Unit 5.

A complete analysis that supports the BART determination for the CENC facility can be found in Appendix C.

6.4.3.3 BART Determination for Public Service Company Comanche Units 1 and 2

Comanche Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. PSCo submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8,

2007. In response to a Division request, PSCo submitted additional information on May 25, and July 14, 2010.

SO2 BART Determination for Comanche - Units 1 and 2

Semi-Dry FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades should be considered for Comanche Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Comanche's dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Comanche, the use of performance additives on the scrubbers would not be expected to increase the SO_2 removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes SO_2 removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO_2. Since NO_2 is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO_2 removal rates, such as those experienced at Comanche. There are no known acceptable reagents without this side effect that would allow additional SO_2 removal in the dry scrubbing systems present at the Comanche Station.
- *Increase the pulverization level of sorbent* – PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system -* The supplier offers no upgrade in atomizer design to improve SO_2 removal at Comanche. PSCo asserts and the state agrees that a third scrubber module on Comanche Units 1 and 2 is not feasible due to the current layout of the ductwork and space constraints around the scrubbers.
- *Additional equipment and maintenance* - Comanche Units 1 and 2 are already achieving 30-day average emission rates of 0.12 lbs/MMBtu, 30-day rolling average, and 0.10 lbs/MMBtu, 12-month average for the two units combined, as adopted in 2007 by the Commission. It is not technically feasible to install an extra scrubber module at the site; therefore no additional equipment or maintenance will decrease SO2 emissions or achieve a lower limit.

Consequently, further capital upgrades to the current high performing SO2 removal system were deemed technically infeasible, and a lower emissions limit is not achievable.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Comanche – Unit 1		Comanche – Unit 2	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.75		0.74	
Semi-Dry FGD (LSD) (annual avg.)	0.12	0.35	0.12	0.33
Semi-Dry FGD (LSD) (annual avg.)	0.08	0.37	0.08	0.36

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that the following existing SO2 emission rates are BART:

Comanche Unit 1: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). A 30-day rolling SO2 limit of 0.12 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology. A complete analysis that supports the BART determination for the Comanche facility can be found in Appendix C.

Particulate Matter BART Determination for Comanche - Units 1 and 2

Based on recent BACT determinations, the state has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent level of available control for PM/PM_{10}. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM_{10} as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for Comanche - Units 1 and 2

SNCR and SCR were determined to be technically feasible for reducing NOx emissions at Comanche Unit 1, and only SCR was determined feasible at Unit 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Comanche Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	445.6	$1,624,100	$3,644
SCR	770.4	$12,265,014	$15,290

Comanche Unit 2 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SCR	1,480	$14,650,885	$9,900

The energy and non-air quality impacts of the alternatives are as follows:

- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Comanche – Unit 1		Comanche – Unit 2	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (1-yr) using new LNBs	0.20		0.20	
SNCR (annual avg.)	0.10	0.11	Not Feasible	–
SCR (annual avg.)	0.07	0.14	0.07	0.17

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following existing NOx emission rates:

Comanche Unit 1: 0.20 lb/MMBtu (30-day rolling average)
0.15 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.20 lb/MMBtu (30-day rolling average)
0.15 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing low NOx burners. Although the other alternatives achieve better emissions reductions, the added expense of achieving lower limits through different controls were determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement (under 0.2 delta deciview) afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the State's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.10 dv for SNCR and 0.13 dv for SCR for Unit 1, and 0.17 dv for SCR for Unit 2). SNCR was found not to be technically feasible for Comanche Unit 2. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Comanche Units 1 and 2.

A complete analysis that supports the BART determination for PSCo's Comanche Units 1 and 2 can be found in Appendix C.

6.4.3.4 BART Determination for Tri-State Generation and Transmission Association's Craig Facility

Craig Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 BART Determination for Craig - Units 1 and 2

Wet FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following wet scrubber upgrades were considered for Craig Units 1 and 2, if technically feasible.

- *Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations in 2003-2004.
- *Installation of liquid distribution rings:* TriState determined that installation of perforated trays, described below, accomplished the same objective.
- *Installation of perforated trays:* Upgrades during 2003-2004 included installation of a perforated plate tray in each scrubber module.
- *Use of organic acid additives:* Organic acid additives were considered but not selected for the following reasons:
    1. Dibasic Acid (DBA) has not been tested at the very low inlet SO_2 concentrations seen at Craig Units 1 and 2.
    2. DBA could cause changes in sulfite oxidation with impacts on SO_2 removal and solids settling and dewatering characteristics.

3. Installation of the perforated plate tray accomplished the same objective of increased SO_2 removal.

- *Improve or upgrade scrubber auxiliary equipment:* 2003-2004 upgrades included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:

1. Two vertical ball mills were installed for additional limestone processing capability for increased SO_2 removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high SO_2 removal rates.
2. Forced oxidation within the SO_2 removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
3. A ventilation system was installed for each reaction tank.
4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased SO_2 removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
7. Instrumentation and controls were modified to support all of the new equipment.

- *Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during 2003-2004. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, there are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 through the five-factor analysis and determined that a more stringent 30-day rolling SO_2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology based on current emissions and operations. The tighter emission limits are achievable without additional capital investment. An SO2 limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Craig – Unit 1		Craig – Unit 2	
	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.17		0.16	
Wet FGD	0.11	0.03	0.11	0.03
Wet FGD	0.07	0.05	0.07	0.05

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 1: 0.11 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The 30-day rolling SO2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

Particulate Matter BART Determination for Craig - Units 1 and 2

The Division has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for $PM/PM_{10.}$ The state assumes that the BART emission limit can be achieved through the operation of the existing pulse jet fabric filter baghouses.

NOx BART Determination for Craig - Units 1 and 2

Potential modifications to the ULNBs, neural network systems, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$3,797,000	$4,877
SCR	3,855	$25,036,709	$6,445

Craig Unit 2 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	806	$3,797,000	$4,712
SCR	3,975	$25,036,709	$6,299

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, and hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Craig – Unit 1		Craig – Unit 2	
	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.35		0.35	
SNCR	0.24	0.31	0.23	0.31
SCR	0.07	1.01	0.07	0.98

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART Alternative determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1: 0.27 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.27 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of SNCR. For the BART emission limits at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented above.

- Unit 1: $4,877 per ton NOx removed; 0.31 deciview of improvement
- Unit 2: $4,712 per ton NOx removed; 0.31 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements, leads the state to this determination. To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Although emission limits associated with SCR achieve better emissions reductions, the cost-effectiveness of SCR for this BART determination was determined to be excessive and above the cost guidance criteria presented above. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs.

Per Section 308(e)(2) of EPA's Regional Haze Rule, as an alternative to BART (or "BART alternative") it was proposed and the state agreed to a more stringent NOx emissions control plan for these BART units that consists of emission limits assumed to be associated with the operation of SNCR for Unit 1 and the operation of SCR for Unit 2. These NOx emission rates are as follows:

Craig Unit 1: 0.28 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.08 lb/MMBtu (30-day rolling average)

Unit 1's 0.28 lb/MMBtu NOx emission rate equates to a 14% control and a NOx reduction of 727 tons per year, which is slightly less than the 15% control and a NOx reduction of 779 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.

Unit 2's 0.08 lb/MMBtu NOx emission rate equates to a 74% control and a NOx reduction of 3,975 tons per year, which is much greater than the 15% control and a NOx reduction of 806 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.

The total NOx emission reduction resulting from the BART determination is 1,585 tons per year (779 + 806 = 1,585 tons per year). The total NOx emission reduction resulting from the BART Alternative is 4,702 tons per year (727 + 3,975 = 4,702 tons per year). Given the far greater emission reduction achieved by the BART Alternative when compared to the BART determinations for the individual units, the state determines, in accordance with the federal Regional Haze regulations, that the BART Alternative emission rates are appropriate for Craig Units 1 and 2 as providing greater reasonable progress than the application of BART as set forth in the federal BART Alternative regulation.

The state also evaluated the NOx emission reduction associated with both units (Craig 1 & 2) in contrast to the existing NOx rates, presumptive BART NOx rate, source-by-source determination, and the final RH determination to determine the total NOx reduction benefit. In the below table, the existing NOx emissions from both units is 10,562 tons/year which is much lower than the existing presumptive BART emissions of 14,849 tons/year. The source-by-source BART determination resulted in NOx emissions of 8,978 tons/year which is well above the 5,860 tons/year in NOx emissions calculated to result from application of the BART Alternative. These tons/year calculations provide an emissions based comparison to demonstrate that the Craig BART Alternative provides greater reasonable progress than, and is superior to, source by source BART for these units. The table below is illustrative for demonstration purposes only. The tons per year projections provide an emission based comparison and are not enforceable requirements.

NOx Analysis	Units	Craig 1	Craig 2	Total
Annual Average Heat Input*	*[MMBtu]*	36,933,572	39,214,982	
Annual Average NOx Rate*	*[lb/MMBtu]*	0.28	0.27	
Annual Average NOx Emissions*	*[tons/year]*	5,190.3	5,371.6	10,562
Presumptive NOx Rate	*[lb/MMBtu]*	0.39	0.39	
Presumptive NOx Emissions	*[tons/year]*	7,202.1	7,646.9	14,849
Source-by-Source Determination	*[lb/MMBtu]*	0.27	0.27	
Source-by-Source Determination	*[tons/year]*	4,411.8	4,565.9	8,978
Final Regional Haze Determination	*[lb/MMBtu]*	0.28	0.08	
Final Regional Haze Determination	*[tons/year]*	4,463.7	1,396.6	5,860

** Data from CAMD used for period (2006-2007)*

Based on the above analysis and demonstration, the BART Alternative (final RH determination) achieves more NOx emissions reductions, which are well below the source-by-source BART determinations for each unit. Consequently, the BART Alternative will result in more visibility improvement at nearby Class I areas, and the state adopts this BART Alternative as appropriate to comply with the Regional Haze rule for these units. The state notes that this BART Alternative is not a trading program per Section 308(e)(2) and provisions associated with trading are not applicable.

Under EPA's Alternative to BART rule (40 CFR § 51.308(e)(2)), a state must show that the alternative measure or alternative program achieves greater reasonable progress than would be achieved through the installation and operation of BART. The demonstration addresses these requirements, as follows. (A complete description of these federal requirements is presented in section 6.4.3.7 below.)

1) *51.308(e)(2)(i)(A)* A listing of all BART-eligible sources can be found in Table 6-3 above.
2) *51.308(e)(2)(i)(B)* The two BART-eligible sources are Craig Units 1 and 2.
3) *51.308(e)(2)(i)(C)* The BART determinations presented herein describe the control information and the projected total NOx reduction of 1,585 tons per year for source-by-source BART.
4) *51.308(e)(2)(i)(D)* The BART Alternative achieves a projected NOx reduction of 4,702 tons per year.
5) *51.308(e)(2)(i)(E)* The BART Alternative achieves more than 3,100 tons of projected NOx reduction per year over what would be achieved by the installation of BART.
6) *51.308(e)(2)(iii)* The Craig BART Alternative will be implemented as expeditiously as practicable but no later than five years after EPA's approval of this BART Alternative, as required by Regulation No. 3 Part F. The regulation requires that a compliance schedule be developed by the source and submitted to the state within six months from EPA's approval. The compliance and

monitoring provisions of the BART Alternative have also been incorporated into Regulation No. 3, Part F.

7) *51.308(e)(2)(iv)* The emission reductions associated with the Craig BART Alternative have not been used for other SIP purposes, thus they are surplus.

8) *51.308(e)(2)(v)* The state is not proposing a geographic enhancement for reasonably attributable impairment.

9) *51.308(e)(2)(vi)* Since Colorado is not using a trading program for the Craig BART Alternative, this section does not apply.

10) *51.308(e)(3)* There are only two units at the same facility under the Craig BART Alternative and thus there is no change in the distribution of emissions than under BART, and, as stated above, the alternative measure results in greater emission reductions than case-by-case BART. Therefore the Craig BART Alternative is deemed to achieve greater reasonable progress.

11) *51.308(e)(3)(i)* Since the Craig BART Alternative includes only two units at the same facility, the state has determined that visibility does not decline in any Class I area due to the Craig BART Alternative when compared to case-by-case BART.

12) *51.308(e)(3)(ii)* Because the Craig BART Alternative has been demonstrated to achieve more emission reductions than would occur through case-by-case BART, the state determines that there will be an overall improvement in visibility over all affected Class I areas.

13) *51.308(e)(4)* Colorado is not participating in the CAIR program and cannot rely on this program for the Craig BART Alternative.

14) The state acknowledges that the core requirements will otherwise apply as set forth in the Regional Haze Rule.

15) *51.308(e)(6)* No Colorado BART sources have applied for an exemption from BART.

A complete analysis that supports the BART determination and BART Alternative for Craig Station Units 1 and 2, including substantial cost information for NOx controls, can be found in Appendix C.

6.4.3.5 BART Determination for Public Service Company's Hayden Station

Hayden Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. Public Service Company (PSCo) submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8, 2007. In response to a Division request, PSCo submitted additional information on May 25, 2010.

SO2 BART Determination for Hayden - Units 1 and 2

Semi-Dry FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades were considered for Hayden Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Hayden's dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Hayden, the use of performance additives on the scrubbers would not be expected to increase the SO_2 removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes SO_2 removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO_2. Since NO_2 is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO_2 removal rates, such as those experienced at Hayden. This side effect is unacceptable in a region with numerous Class I areas in close proximity to the source. There are no known acceptable reagents without this side effect that would allow additional SO_2 removal in the dry scrubbing systems present at Hayden Station.
- *Increase the pulverization level of sorbent* – PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system -* The supplier offers no upgrade in atomizer design to improve SO_2 removal at Hayden. However, an additional scrubber module could be added along with spare parts and maintenance personnel in order to meet a lower emission limit. This option is technically feasible.
- *Additional equipment and maintenance* - Hayden Units 1 and 2 can achieve a lower 30-day average emission rate limit than the 2008 State-adopted BART emission limit of 0.16 lbs/MMBtu by purchasing additional spare atomizer parts and increasing annual operating and maintenance through increased labor and reagent requirements. This emissions limit is 0.13 lbs/MMBtu, which is the current rolling 90-day limit.

The additional scrubber module, and additional spare atomizer parts with additional operation and maintenance were determined to be technically feasible for reducing SO2 emissions from Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Hayden Unit 1 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Semi-Dry FGD Upgrade – Additional Equipment and Maintenance	61	$141,150	$2,317
Additional Scrubber Module	488	$4,142,538	$8,490

Hayden Unit 2 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Semi-Dry FGD Upgrade – Additional Equipment and Maintenance	39	$141,150	$3,626
Additional Scrubber Module	589	$4,808,896	$8,164

The additional scrubber module option was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement (less than 0.1 deciview) that would result from this upgrade.

There are no energy and non-air quality impact associated with the remaining semi-dry FGD upgrade alternative (additional equipment and maintenance).

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Hayden – Unit 1		Hayden – Unit 2	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.34		0.40	
Existing Semi-Dry FGD (LSD) (annual avg.)	0.16	0.09	0.16	0.18
Semi-Dry FGD Upgrade (annual avg.)	0.13	0.10	0.13	0.21
Additional Scrubber Module (annual avg.)	0.07	0.14	0.07	0.26

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Hayden Unit 1: 0.13 lb/MMBtu (30-day rolling average)

Hayden Unit 2: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The state evaluated the option of tightening the emission limit for Hayden Units 1 and 2 and determined that a more stringent 30-day rolling SO2 limit of 0.13 lbs/MMBtu represents an appropriate level of emissions control for semi-dry FGD control technology. The tighter emission rate for both units is achievable with a negligible investment and the facility operator has offered to undertake these actions to allow for refinement of the emissions rate appropriate for this technology at this source despite the lack of appreciable modeled visibility improvement, and the state accepts this.

Particulate Matter BART Determination for Hayden - Units 1 and 2

Based on recent BACT determinations, the state has determined that the existing Unit 1 and Unit 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent level of available control for PM/PM_{10}. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM_{10} as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for Hayden - Units 1 and 2

LNB upgrades, SNCR and SCR were determined to be technically feasible for reducing NOx emissions at Hayden Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Hayden Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
LNB	1,391	$572,010	$411
SNCR	1,391	$1,353,500	$973
SCR	3,120	$10,560,612	$3,385

Hayden Unit 2 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
LNB	1,303	$992,729	$762
SNCR	1,610	$1,893,258	$1,176
SCR	3,032	$12,321,491	$4,064

The energy and non-air quality impacts of the alternatives are as follows:

- LNB – not significant

- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Hayden – Unit 1		Hayden – Unit 2	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.61		0.37	
LNB (annual avg.)	0.26	0.69	0.21	0.40
SNCR (annual avg.)	0.26	0.69	0.18	0.48
SCR (annual avg.)	0.07	1.12	0.06	0.85

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Hayden Unit 1: 0.08 lb/MMBtu (30-day rolling average)

Hayden Unit 2: 0.07 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of selective catalytic reduction (SCR). For these emission limits, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented above.

- Unit 1: $3,385 per ton NOx removed; 1.12 deciview of improvement
- Unit 2: $4,064 per ton NOx removed; 0.85 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements leads the state to this determination. The NOx emission limits of 0.08 lb/MMBtu (30-day rolling average) for Unit 1; and 0.07 lb/MMBtu (30-day rolling average) for Unit 2; are technically feasible and have been determined to be BART for Hayden Units 1 and 2.

A complete analysis that supports the BART determination for PSCo's Hayden Units 1 and 2 can be found in Appendix C.

6.4.3.6 BART Determination for Colorado Springs Utilities' Martin Drake Plant

Colorado Springs Utilities' Boilers 5, 6, and 7 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. The combined emissions of these boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, all three boilers are subject-to-BART. Initial air dispersion modeling performed by the Division demonstrated that the Martin Drake Plant contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Colorado Springs Utilities (CSU) submitted a BART Analysis to the Division on August 1, 2006 with updated cost information submitted on March 29, 2007. CSU also provided information in its "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 as well as additional information upon the Division's request on February 21, 2010, March 21, 2010, May 10, 2010, May 28, 2010, June 2, 2010, and June 15, 2010.

SO2 BART Determination for Martin Drake - Units 5, 6 and 7

Dry sorbent injection (DSI) was determined to be feasible for all units and dry FGD were determined to be technically feasible for reducing SO2 emissions from Units 6, and 7. These options were considered as potential BART level controls by the Division. Lime or limestone-based wet FGD system is also technically feasible but was determined to be not reasonable due to adverse non-air quality impacts. Drake is conducting a trial on a new wet FGD system design (NeuStream-S) that uses much less water along with a smaller operational footprint that may provide, if successfully demonstrated, a reasonable alternative to traditional wet FGD systems.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Drake Unit 5 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI	762	$1,340,663	$1,760

Drake Unit 6 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI	1,671	$2,910,287	$1,741
Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average)	2,284	$6,186,854	$2,709
Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average)	2,368	$6,647,835	$2,808
Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average)	2,507	$7,452,788	$2,973

Drake Unit 7 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI	2,657	$3,723,826	$1,405
Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average)	3,632	$8,216,863	$2,263
Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average)	3,764	$8,829,321	$2,345
Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average)	3,986	$9,898,382	$2,483

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only
- Dry FGD – less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Drake – Unit 5		Drake – Unit 6		Drake – Unit 7	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.94		1.00		0.99	
DSI (annual avg.)	0.25	0.12	0.33	0.18	0.33	0.29
Dry FGD (LSD) (annual avg.)	Not feasible		0.12	0.24	0.12	0.39
Dry FGD (LSD) (annual avg.)	Not feasible		0.07	0.26	0.07	0.41

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART for Unit 5 is the following SO2 emission rate:

Drake Unit 5: 0.26 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limit can be achieved through the installation and operation of dry sorbent injection. Other alternatives are not feasible.

- Unit 5: $1,760 per ton SO2 removed; 0.12 deciview of improvement

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART for Unit 6 and Unit 7 is the following SO2 emission rates:

Drake Unit 6: 0.13 lb/MMBtu (30-day rolling average)

Drake Unit 7: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of lime spray dryers (LSD). A lower emissions rate for Units 6 and 7 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.02 delta deciview for both units respectively).

These emission rates for Units 6 and 7 provide 85% SO2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 6: $2,808 per ton SO2 removed; 0.24 deciview of improvement
- Unit 7: $2,345 per ton SO2 removed; 0.39 deciview of improvement

Particulate Matter BART Determination for Martin Drake - Units 5, 6 and 7

The state determines that the existing regulatory emissions limit of 0.03 lb/MMBtu (PM/PM10) for the three units represent the most stringent control options. The units are exceeding a PM control efficiency of 95%, and the emission limits are BART for PM/PM_{10}. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for Martin Drake - Units 5, 6 and 7

Ultra low NOx burners (ULNB), ULNB including OFA, SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Drake Units 5, 6 and 7.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Drake Unit 5 - NO_x Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Overfire air (OFA)	154	$141,844	$923
Ultra-low NOx burners (ULNBs)	200	$147,000	$736
ULNBs + OFA	215	$288,844	$1,342
Selective Non-Catalytic Reduction (SNCR)	231	$1,011,324	$4,387
ULNB/SCR layered approach	626	$4,467,000	$7,133
Selective Catalytic Reduction (SCR)	626	$4,580,000	$7,314

Drake Unit 6 - NOx Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Overfire air (OFA)	283	$104,951	$371
Selective Non-Catalytic Reduction (SNCR)	424	$1,208,302	$2,851
Ultra-low NOx burners (ULNBs)	452	$232,800	$515
ULNBs + OFA	509	$337,751	$664
ULNB/SCR layered approach	1,175	$6,182,800	$5,260
Selective Catalytic Reduction (SCR)	1,175	$6,340,000	$5,395

Drake Unit 7 - NOx Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Overfire air (OFA)	416	$75,217	$181
Ultra-low NOx burners (ULNBs)	583	$386,000	$662
Selective Non-Catalytic Reduction (SNCR)	624	$2,018,575	$3,233
ULNBs + OFA	749	$461,217	$616
ULNB/SCR layered approach	1,709	$8,196,000	$4,797
Selective Catalytic Reduction (SCR)	1,709	$8,510,000	$4,981

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB – not significant
- ULNB – not significant
- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Drake – Unit 5		Drake – Unit 6		Drake – Unit 7	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.62		0.83		0.71	
OFA (annual avg.)	0.30	0.07	0.33	0.18	0.31	0.22
ULNB (annual avg.)	0.28	0.08	0.28	0.193	0.28	0.24
ULNB + OFA (annual avg.)	0.27	0.08	0.27	0.20	0.25	0.26
SNCR (annual avg.)	0.27	0.08	0.29	0.19	0.28	0.24
ULNB + SCR	0.07	0.12	0.07	0.27	0.07	0.37
SCR (annual avg.)	0.07	0.12	0.07	0.27	0.07	0.37

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOX BART for Units 5, 6 and 7 is the following NOx emission rates:

Drake Units 5 and 6: 0.31 lb/MMBtu (30-day rolling average)

Drake Unit 7: 0.29 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of ultra low-NOx burners (including over-fire air).

- Unit 5: $1,342 per ton NOx removed
- Unit 6: $664 per ton NOx removed
- Unit 7: $616 per ton NOx removed

The extremely low dollars per ton control costs leads the state to selecting this emission rate for each of the Drake units. SNCR is not selected as that technology provides an equivalent emissions rate, similar level of NOx reduction coupled with equivalent visibility improvement at a much higher cost per ton of pollutant removed along with potential energy and non-air quality impacts. SCR is not selected as the cost/effectiveness ratios for Units 5 and 6 are too high and the visibility improvement at all units do not meet the criteria guidance described above (*e.g.* less than 0.50 Δdv)

For Drake Units 5 and 6, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.04 dv for SCR on Unit 5 and 0.07 dv for SCR on Unit 6). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Units 5 and 6.

For Drake Unit 7, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.11 dv for SCR). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Unit 7.

A complete analysis that supports the BART determination for CSU's Martin Drake Units 5, 6 and 7 can be found in Appendix C.

6.4.3.7 BART Determination for Public Service Company's Cherokee Unit 4, Valmont Unit 5 and the Pawnee Station as a BART Alternative, which Includes Reasonable Progress Determinations for Arapahoe Units 3 and 4 and Cherokee Units 1, 2 and 3

Background

Section 308(e)(2) of EPA's Regional Haze Rule allows a state to approve a BART alternative:

> *A State may opt to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. Such an emissions trading program or other alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. For all such emission trading programs or other alternative measures, the State must submit an implementation plan containing the following plan elements and include documentation for all required analyses: (i) A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the State and covered by the alternative program. This demonstration must be based on the following: (A) A list of all BART-eligible sources within the State. (B) A list of all BART-eligible sources and all BART source categories covered by the alternative program. The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program, but each BART-eligible source in the State must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with section 302(c) or paragraph (e)(1) of this section, or otherwise addressed under paragraphs (e)(1) or (e)(4) of this section.*

The PSCo BART Alternative Program (““PSCo BART Alternative”) was proposed by Public Service Company of Colorado (PSCo). The PSCo BART Alternative is not a trading program and does not include any complete source categories, although all facilities in the PSCo BART Alternative are electric generating units. The PSCo BART Alternative is based on reductions achieved as a result of a combination of unit shutdowns and the application of emissions controls planned as part of the Colorado HB 10-1365, the “Clean Air – Clean Jobs Act” (§ 40-3.2-201 C.R.S., *et. seq*.). The PSCo BART Alternative includes ten units at four facilities. The facilities included in the PSCo Alternative and the proposed controls are listed below.

Table 6-5: Actions and Dates under the PSCo Alternative

Facility	Unit	Action or Control	Effective Date
Arapahoe	Unit 3	Shutdown	12/31/2013
	Unit 4	Operation on Natural Gas only (peaking unit)	12/31/2014
Cherokee	Unit 1	Shutdown	No later than 7/1/2012
	Unit 2	Shutdown	12/31/2011
	Unit 3	Shutdown	No later than 12/31/2016
	Unit 4	Operation on Natural Gas only	12/31/2017
Valmont		Shutdown	12/31/2017
Pawnee		SCR & LSD	12/31/2014

The state in evaluating the PSCo Alternative followed the EPA July 6, 2005, BART guidelines and the EPA October 13, 2006, regulation referred to as Provisions Governing Alternative to Source-Specific BART Determinations (71Fed.Reg. 60612-60634 (10/13/2006); 40 CFR § 51.308(e)(2), “Alternative to BART rule”). Under the Alternative to BART rule, a state must show that the alternative measure or alternative program achieves greater reasonable progress than would be achieved through the installation and operation of BART. The demonstration must include five elements:

1) A list of all BART-eligible sources within the state;
2) A list of all BART-eligible sources and source categories covered by the alternative program;
3) An analysis of the best system of continuous emission control technology available and the associated reductions;
4) An analysis of the projected emissions reductions achievable through the alternative measure; and
5) A determination that the alternative measure achieves greater reasonable progress than would be achieved through the installation of BART.

The PSCo Alternative includes both BART and non-BART sources. The non-BART sources are older than the BART timeframe, and in effect will all be controlled and reduce their NOx and SO2 emissions as a result of enforceable facility retirement dates and, for one unit, operating only on natural gas as a “peaking” unit. The BART sources, Cherokee 4, Pawnee and Valmont, will all be either controlled within the first planning period or shutdown with enforceable facility retirement dates.

The state's alternative program satisfies the requirements of 40 CFR § 51.308, as further described in the preambles to the BART guidelines and the Alternative to BART rule. The state's analysis must include:

> *An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.*

40 CFR § 51.308(e)(2)(i)(C).

Colorado's alternative program was designed to meet a requirement other than BART; namely, Colorado's HB 10-1365. The express purpose of the legislation leading to the alternative program being proposed is:

> THE GENERAL ASSEMBLY HEREBY FINDS, DETERMINES, AND DECLARES THAT THE FEDERAL "CLEAN AIR ACT", 42 U.S.C. SEC. 7401 ET SEQ., WILL LIKELY REQUIRE REDUCTIONS IN EMISSIONS FROM COAL-FIRED POWER PLANTS OPERATED BY RATE-REGULATED UTILITIES IN COLORADO. A COORDINATED PLAN OF EMISSION REDUCTIONS FROM THESE COAL-FIRED POWER PLANTS WILL ENABLE COLORADO RATE-REGULATED UTILITIES TO MEET THE REQUIREMENTS OF THE FEDERAL ACT AND PROTECT PUBLIC HEALTH AND THE ENVIRONMENT AT A LOWER COST THAN A PIECEMEAL APPROACH. A COORDINATED PLAN OF REDUCTION OF EMISSIONS FOR COLORADO'S RATE-REGULATED UTILITIES WILL ALSO RESULT IN REDUCTIONS IN MANY AIR POLLUTANTS AND PROMOTE THE USE OF NATURAL GAS AND OTHER LOW-EMITTING RESOURCES TO MEET COLORADO'S ELECTRICITY NEEDS, WHICH WILL IN TURN PROMOTE DEVELOPMENT OF COLORADO'S ECONOMY AND INDUSTRY.

§ 40-3.2-202, C.R.S. Similarly, Colorado's Clean Air – Clean Jobs Act further specifies that it is intended to address both current and reasonably foreseeable future requirements of the federal Clean Air Act. *See,* § 40-3.2-204, C.R.S.

PSCo BART Alternative measure for the subject coal-fired electric generating units is thus designed to meet the requirements of the regional haze rule, including BART, but also to address requirements beyond BART. This includes, for example, a revised national standard for ozone to be promulgated in 2011, other revised or to be revised national ambient air quality standards, or federal sector-specific regulations for hazardous air pollutants, among other federal regulatory requirements. Accordingly, the state will determine whether the PSCo BART Alternative represents the best system of continuous emission control technology and associated emission reductions for the sources included in the alternative. In the preamble to the Alternative to BART rule, EPA discusses whether the option exists for states to use simplifying assumptions in determining the BART benchmark, or whether states must establish the BART benchmark through a source-by-source BART analysis. EPA states:

> [T]here is no need to develop a precise estimate of the emissions reductions that could be achieved by BART in order simply to compare two programs. As EPA did in the CAIR, States should have the ability to develop a BART benchmark based on simplifying assumptions as to what the most-stringent BART is likely to achieve. The regulations finalized today therefore provide that where an emission trading program has been designed to meet a requirement other than BART, including the reasonable progress requirement, the State may establish a BART benchmark based on an analysis that includes simplifying assumptions about BART control levels for sources within a source category.

71 Fed. Reg. 60612, 60618 (October 13, 2006). EPA has thus determined that source-by source BART is not required when it is not necessary where a state has determined that greater reasonable progress can be achieved by an alternative means. *See also,* 70 Fed. Reg. 39104, 39137 (July 6, 2005). Thus, there is no need for states to conduct an extensive source-by-source BART assessment, and to then also go through the additional, resource intensive steps of developing an alternative program to BART. *See,* 71 Fed. Reg. at 60617.

Colorado has looked at several options to establish the BART benchmark. EPA establishes some criteria for the BART benchmark in the Alternative to BART rule, where the agency discusses simplifying assumptions.

> In today's final rule, the regulations make clear that, with one exception, States must follow the approach for making BART determinations under section 51.308(e)(1) in establishing a BART benchmark. This includes the requirement for States to use the BART guidelines in making BART determinations for EGUs at power plants of a certain size. As discussed above, the one exception to this general approach is where the alternative program has been designed to meet requirements other than BART; in this case, States are not required to make BART determinations under § 51.308(e)(1) and may use simplifying assumptions in establishing a BART benchmark based on an analysis of what BART is likely to be for similar types of sources within a source category. Under either approach to establishing a BART benchmark, we believe that the presumptions for EGUs in the BART guidelines should be used for comparison to a trading program or other alternative measure, unless the State determines that such presumptions are not appropriate for particular EGUs.

71 Fed. Reg. at 60619 (October 13, 2006). *See also, id*. at 60615 ("Where a trading program or other similar alternative program has been designed primarily to meet a Federal or State requirement other than BART, the State can use a more simplified approach to demonstrating that the alternative program will make greater reasonable progress than BART. Such an approach may be appropriate where the State believes the alternative program is clearly superior to BART and a detailed BART analysis is not

necessary to assure that the alternative program will result in greater reasonable progress than BART.").

The PSCo BART Alternative includes only EGUs and, based on EPA's Alternative to BART rule, one option available is a comparison to the presumptive limits in the BART guidelines. *Id*. The presumptive limits represent a reasonable estimate of stringent case BART, particularly when developing a BART benchmark to assess an alternative program, because they are applied equally to EGU's of varying size and distance from Class I areas, and with varying impacts on visibility. *Id.* Because not all of the sources in the PSCo BART Alternative are BART sources, the state also considered other benchmarks that might be appropriate. For example, as part of the BART and reasonable progress analysis, the state has established guidelines for NOx based on control technology costs and visibility improvements. The state's analysis substantiates that the PSCo BART Alternative provides greater reasonable progress than would have been achieved without the alternative.

Analysis Under 40 CFR Part 51, § 308(e)

(2)(i)(A) A list of all Bart-eligible sources within the State.

A listing of all BART-eligible sources can be found in Table 6-3 in this Chapter 6 of the Regional Haze State Implementation Plan.

(2)(i)(B) A list of all BART-eligible sources and all BART source categories covered by the alternative program.

The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program. However, each BART-eligible source in the State covered by the PSCo BART Alternative in this case must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with section 302(c) or section 308(e)(1), or otherwise be addressed under section 308(e)(1) or (e)(4). The BART sources covered by the PSCo BART Alternative are shown in Table 6-6.

Table 6-6: Sources Included Within the PSCo Alternative

Facility	Unit	Action or Control
Arapahoe	Unit 3	Shutdown
	Unit 4	Operation on natural gas only
Cherokee	Unit 1	Shutdown
	Unit 2	Shutdown
	Unit 3	Shutdown
	Unit 4 (BART-eligible)	Operation on natural gas only
	New nat. gas-fired EGU	BACT where netting does not apply
Valmont	(BART-eligible)	Shutdown
Pawnee	(BART-eligible)	SCR & LSD

(2)(i)(C) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.

The PSCo BART Alternative includes the emission reductions achieved through Colorado HB 10-1365 (§ 40-3.2-201 C.R.S., *et seq*.). The PSCo BART Alternative was developed to address requirements other than BART, including to support the attainment of federal ambient air quality standards, to meet other federal requirements that can affect electric generating units, and improve air quality on the Front Range of Colorado. Since the PSCo BART Alternative was designed to address requirements other than BART, it meets the EPA SIP provision noted above that allows the state to determine the base case BART emissions using simplifying assumptions. This approach is discussed in EPA's Alternative to BART Rule. *See,* 71 Fed. Reg. at 60612 (October 13, 2006). Colorado has estimated base case BART emissions assuming that the plants included in the PSCo BART Alternative emit at the presumptive levels established by EPA for electric generating units of greater than 750 MW.[18] The emissions resulting from the PSCo BART Alternative are then compared to the analysis of base case BART emissions to indicate the degree of emissions reduction improvement provided by the PSCo BART Alternative.

(2)(i)(D) An analysis of the projected emissions reductions achievable through the trading program or other alternative measure.

The emission reductions achievable through PSCo's Alternative include the reductions associated with the combination of shutdowns and retrofit controls established under PSCo's emissions reduction plan, endorsed by the state Public Utilities Commission pursuant to HB 10-1365, and codified and made enforceable by the elements reflected in this State Implementation Plan. The following emissions reductions provided by the PSCo BART Alternative are reflected in Tables 6-7 and 6-8, below. With respect to SO2 emissions, the PSCo BART Alternative will reduce SO2 emissions from these units by 21,493 tons per

[18] None of the BART units included in this Alternative are larger than 750MW, thus the presumptive emissions standards for electric generating units set forth in EPA's BART guidelines are not mandatory for these units. *See, e.g.,* 70 Fed. Reg. at 39108. The non-BART units included in this Alternative are also not subject to the presumptive emissions standards as a mandatory element of Regional Haze. While not required as a matter of regulation the presumptive limits are employed in this instance solely for demonstrative and comparative purposes.

year in the first planning period (2010 to 2018). With respect to NOx emissions, the PSCo BART Alternative will reduce NOx emissions from these units by 15,994 tons per year in the first planning period (2010 to 2018).

(2)(i)(E) A determination under paragraph (e)(3) of this section or otherwise based on the clear weight of evidence that the trading program or other alternative measure achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources.

The PSCo BART Alternative has been evaluated according to the emissions based test discussed in EPA's Alternative to BART Rule. This is explained in further detail below, and demonstrates that for both SO2 and NOx, due to a combination of substantial retirements of coal-fired units and controls on other coal-fired units, the PSCo BART Alternative provides greater reasonable progress than would be afforded under BART at the covered sources.

(2)(ii) [Reserved]

(2)(iii) A requirement that all necessary emission reductions take place during the period of the first long-term strategy for regional haze. To meet this requirement, the State must provide a detailed description of the emissions trading program or other alternative measure, including schedules for implementation, the emission reductions required by the program, all necessary administrative and technical procedures for implementing the program, rules for accounting and monitoring emissions, and procedures for enforcement.

The PSCo BART Alternative for these electric generating units will be implemented during the first long-term strategy period, by December 31, 2017. The PSCo BART Alternative as set forth in this SIP establishes an expeditious implementation schedule for the coordinated shutdown of, and installation of retrofit emissions controls on the covered coal-fired electric generating units. As reflected in Table 6-12, emission limits for SO2 and NOx at Pawnee, operation on natural gas at Cherokee Unit 4, operation on natural gas at Arapahoe Unit 4 as a peaking unit only, and shutdowns at Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont, will all occur during the first planning period. Some of the NOx emissions reductions will be reserved, and are not used in this alternative measure demonstration and not reflected in the emissions reductions in this SIP, to allow for natural gas replacement power at Cherokee and future "netting" or "offsets". The compliance and monitoring provisions of the PSCo BART Alternative have been incorporated into Regulation No. 3, Part F. Compliance will be determined through the use of continuous emission monitors for those facilities that are not shutdown. Enforceability of the shutdown of coal-fired units under the PSCo BART Alternative is reflected in this State Implementation Plan, as well as in Regulation No. 3, Part F. Colorado will also amend the relevant permits to include enforceable shutdown dates.

(2)(iv) A demonstration that the emission reductions resulting from the emissions trading program or other alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.

The emission controls associated with the PSCo BART Alternative have not been used for other SIP purposes, thus they are surplus. The reductions from the shutdown of Arapahoe units 1 and 2 were used in an earlier PM SIP demonstration and are not included in this analysis.

(2)(v) At the State's option, a provision that the emissions trading program or other alternative measure may include a geographic enhancement to the program to address the requirement under §51.302(c) related to BART for reasonably attributable impairment from the pollutants covered under the emissions trading program or other alternative measure.

The Division is not proposing a geographic enhancement for reasonably attributable impairment.

(2)(vi) For plans that include an emissions trading program that establishes a cap on total annual emissions of SO2 or NOx from sources subject to the program, requires the owners and operators of sources to hold allowances or authorizations to emit equal to emissions, and allows the owners and operators of sources and other entities to purchase, sell, and transfer allowances, the following elements are required concerning the emissions covered by the cap:

Since Colorado is not using a trading program for the PSCo BART Alternative, this section does not apply. Electric generating units subject to this alternative have unit-specific compliance requirements reflected in this SIP and in Reg. No. 3, Part F.

(3) A State which opts under 40 CFR 51.308(e)(2) to implement an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART may satisfy the final step of the demonstration required by that section as follows: If the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emission reductions, then the alternative measure may be deemed to achieve greater reasonable progress. If the distribution of emissions is significantly different, the State must conduct dispersion modeling to determine differences in visibility between BART and the trading program for each impacted Class I area, for the worst and best 20 percent of days. The modeling would demonstrate "greater reasonable progress" if both of the following two criteria are met:

The Division has determined that the distribution of emissions under the PSCo BART Alternative is not substantially different than under BART, and the alternative measure results in greater emission reductions than case-by-case BART. The PSCo BART Alternative includes three BART units at four different facilities, all of which are in or immediately adjacent to the 8-Hour Ozone Non-Attainment Area in the Front Range of Colorado. Like the other three facilities, the fourth is the Arapahoe facility and it is central to the non-attainment area, and is only 17 kilometers from the Cherokee facility.

(3)(i) Visibility does not decline in any Class I area, and

Since the Metro Denver BART eligible sources are included in the PSCo BART Alternative along with other non–BART sources in the area, and the overall visibility-impairing pollutants from these units decrease substantially, the Division has determined that visibility does not decline in any Class I area in relation to this PSCo BART Alternative.

(3)(ii) There is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas.

The PSCo Alternative has been demonstrated to achieve more emission reductions than would occur through case-by-case BART. The reasons why the alternative provides greater reductions include:

a) Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont (BART eligible unit), will be shutdown during the first planning period.

b) Arapahoe Unit 4 will operate on natural gas as a peaking unit.

c) Cherokee Unit 4 (BART eligible unit) will operate on natural gas only.

d) Pawnee Unit 1(BART eligible unit) will install and operate an LSD to control SO_2 emissions and SCR to control NO_x emissions in 2014.

(4) A State that chooses to meet the emission reduction requirements of the Clean Air Interstate Rule (CAIR) by participating in one or more of EPA's CAIR trading programs

Colorado is not participating in the CAIR program.

(5) After a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the requirements of paragraph (d) of this section in the same manner as other sources.

The state acknowledges that the core requirements will otherwise apply as set forth in the Regional Haze Rule.

(6) Any BART-eligible facility subject to the requirement under paragraph (e) of this section to install, operate, and maintain BART may apply to the Administrator for an exemption from that requirement. An application for an exemption will be subject to the requirements of §51.303(a)(2)–(h).

No Colorado BART sources have applied for an exemption from BART.

Technical Analysis of the PSCo Alternative Emissions Reductions with Respect to the Section 308(e) Alternative Measure Demonstration

The following technical analysis of emissions reductions that result from the PSCo BART Alternative more fully demonstrates that the proposed alternative achieves greater reasonable progress than the installation of BART, as allowed under EPA's regional haze regulations. EPA's Regional Haze Rule requires that BART- eligible sources either install BART as determined for each source on a case-by-case basis, or install controls as required by a BART Alternative. EPA's BART guidance (70 Fed. Reg. 39104, July 6, 2005) and EPA's regulation on BART Alternatives (71 Fed. Reg. 60612, October 13, 2006) both provide guidance on how to evaluate whether a BART Alternative proposal achieves greater reasonable progress under the regulation. This determination can be made based on an emissions comparison or through a modeling analysis if the state determines that is appropriate. If the geographic distribution of emissions reductions from the programs is expected to be similar, the comparison can be made based on emissions alone. 70 Fed. Reg. at 39136; 71 Fed. Reg. at 60620. Because all the sources included in the PSCo BART Alternative are located in the same air shed and within a 100 mile area, the Division has determined that the BART eligible sources in the PSCo BART Alternative are in the same geographic region (namely, in the Denver Metro Area and also in or immediately adjacent to the existing 8-Hour Ozone Non-Attainment Area) for purposes of regional haze. Thus an emissions demonstration is appropriate and modeling is not warranted for an alternative measure demonstration.

EPA's BART guidance does not specify a quantity of emission reductions an alternative must exceed to satisfy the "achieves greater reasonable progress" criteria. In its BART guidance, EPA provides an emission-based demonstration of how EPA determined the Clean Air Interstate Rule (CAIR) to be better than case-by-case BART on individual sources. In that instance, EPA demonstrated that more tons of emission reductions would result from the CAIR rule than with source-by-source BART. *See, e.g.,* 70 Fed. Reg. at 39141. Similarly, the state has utilized the emission-based method to evaluate the PSCo BART Alternative. The state has determined that the PSCo BART Alternative achieves greater reasonable progress by evaluating the future emissions from the electric generating units under the operating scenarios reflected in the PSCo BART Alternative, and for demonstration purposes compared those emissions with the same units using the standard established by EPA of 95 percent removal or 0.15 lb/MMBtu for SO2 or a lb/MMBtu for NOx based on boiler and coal type. *See* 71 Fed. Reg. at 60619 ("States establishing a BART benchmark based on simplifying assumptions as to the most stringent BART for EGUs may rely on the presumptions, as EPA did in the CAIR rule.").

As previously discussed, the PSCo Alternative is based on a combination of emissions control retrofits and shutdowns resulting from Colorado HB 10-1365 and the PUC's actions. The PSCo BART Alternative includes Pawnee, Arapahoe Units 3 and 4, Valmont Unit 5, and Cherokee Units 1-4. Pawnee, Cherokee Unit 4 and Valmont Unit 5 are the only BART eligible units. The sources involved in the PSCo BART Alternative are either BART eligible sources or sources that precede the BART timeframe. For demonstration purposes, the emissions from the entire group of electric generating units in the PSCo BART Alternative were compared to the emissions from the units if the presumptive levels were applied, as allowed under EPA's regulation. Table 6-7 compares the tons of SO2 that would be emitted under the PSCo BART Alternative to the number of tons of SO2 that would be emitted by the same units if the standard of 0.15 lb SO2/MMBtu were applied. The 0.15 lb/MMBtu standard comes from the 70 Fed. Reg. 39132 (7/6/2005) in which EPA establishes "BART limits of 95 percent SO2 removal, or an emission rate of 0.15 lb SO2/MMBtu". The MMBtu used for the analysis is an average of the actual MMBtu reported by the units to the Clean Air Markets Division for 2006, 2007 and 2008. For units that will be shutdown or operated on natural gas (Arapahoe unit 4) under the PSCo BART Alternative an emissions factor of 0.0006 lb SO2/MMBtu was used for the alternative.

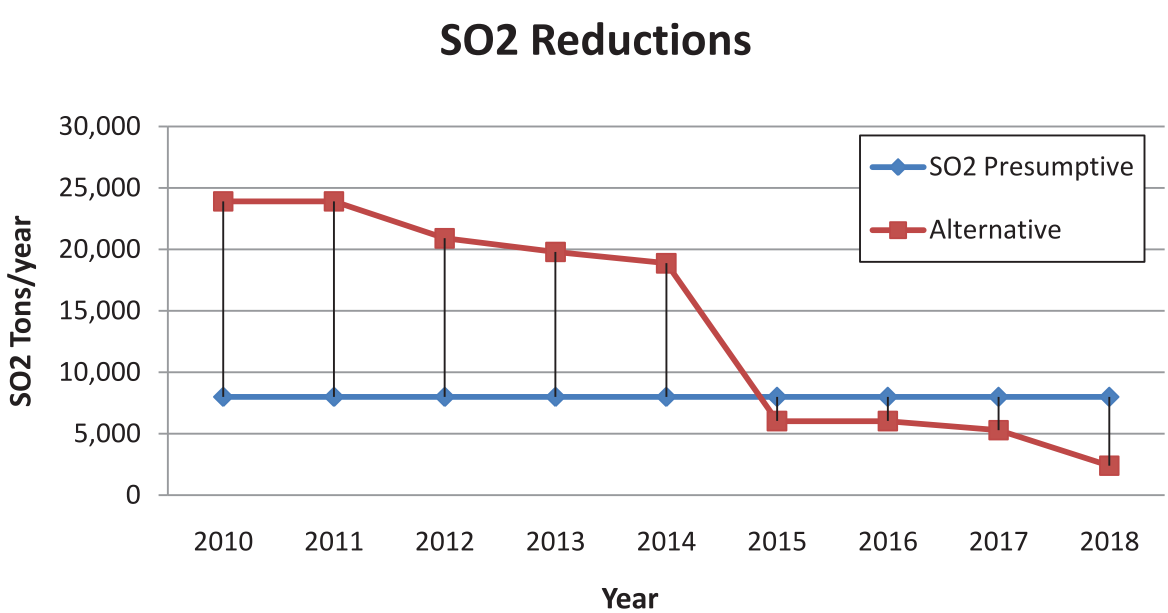
Table 6-7: SO2 Reductions Beyond Presumptive BART for PSCo Alternative

Facility	MMBtu Average 2006 to 2008	SO2 TPY Average 2006 to 2008	SO2 TPY at 0.15 lb/MMBtu Presumptive	SO2 TPY under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe					
Unit 3	4,380,121	924.97	328.51	0.00	100.00%
Unit 4	8,545,791	1,764.70	640.93	1.28[19]	99.8%
Cherokee					
Unit 1	8,311,352	2,220.80	623.35	0.00	100.00%
Unit 2	5,586,021	1,888.37	418.95	0.00	100.00%
Unit 3	8,159,889	743.00	611.99	0.00	100.00%
Unit 4	26,047,648	2,135.43	1,953.57	7.81	99.6 %
Valmont	13,722,507	758.47	1,029.19	0.00	100.00%
Pawnee	40,093,753	13,472.07	3,007.03	2,405.63	20.00%
Total	114,847,083	23,908	8,614	2,415	71.97%

The comparison with the standard of 0.15 lb SO2/MMBtu shows that the PSCo BART Alternative provides 72% lower SO2 emissions.

Figure 6-1 provides a year by year comparison of the PSCo BART Alternative to the 0.15 lb SO2/MMBtu standard for this planning period.

Figure 6-1: SO2 reductions beyond presumptive BART for PSCo Alternative



[19] Emission factor of 0.0006 lb SO2/MMBtu and 50% capacity factor.

A similar analysis was completed for NOx emissions. Table 6-8 compares the PSCo BART Alternative to a standard based on NOx limits established by EPA in 70 Fed. Reg. 39135 (7/6/2005). EPA provides a NOx lb/MMBtu level based on the boiler type and the coal type burned. The PSCo BART Alternative reflects 600 tpy of NOx emitted from Arapahoe 4 operating on natural gas as a "peaking" unit, 300 tpy of NOx reserved for "netting" or "offsets" from the Arapahoe facility, and 500 tpy of NOx reserved for "netting" or "offsets" from the Cherokee facility.

Table 6-8: NOx Reductions Beyond Presumptive BART for PSCo Alternative

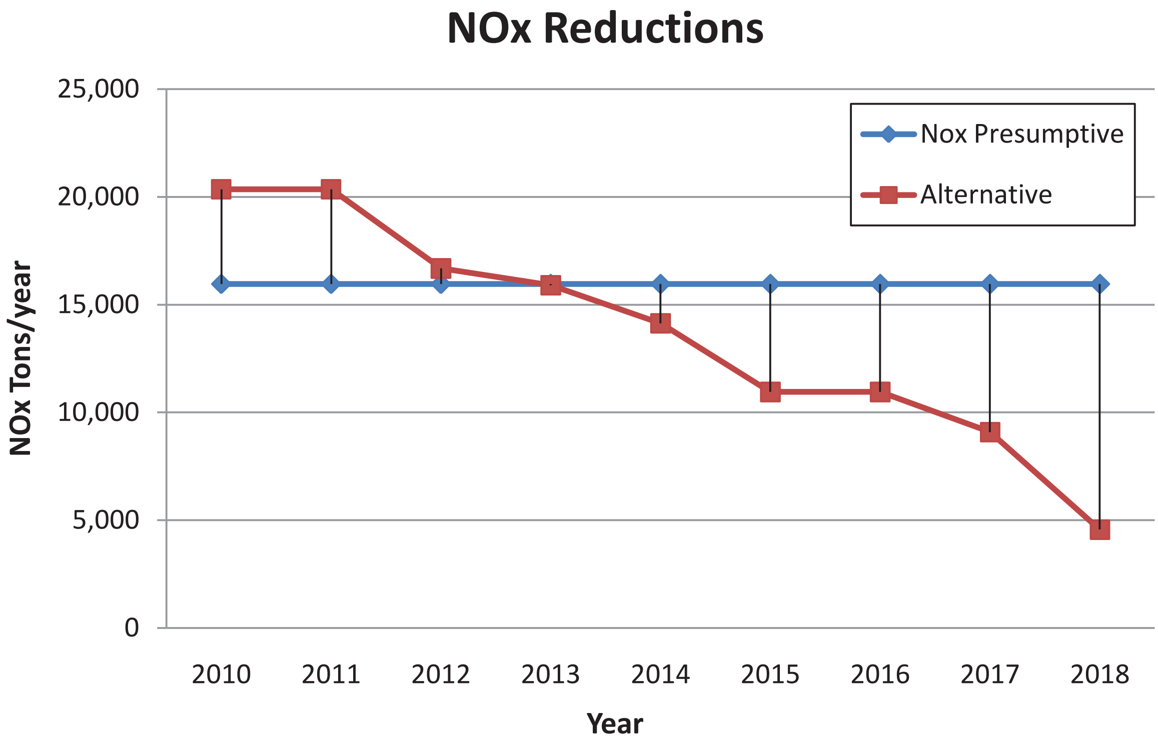
Facility	MMBtu Average 2006 to 2008	NOx TPY Average 2006 to 2008	NOx lb/MMBtu Standard	TPY NOx at Standard	TPY NOx Under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe						
Unit 3	4,380,121	1,770.47	0.23	503.71	0.00	100.00%
Unit 4	8,545,791	1,147.67	0.23	982.77	900.00[20]	8.42%
Cherokee						
Unit 1	8,311,352	1,556.23	0.39	1,620.71	0.00	100.00%
Unit 2	5,586,021	2,895.20	0.39	1,089.27	0.00	100.00%
Unit 3	8,159,889	1,865.50	0.39	1,591.18	0.00	100.00%
Unit 4	26,047,648	4,274.00	0.28	3,646.67	2,062.86[21]	43.43%
Valmont	13,722,507	2,313.73	0.28	1,921.15	0.00	100.00%
Pawnee	40,093,753	4,537.73	0.23	4,610.78	1,403.28	69.57%
Total	114,847,083	20,361		15,966	4,366	72.65%

Figure 6-2 illustrates the year by year reductions achieved by the PSCo BART Alternative as compared to the standard derived from the EPA standard based on the configuration of each unit and the coal type burned by the unit in the PSCo BART Alternative.

[20] 600 tpy NOx from operation of Arapahoe 4 on natural gas as a "peaking" unit and 300 tpy NOx reserved for "netting" and "offsets" for additional natural gas generation. The 300 tpy NOx is associated with unit 4 for illustrative purposes, but may be associated with either unit.

[21] Cherokee 4 operating on natural gas at 0.12 lb NOx/mmBTU and 500tpy NOx reserved for "netting" or "offsets". The 500 tpy NOx is associated with unit 4 for illustrative purposes, but may be associated with any combination of the units.

Figure 6-2: NOx Reductions Beyond Presumptive BART for PSCo Alternative



The PSCo BART Alternative provides a reduction of 15,994 tons per year of NOx and 21,493 tons per year of SO2 from the baseline (average of 2006-2008 actuals) (89% and 77% reduction, respectively). These SO2 and NOx reductions provide significantly greater reductions as compared to the application of the standard set forth in 70 Fed. Reg. 39132-39135 (7/6/2005) applied all the units in the PSCo BART Alternative. The PSCo BART Alternative provides a 71% improvement in NOx reductions (See Table 6-8) over the presumptive levels, and a 72% improvement in SO2 reductions (See Table 6-7) over the presumptive levels. This is a significantly higher reduction than would have been achieved through the application of the presumptive limits. The state's alternative program is thus "clearly superior" to source-specific BART. *See* 71 Fed. Reg. at 60615. It provides not only for further emission reductions at units, but reflects the closure of numerous units, and thus the complete elimination of emissions from those units. Because these measures will provide greater emission reductions and will occur within the first planning period, the state has determined that they also satisfy reasonable progress for these sources. In this regard, Colorado has reasonably concluded that any control requirements imposed in the BART context also satisfy the RP related requirements in the first planning period. *See* U.S. EPA, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," p. 4-2 (June 2007).

Supplemental Technical Analysis Supporting the Alternative measure demonstration for the PSCo Alternative

In addition to the foregoing demonstration that the PSCo BART Alternative satisfies the requirements of 40 CFR 51.308(e)(2) for an approvable alternative to EPA's BART regulation, the state undertook and provides the following additional technical analyses to support its determination that the PSCo BART Alternative demonstrates greater reasonable progress than the installation of BART on subject to BART units.

Colorado also evaluated the NOx reductions of the alternative program based on the criteria established by the state for BART and reasonable progress for NOx reductions. As part of its five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

For the PSCo BART Alternative sources included in the PSCo BART Alternative, SCR costs (where technically feasible) are greater than $5,000 per ton of NOx removed or the visibility improvement from SCR is less than 0.50 Δdv. See analysis in appendix C. Under the state's criteria this would eliminate SCR from further consideration as a control alternative for BART and reasonable progress. Thus, for demonstration purposes the state has compared the PSCo BART Alternative with the emission reductions achievable by SNCR. The division used study of SNCR on coal fired boilers in the size range of those in the PSCO BART Alternative. The study showed that the SNCR tested achieved a 35% reduction in NOx with less than 2ppm NH_3 slip and 54% reduction with a 10ppm NH_4 slip.[22] Because of the high ammonia slip at the higher range of NOx removal the division determined that 50% removal was appropriate for this comparison. Thus, for comparative purposes for the PSCo BART Alternative, the state will assume that SNCR is applied at a level of NOx reduction, of 50%, to assess performance of presumed SNCR on these units as against the PSCo BART Alternative for NOx.[23] Table 6-9 provides a comparison of the costs for SCR and SNCR as provided by PSCo, SNCR at a 50% reduction (calculated from an average of NOx actual from 2006-2008 as reported to the Clean Air Markets Division) and the PSCo BART Alternative.

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[22] Environmental Controls Conference, Pittsburgh, PA (5/16/2006 to 5/18/2006)

[23] This level of NOx control efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that SNCR on these particular electric generating units could, in fact, achieve this level of NOx reduction performance from application of SNCR.

Table 6-9: NOx reductions beyond state criteria for PSCo Alternative

Facility	SCR $/ton	SNCR $/ton	SNCR TPY at 50%[24]	PSCo Alternative TPY	% Reduction from SNCR at 50% Control
Arapahoe					
Unit 3			885.23	0	100.00%
Unit 4			573.83	900[25]	-56.84%
Cherokee					
Unit 1	N/A	$8,737	778.12	0	100.00%
Unit 2	N/A	$3,963	1,447.60	0	100.00%
Unit 3	$10,134	$3,485	932.75	0	100.00%
Unit 4	$6,252	$2,625	2,137.00	2,062[26]	3.47%
Valmont	$8,647	$3,328	1,156.87	0	100.00%
Pawnee	$4,371	$3,082	2,268.87	1,403	38.15%
Total			10,180	4,366	57.11%

The PSCo BART Alternative results in 55% more reduction in NOx than the assumed installation of SNCR at all units covered by the PSCo BART Alternative. A similar analysis was not completed for SO2 because the state did not look at SO2 controls for reasonable progress as all sources were already controlled.

For both SO2 and NOx the state also evaluated the PSCo BART Alternative against a source by source analysis. For SO2 the state has done source specific analyses for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 95% control level assumption to the uncontrolled emissions from those sources. The 95% was taken both from current operations and from uncontrolled emissions calculated using AP-42.[27] The analysis demonstrates that the alternative proposed is better than the source by source analysis by more than 52% as shown in Table 6-10. Figure 6-3 shows the reductions

[24] Fifty percent reduction was taken from an average of 2006-2008 actual NOx emissions as reported to the Clean Air Markets Division.

[25] 600 tpy NOx from operation of Arapahoe 4 on natural gas as a “peaking” unit and 300 tpy NOx reserved for “netting” and “offsets” for additional natural gas generation.

[26] Cherokee 4 operating on natural gas at 0.12 lb NOx/MMBtu and 500 tpy NOx reserved for “netting” or “offsets”.

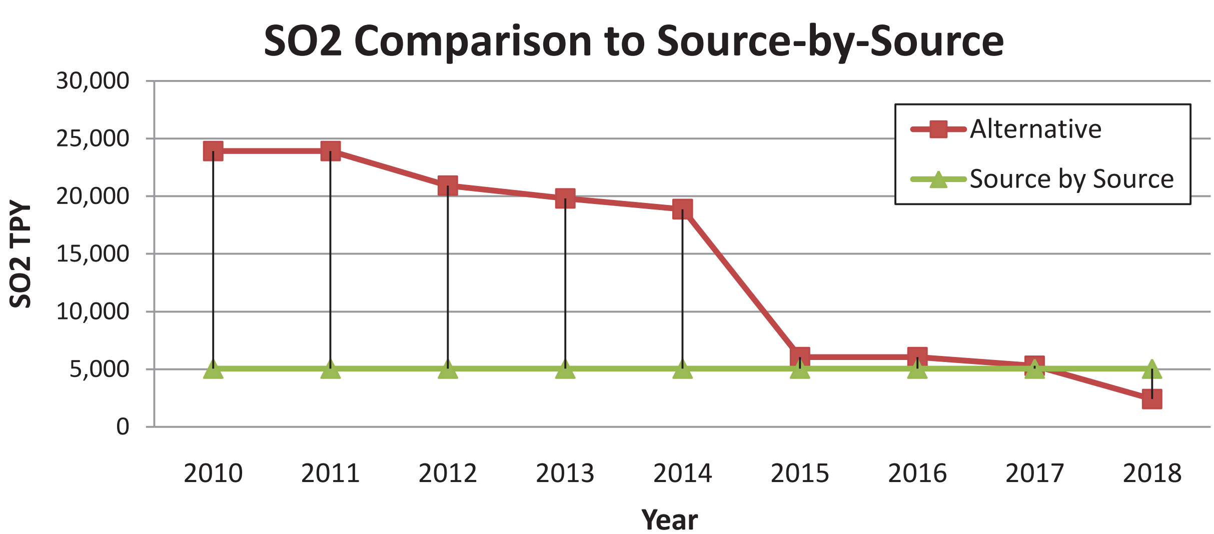
[27] This level of SO2 reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units burning low-sulfur western coal, could, in fact, achieve this level of SO2 reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities. This is different from the other analyses provided in this document, and when employing a 95% reduction assumption for demonstration purposes for an alternative measure makes the starting point for the sources in the Alternative more similar to uncontrolled eastern sources, where a higher sulfur content coal is generally utilized, which is more relevant to an assumed 95% reduction of SO2.

from the PSCo BART Alternative as compared to the source by source evaluation on a year to year basis.

Table 6-10: SO2 Reductions Beyond Source-By-Source BART for PSCo Alternative

Facility	SO2 TPY from AP-42	Source-by-Source	SO2 TPY from PSCo Alternative	% Reduction Beyond Source-by-Source
Arapahoe				
Unit 3	1,076.53	53.82	0.00	100.00%
Unit 4	2,322.21	1.28	1.28	0.00%
Cherokee				
Unit 1	2,803.67	140.18	0.00	100.00%
Unit 2	2,662.17	133.10	0.00	100.00%
Unit 3	3,438.79	171.93	0.00	100.00%
Unit 4	9,779.27	1,953.57[28]	7.81	99.6%
Valmont	3,822.73	191.13	0.00	100.00%
Pawnee	8,342.36	2,405.62[29]	2,405.63	0.00%
Total	34,248	5,051	2,415	52.19%

Figure 6-3: SO2 Reductions Beyond Source-By-Source BART for PSCo Alternative



[28] The Cherokee Unit 4 BART evaluation concluded that a 0.15 lb SO2/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

[29] The Pawnee BART evaluation concluded that a 0.12 lb SO2/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

For NOx the state looked at a source by source analysis for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 90% control level assumption to the sources. The 90% was taken from emissions calculated using AP-42.[30] The source by source analysis considered the operation of Arapahoe Unit 4 with natural gas as a peaking unit and retaining 300 tpy of NOx for future netting or offsets from Arapahoe, the operation of Cherokee Unit 4 on natural gas at 0.12 lb/MMBTU and retaining 500 tpy of NOx from Cherokee for future netting, and control of Pawnee with SCR at 0.07 lb/MMBTU. The results of the comparison indicate that the alternative proposed is 49% better than the source by source analysis.

Table 6-11: NOx Reductions Beyond Source-By-Source BART for PSCo Alternative

Facility	NOx TPY from AP-42	Source-by-Source	NOx TPY from PSCo Alternative	% Reduction Beyond Source-by-Source
Arapahoe				
Unit 3	2,149.15	214.91	0.00	100.00%
Unit 4	4,636.00	600	900.00[31]	-50.00%
Cherokee				
Unit 1	3,596.54	359.65	0.00	100.00%
Unit 2	3,415.03	341.50	0.00	100.00%
Unit 3	4,411.28	441.12	0.00	100.00%
Unit 4	7,878.04	2,735.00[32]	2,062.86[33]	24.58%
Valmont	2,061.04	206.10	0.00	100.00%
Pawnee	7,945.11	3,608.43	1,403.28	61.11%
Total	36,092	8,507	4,366	48.67%

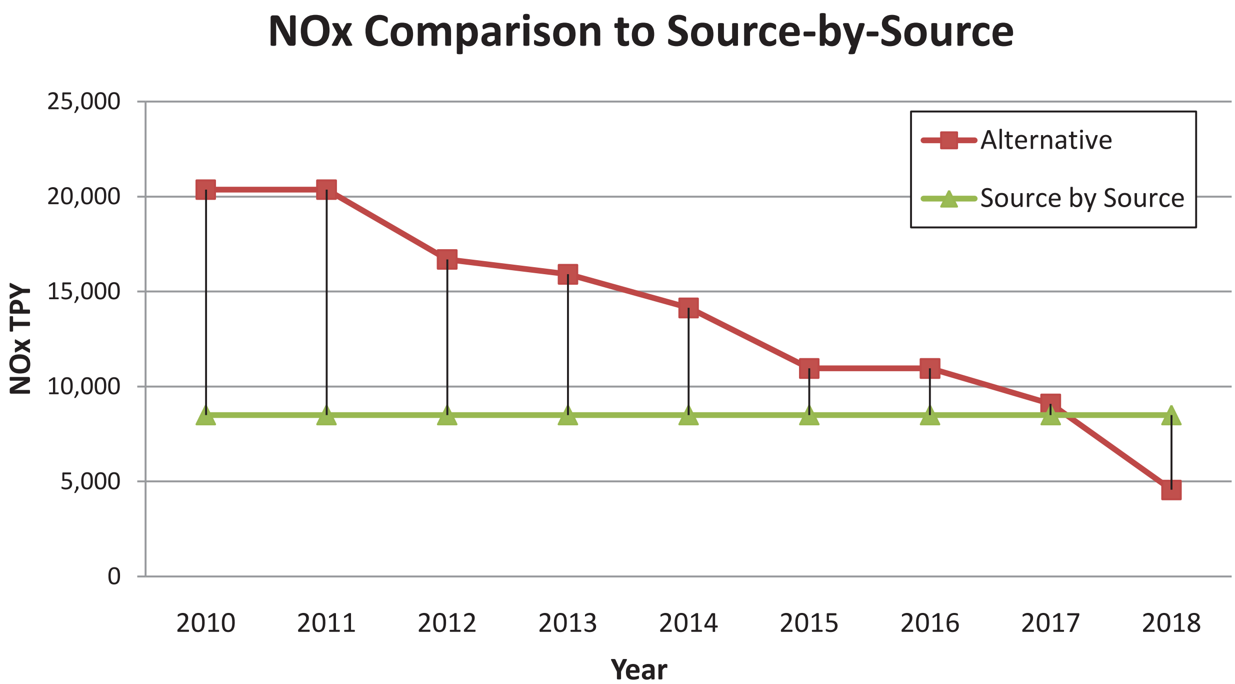
[30] This level of NOx reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units, could, in fact, achieve this level of NOx reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities.

[31] Natural gas operation as a peaking unit limited to 600 tpy with 300 tpy NOx reserved for offsets or netting for additional natural gas generation.

[32] Coal fired operation with SNCR at 0.21 lb NOx/MMBtu.

[33] Natural gas operation at 0.12 lb NOx/MMBtu with 500 tpy NOx reserved for offsets or netting.

Figure 6-4: NOx Reductions Beyond Source-By-Source BART for PSCo Alternative



Conclusion

Under EPA regional haze regulations, Colorado has utilized an emission based comparison to demonstrate that that the PSCo BART Alternative provides greater reasonable progress than, and is clearly superior to, source by source BART. Although not necessary, as a means of further supporting its demonstration, the state has utilized other methodologies to demonstrate that the PSCo BART Alternative achieves greater reasonable progress than BART or individual reasonable progress requirements. The PSCo BART Alternative will result in early and significant reductions of visibility impairing pollutants.

Table 6-12: PSCo Alternative Emissions Limits[34, 35, 36]

Unit	NOx Control Type	NOx Emission Limit	SO2 Control Type	SO2 Emission Limit	Particulate Type And Limit
Cherokee Unit 1	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012
Cherokee Unit 2	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011
Cherokee Unit 3	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016
Cherokee Unit 4	Natural Gas Operation	0.12 lb/MMBtu (30-day rolling average) by 12/31/2017	Natural Gas Operation 12/31/2017	7.81 tpy (12 month rolling average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas Operation 12/31/2017
Valmont Unit 5	Shutdown 12/31/2017	0	Shutdown 12/31/2017	0	Shutdown 12/31/2017
Pawnee Unit 1	SCR**	0.07 lb/MMBtu (30-day rolling average) by 12/31/2014	Lime Spray Dryer**	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	Fabric Filter Baghouse* 0.03 lbs/MMBtu
Arapahoe Unit 3	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Arapahoe Unit 4	Natural Gas Operation	600 tpy (12 month rolling average) by 12/31/2014	Natural Gas operation 12/31/2014	1.28 tpy (12 month rolling average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas operation 12/31/2014

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the above table is not a requirement.

34 Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.

35 500 tpy NOx will be reserved from Cherokee Station for netting or offsets.

36 300 tpy NOx will be reserved from Arapahoe Station for netting or offsets for additional natural gas generation.

Chapter 7 Visibility Modeling and Apportionment

Modeling results and technical analyses indicate that Colorado sources contribute to visibility degradation at Class I areas. The modeling also shows out-of-state sources have the greatest impact on regional haze in Colorado. As such, this Plan anticipates local and regional solutions so that Colorado's 12 Class I areas make progress towards the 2018 and 2064 visibility goals.

7.1 Overview of the Community Multi-Scale Air Quality (CMAQ) Model

The Regional Modeling Center (RMC) Air Quality Modeling group is responsible the Regional Haze modeling for the WRAP. The RMC is located at the University of California - Riverside in the College of Engineering Center for Environmental Research and Technology.

The RMC modeling analysis is based on a model domain comprising the continental United States using the Community Multi-Scale Air Quality (CMAQ) model. The EPA developed the CMAQ modeling system in the late 1990s. CMAQ was designed as a "one atmosphere" modeling system to encompass modeling of multiple pollutants and issues, including ozone, PM, visibility, and air toxics. This is in contrast to many earlier air quality models that focused on single-pollutant issues (e.g., ozone modeling by the Urban Airshed Model). CMAQ is an Eulerian model - that is, it is a grid-based model in which the frame of reference is a fixed, three-dimensional (3-D) grid with uniformly sized horizontal grid cells and variable vertical layer thicknesses. The key science processes included in CMAQ are emissions, advection and dispersion, photochemical transformation, aerosol thermodynamics and phase transfer, aqueous chemistry, and wet and dry deposition of trace species.

A detailed summary of the CMAQ modeling for each Class I area is included in Section 6 of the Technical Support Document.

7.2 CMAQ Modeling Results for 2018

Figure 7-1 lists the 2018 Uniform Progress (UP) for each class I area along with the visibility modeling forecasts for 2018. These modeling results were released in 2006 by the WRAP and are preliminary; new modeling results with the latest emission estimates and control measure benefits are anticipated mid- to late 2007, and additional modeling is scheduled to be performed in 2008 and 2009. The results of this modeling will be utilized in defining (RPGs) for all 12 Colorado Class I areas by the year 2010 as described in Chapter 9.

As indicated by the 2006 modeling, reasonable progress for each Class I area falls short of meeting 2018 uniform progress for the 20% worst days, as indicated by the numbers in the blue highlighted box. Alternatively, all areas are forecast to maintain the best days in 2018.

More detailed information on the CMAQ modeling for a particular Class I area can be found in Section 6 of the Technical Support Document.

Figure 7-1 Summary of CMAQ Modeling Progress Towards 2018 UP

Colorado Mandatory Class I Federal Areas
Uniform Progress Summary in Haze Index Metric
Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	20% Worst Days					20% Best Days		
	Worst Days Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2018 URP delta from Baseline [dv]	2018 Modeling Projection [dv]	CMAQ Modeling % Towards 2018 URP	Best Days Baseline Condition [dv]	2018 CMAQ Modeling Results [dv]	2018 CMAQ Modeling Below Baseline?
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

7.3 Overview of Particulate Matter Source Apportionment Technology (PSAT) Modeling

The Regional Modeling Center (RMC) at the University of California – Riverside developed the PSAT algorithm in the Comprehensive Air quality Model with extensions (CAMx) model to assess source attribution. The PSAT analysis is used to attribute particle species, particularly sulfate and nitrate from a specific location within the Western Regional Air Partnership (WRAP) modeling domain. The PSAT algorithm applies nitrate-sulfate-ammonia chemistry to a system of tracers or “tags” to track the chemical transformations, transport and removal of emissions.

Each state or region (i.e. Mexico, Canada) is assigned a unique number that is used to tag the emissions from each 36-kilometer grid cell within the WRAP modeling domain. Due to time and computational limitations, only point, mobile, area and fire emissions were tagged.

The PSAT algorithm was also used, in a limited application (e.g. no state or regional attribution) due to resource constraints, to track natural and anthropogenic species of organic aerosols at each CIA. The organic aerosol tracer tracked both primary and secondary organic aerosols (POA & SOA). Appendix H includes more information on PSAT methodology.

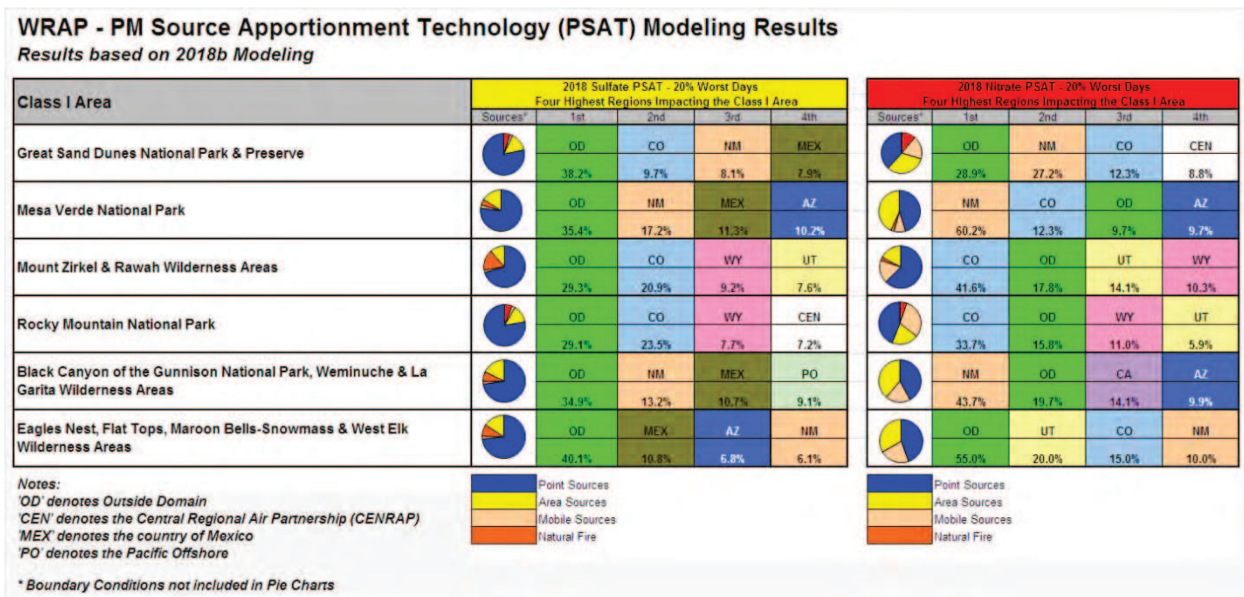
More detailed information on the PSAT modeling can be found in Section 7 of the Technical Support Document for each Class I area.

7.4 PSAT Modeling Results for 2018

Figure 7-2 provides the four highest source areas contributing sulfate and nitrate at each Class I area. As indicated, boundary conditions (BC) are the highest contributor to sulfate at all Colorado Class I areas. The boundary conditions represent the background concentrations of pollutants that enter the edge of the modeling domain. Depending on meteorology and the type of pollutant (particularly sulfate), these emissions can be transported great distances that can include regions such as Canada, Mexico, and the Pacific Ocean. Colorado appears to be a major contributor of particulate sulfate at those Class I areas near significant sources of SO2.

For nitrate, Colorado appears to be a major contributor at most of our Class I areas except for the Weminuche Wilderness, La Garita Wilderness and Black Canyon of Gunnison National Park. Although, boundary conditions also appear to be a major contributor of nitrate at all our Class I areas.

Figure 7-2 Summary of PSAT Modeling for 2018



WRAP - PM Source Apportionment Technology (PSAT) Modeling Results
Results based on 2018b Modeling

Class I Area	2018 Sulfate PSAT - 20% Worst Days, Four Highest Regions Impacting the Class I Area: 1st	2nd	3rd	4th	2018 Nitrate PSAT - 20% Worst Days, Four Highest Regions Impacting the Class I Area: 1st	2nd	3rd	4th
Great Sand Dunes National Park & Preserve	OD 38.2%	CO 9.7%	NM 8.1%	MEX 7.9%	OD 28.9%	NM 27.2%	CO 12.3%	CEN 8.8%
Mesa Verde National Park	OD 35.4%	NM 17.2%	MEX 11.3%	AZ 10.2%	NM 60.2%	CO 12.3%	OD 9.7%	AZ 9.7%
Mount Zirkel & Rawah Wilderness Areas	OD 29.3%	CO 20.9%	WY 9.2%	UT 7.6%	CO 41.6%	OD 17.8%	UT 14.1%	WY 10.3%
Rocky Mountain National Park	OD 29.1%	CO 23.5%	WY 7.7%	CEN 7.2%	CO 33.7%	OD 15.8%	WY 11.0%	UT 5.9%
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	OD 34.9%	NM 13.2%	MEX 10.7%	PO 9.1%	NM 43.7%	OD 19.7%	CA 14.1%	AZ 9.9%
Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas	OD 40.1%	MEX 10.8%	AZ 6.8%	NM 6.1%	OD 55.0%	UT 20.0%	CO 15.0%	NM 10.0%

Sources*: Point Sources, Area Sources, Mobile Sources, Natural Fire

Notes:
'OD' denotes Outside Domain
'CEN' denotes the Central Regional Air Partnership (CENRAP)
'MEX' denotes the country of Mexico
'PO' denotes the Pacific Offshore

** Boundary Conditions not included in Pie Charts*

Figure 7-3 identifies the change in the Colorado portion of particulate sulfate and nitrate concentrations, from 2002 to 2018 at each Class I area. For 2018, the PSAT modeling forecasts a reduction in the Colorado portion of sulfate at all Class I areas ranging from 25% to 33%. These particulate sulfate reductions are due to reductions from point and mobile source sulfur dioxide emissions (see Figure 5-1).

The 2018 forecasts for nitrate appear mixed with increases of 25% to 27% at the southwest Colorado Class I areas and nitrate reductions of 9% to 28% at all other areas. The increase in particulate nitrate in southwest Colorado is likely due to forecast increases in Colorado's and the region's NOx emissions from area sources and oil & gas development (see Figure 5-2). The projected particulate nitrate reductions at the remaining Class I areas are due to NOx reductions in mobile sources.

Figure 7-3 Colorado Share of Modeled Sulfate and Nitrate Changes for 2018

Change in Modeled Concentration for Colorado Share

Based PM Source Apportionment Technology (PSAT) Modeling Results (2018b)

Class I Area	Year	Total SO4 [ug/m3]	Colorado SO4 [ug/m3]	Colorado Share SO4	Colorado Sulfate Change	Total NO3 [ug/m3]	Colorado NO3 [ug/m3]	Colorado Share NO3	Colorado Nitrate Change
Great Sand Dunes National Park & Preserve	2002	0.440	0.057	13%		0.116	0.017	15%	
	2018	0.442	0.043	10%	-25%	0.114	0.014	12%	-18%
Mesa Verde National Park	2002	0.665	0.013	2%		0.249	0.026	10%	
	2018	0.644	0.009	1%	-31%	0.269	0.033	12%	+27%
Mount Zirkel & Rawah Wilderness Areas	2002	0.649	0.175	27%		0.214	0.085	40%	
	2018	0.621	0.130	21%	-26%	0.185	0.077	42%	-9%
Rocky Mountain National Park	2002	0.760	0.238	31%		0.339	0.128	38%	
	2018	0.677	0.159	23%	-33%	0.273	0.092	34%	-28%
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	2002	0.484	0.024	5%		0.080	0.004	5%	
	2018	0.484	0.018	4%	-25%	0.071	0.005	7%	+25%
Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas	2002	0.428	0.028	7%		0.020	0.004	20%	
	2018	0.424	0.021	5%	-25%	0.020	0.003	15%	-25%

Chapter 8 Reasonable Progress

8.1 Overview of Reasonable Progress Requirements

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals (expressed in deciviews) for each Class I area in Colorado that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. These reasonable progress goals (RPGs) are to provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

In establishing the RPGs, the state must consider four factors: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. As well, the state must include a demonstration showing how these factors were taken into consideration in selecting the goals.

In establishing RPGs, the state must estimate the 2018 uniform rate of progress (URP) for each Class I area. The state must consider the URP and the emission reductions needed to achieve URP for the period covered by the plan. If the state ultimately establishes a Reasonable Progress Goal that provides for a slower rate of visibility improvement than would be necessary to meet natural conditions by 2064, the state must demonstrate that the uniform rate is not reasonable and that the state's alternative goal is reasonable, based on an evaluation of the 4 factors. In addition, the state must provide to the public an assessment of the number of years it would take to achieve natural conditions if improvement continues at the rate selected by the state. The detailed discussion of Reasonable Progress Goals can be found in Chapter 9, "Long Term Strategy". The establishment of the pollutants for RP evaluations and the evaluation of significant sources for reasonable progress is presented below.

8.2 Visibility Impairing Pollutants Subject to Evaluation

The state conducted a detailed evaluation[37] of the six particulate pollutants; ammonium sulfate, ammonium nitrate, organic carbon (OC), elemental carbon (EC), fine soil and coarse mass (CM) (both of which are commonly known as particulate matter (PM)), contributing to visibility impairment at Colorado's 12 mandatory Class I federal areas, and determined that the first Regional Haze Plan RP evaluation should focus on significant point sources of SO2 (sulfate precursor), NOx (nitrate precursor) and PM emissions. Emission sources are best understood for these three visibility-impairing pollutants, and stationary, or "point" sources, dominate the emission inventories and apportionment modeling. This determination is based on the well documented point source emission inventories for SO2 and NOx, and the Regional Model performance for sulfate and nitrate was determined to be acceptable. Significant point source PM emissions are also evaluated because of the Q/d screening methodology (Q = total

[37] *Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas*, October 2, 2007. See the Technical support Document

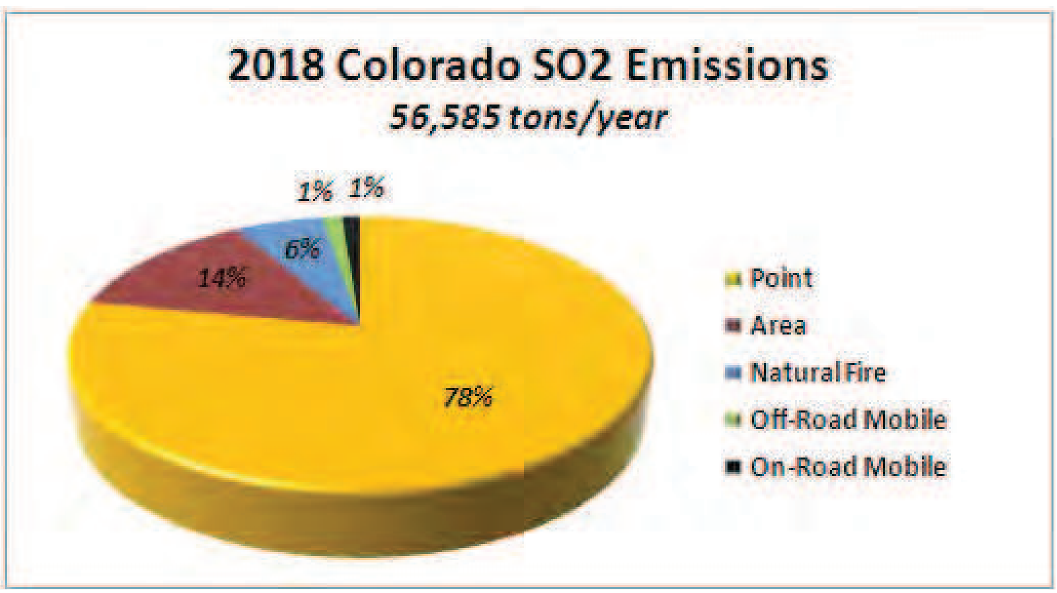
SO2, NOx and PM emissions; d = distance from the nearest Class I area, as further described in section 8.3), which includes PM emissions. PM emissions from other anthropogenic and natural sources are not being evaluated at this time.

Mobile and area sources were also identified as significant contributors to nitrates, and the RP evaluation of these two source categories is presented in section 8.2 above.

Generally, the sources of other visibility impairing pollutants, OC, EC, and PM, are not well documented because of emission inventory limitations associated with natural sources (predominantly wildfires), uncertainty of fugitive (windblown) emissions, and poor model performance for these constituents. Without a sound basis for making emission control determinations for sources that emit these three pollutants, Colorado determines that it is not reasonable in this planning period to recommend emission control measures; the State intends to address these pollutants and their emissions sources in future plan updates.

Figure 8-1 provides the statewide projected 2018 SO2 emissions, which reflects "on-the-books (OTB)" and "on-the-way (OTW)" emission control measures as of January 2009 (the latest year for a complete emissions inventory compiled by the Western Regional Air Partnership (WRAP)).

Figure 8-1: Relative Source Contributions to Colorado SO2 Emissions in 2018

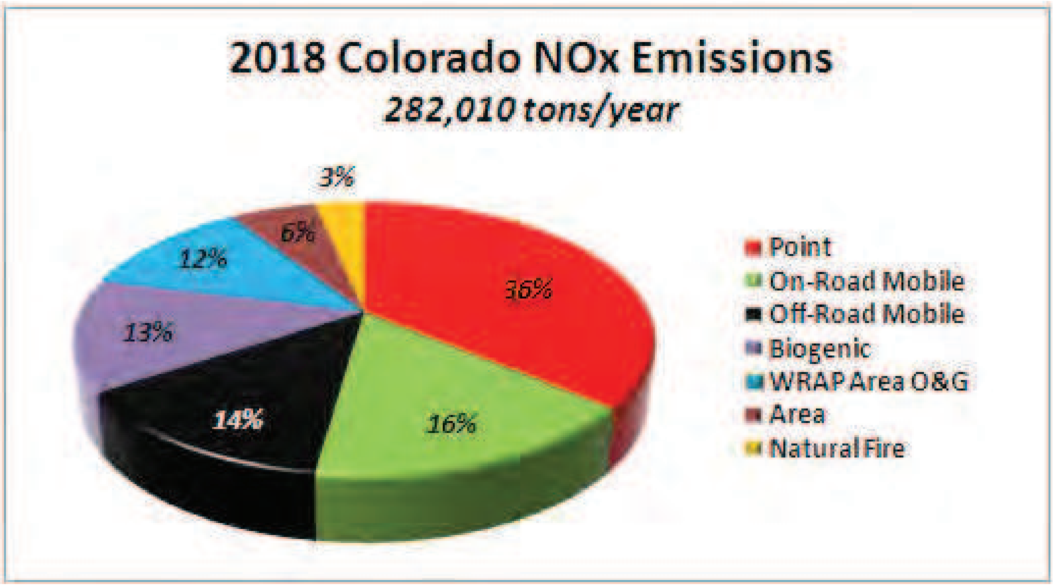


As indicated, 78% of total statewide SO2 emissions are from point sources – largely coal-fired boilers. Area source SO2 emissions (14%) are dominated by thousands of boilers and internal combustion engines statewide that burn distillate fuel. Depending on use and fuel grade, the maximum sulfur content of distillate fuel ranges between 500 ppm to 5000 ppm. SO2 emissions from natural fires are considered uncontrollable and vary from year-to-year depending on precipitation, fuel loading and lightning. Both off-road and on-road mobile sources are subject to federal ultra-low sulfur diesel (ULSD) fuel requirements that limit sulfur content to 15 ppm (0.0015 %) that was in widespread use after June 2010 for off-road mobile and June 2006 for on-road mobile.

The state has determined that point sources are the dominant source of emissions and, for this planning period, the only practical category to evaluate under reasonable progress for SO2.

Figure 8-2 provides the statewide projected 2018 NOx emissions, which reflects OTB and OTW emission control measures as of October 2009 (the latest year for a complete emissions inventory compiled by the WRAP).

Figure 8-2: Relative Source Contributions to Colorado NOx Emissions in 2018



Point sources comprise 36% of total NOx emissions that are mostly coal-fired external combustion boilers and natural gas-fired internal combustion engines (in oil and gas compression service). On-road and off-road mobile sources comprise 16% and 14% of statewide NOx emissions respectively. A portion of the on-road mobile source NOx emissions reflect some level of NOx control because of the Denver metro-area vehicle inspection program (IM-240). Both on/off road mobile also benefit from fleet turnover to cleaner vehicles resulting from more stringent federal emission standards. Because mobile exhaust emissions are primarily addressed, and will continue to be addressed, through federal programs, mobile sources will not be evaluated by Colorado for further RP control in this planning period. NOx emissions from biogenic activity and natural fire are considered uncontrollable and vary from year-to-year. Non-oil and gas area sources comprise about 6% of NOx emissions that involve thousands of combustion sources that are not practical to evaluate in this planning period.

The state has determined that large point sources are the dominant source of emissions and for this planning period are practical to evaluate under reasonable progress for NOx. Also, certain smaller point sources and area sources of NOx will also be evaluated under RP.

8.3 Evaluation of Smaller Point and Area Sources of NOx for Reasonable Progress

Oil and gas area source NOx emissions have been determined to significantly contribute to visibility impairment in Colorado's Class I areas. Because this source category is made up of numerous smaller sources, it is only practical to evaluate the category for RP control as a whole, unlike point sources where individual sources are evaluated separately. When reviewing O&G area sources, natural gas-fired heaters, and reciprocating internal combustion engines (RICE), are identified as the largest NOx emission sources. When reviewing point sources, natural gas-fired turbines were also identified as significant for review for RP.

8.3.1 Oil and Gas Heater Treaters

A heater-treater is a device used to remove contaminants from the natural gas at or near the well head before the gas is sent down the production line to a natural gas processing plant. It prevents the formation of ice and natural gas hydrates that may form under the high pressures associated with the gas well production process. These solids can plug the wellhead.

The latest 2018 emissions inventory for the state assumes approximately 23,000 tons of NOx per year from 26,000 natural gas heater-treaters in Colorado at an emissions level of 0.88 tpy NOx per gas well heater-treater.

Emissions control research and control application for this source category is not well developed and has focused primarily on methane reductions. Though there are some technically feasible control options, the costs of compliance and the control effectiveness cannot be confidently determined. While the cumulative emissions make this a significant source category, the state determines that, for this planning period, requiring the control of 26,000 individual sources less than one ton per year in size is not practical or reasonable for reasonable progress.

A detailed 4-factor analysis for heater treaters can be found in Appendix D.

8.3.2 Reciprocating Internal Combustion Engines

Power generated by large reciprocating internal combustion engines (RICE) is generally used to compress natural gas or to generate electricity in remote locations. The designation "large" refers to RICE that have an engine rating of at least 100 horsepower (hp) for the purpose of this reasonable progress analysis.

Stationary RICE produce power by combustion of fuel and are operated at various air-to-fuel ratios. If the stoichiometric ratio is used, the air and fuel are present at exactly the ratio to have complete combustion. RICE are operated with either fuel-rich ratios at or near stoichiometric, which are called rich-burn engines (RB), or air-rich ratios below stoichiometric, which are called lean-burn engines (LB). Undesirable emissions from RICE are primarily nitrogen oxides (NO_x; primarily nitric oxide and nitrogen dioxide), carbon monoxide (CO), and volatile organic compounds (VOCs). NO_x are formed by thermal oxidation of nitrogen from the air. CO and VOCs are formed from incomplete combustion. Rich-burn engines inherently have higher NOx emissions by design, and lean burn engines are designed to have relatively lower NOx emissions.

Colorado has undertaken regulatory initiatives to control NOx emissions from RICE, beginning in 2004. For the Denver metro area/North Front Range ozone control area, Regulation No. 7 was revised to require the installation of controls on new and existing rich burn and lean burn RICE larger than 500 hp by May 1, 2005. Controls for rich burn RICE are non-selective catalytic reduction (NSCR) and an air-to-fuel ratio controller, which effectively controls NOx (95%), CO and VOCs. Controls for lean burn RICE are oxidation catalyst reduction, which effectively control CO and VOCs. An exemption from control for lean burn RICE could be obtained upon demonstration that cost of emission control would exceed $5,000 per ton. Selective catalytic reduction was considered for the control of NOx from lean burn engines, but was dismissed due to the high cost/effectiveness at approximately $22,000/ton (see Appendix D for complete analysis). EPA approved this requirement as part of the Colorado SIP on August 19, 2005 (70 Fed. Reg. 48652 (8/19/05)).

In December 2008, Colorado proceeded to adopt into Regulation No. 7 similar provisions for all existing RICE over 500 hp throughout the state. By July 1, 2010 all existing engines in Colorado, had to install controls as described in the paragraph above, with the one exception that the $5,000 per ton exemption applied to both lean burn and rich burn engines. The state-only provision for rich-burn RICE (which reduces NOx emissions and is codified in Regulation No. 7, Sections XVII.E.3. and 3.a.) is being included as part of the Regional Haze SIP to become federally enforceable upon EPA approval.

For RICE NOx control under the Regional Haze rule, Colorado determines that the installation of NSCR on all rich burn RICE throughout the state satisfies RP requirements. The accompanying benefits of reducing VOCs and CO also support this RP determination. Additional NOx control for lean burn RICE throughout the state is not reasonable for this planning period.

For new and modified RICE of 100 hp or greater, the state is relying on emissions controls that are required by EPA's New Source Performance Standards (NSPS) Subpart JJJJ, 40 CFR Part 60 and EPA's National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart ZZZZ, 40 CFR Part 63. Colorado determines that this federal control program satisfies reasonable progress for these sources in this planning period.

For existing RICE less than 500 hp throughout the state, the state determines that no additional control is necessary for RP in this planning period. Colorado's emission inventory system indicates that in the 2007/2008 timeframe, there were 538 engines less than 500 hp in the state, and these engines emitted 5,464 tons/year of NOx. At an average of about 10 tons of NOx emissions per year, controlling engines of this size is not reasonable. Many of these smaller existing engines will eventually be brought into JJJJ and ZZZZ when modified in the future, so it is reasonable to assume that additional NOx reductions will occur.

The 2018 emissions inventory assumes approximately 16,199 tons of NOx per year from RICE of all sizes in Colorado. The NOx control achieved by controlling rich burn engines in the ozone control area (approximately 7,000 tons/year) is assumed in this number. Controlling the remaining rich burn engines statewide reduces the 2018 RICE

NOx emissions inventory by approximately 5,800 tons/year to approximately 10,400 tons/year. For new RICE subject to the NSPS and NESHAP, NOx emissions reductions have not been estimated. Because the 2018 estimate of 16,199 tons/year of NOx assumed growth in uncontrolled engines and did not account for th NSPS and NESHAP, the 10,400 ton/year emissions in 2018 should be even lower. The remaining NOx from engines is attributed to existing lean burn engines which are uncontrolled for NOx (though they will eventually be brought into JJJJ and ZZZZ when modified in the future), existing rich burn engines after control, small engines, and new RICE after the application of JJJJ and ZZZZ.

A detailed 4-factor analysis for RICE can be found in Appendix D.

8.3.3 Combustion Turbines

Combustion turbines fueled by natural gas or oil are either co-located with coal-fired electric generating units or as stand-alone facilities. These units are primarily used to supplement power supply during peak demand periods when electricity use is highest. Combustion turbine units start quickly and usually operate only for a short time. However, they are capable of operating for extended periods. Combustion turbine units are also capable of operating together or independently.

Information regarding combustion turbine emissions is well recorded in the state's air emissions inventory. Typical emissions for this source type may be significant for NOx, but pipeline quality natural gas is inherently clean and low-emitting for SO2 and PM10 emissions. Combustion turbines are subject to 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines, which limit sulfur content to 0.8 percent by weight, supported by monitoring and testing. Subpart GG also limits nitrogen oxides to 117.8 percent by volume at 15 percent oxygen on a dry basis (60.332(a)(1)), supported by monitoring and testing. The majority of combustion turbines are installed with Continuous Emissions Monitoring Systems (CEMs).

RP evaluations are triggered for turbines that are co-located at BART or RP sources that have been determined to be significant because they have a Q/d impact of greater than 20 (see section 8.3 below for a description of this "significance" determination). The state analyzed total state-wide combustion turbine emissions averaged over the 2006 – 2008 Reasonable Progress baseline period. There are five Reasonable Progress facilities with combustion turbines – PSCo Valmont Generating Station, PSCo Arapahoe Generating Station, Colorado Springs Utilities Nixon Plant, Platte River Power Authority Rawhide Energy Station, and PSCo Pawnee Generating Station. Of these, only two turbines located at the Nixon Plant emit significant levels of visibility impairing emissions, as defined by the federal Prevention of Significant Deterioration (PSD) significance levels:

- NO_x – 40 tons per year
- SO_2 – 40 tons per year
- PM_{10} – 15 tons per year

Facility – Turbine	Total 2006 – 2008 Averaged NOx Annual Emissions (tpy)	Total 2006 – 2008 Averaged SO2 Annual Emissions (tpy)	Total 2006 – 2008 Averaged PM10 Annual Emissions (tpy)	Greater than *de minimis* levels?
Front Range Power Plant – Turbine #1	159.6	2.9	4.9	Yes – NOx only
Front Range Power Plant – Turbine #2	147.9	2.8	4.9	Yes – NOx only

The combustion turbines at the Front Range Power Plant were installed with advanced dry-low NOx combustion systems, and based on 2006 – 2008 CEMs data and AP-42 emission factors, are achieving 89.4% and 90.1% NOx reductions, respectively.

There is one feasible emission control technology available for these turbines is adding post combustion technology – selective catalytic reduction (SCR) which, in good working order can achieve removal efficiencies ranging from 65 – 90 percent from uncontrolled levels.

Applying SCR would achieve up to an additional 90% control efficiency to both turbines and could result in about 275 tons of NOx reduced annually with a capital expenditure of at least $15 million. The state estimates that SCR for these turbines will range from approximately $57,000 - $62,000 per ton of NOx reduced annually. In the state's judgment for this planning period for Reasonable Progress, the potential 275 tons per year of NOx reductions are not cost-effective. The state has determined that NOx RP for combustion turbines is existing controls and emission limits.

A detailed 4-factor analysis for combustion turbines can be found in Appendix D.

8.4 Determination of Point Sources Subject to Reasonable Progress Evaluation

Colorado refined the RP analysis referred to in Section 8.2 (using the latest WRAP emission inventory data) to select specific point sources to evaluate for RP control[38]. This RP screening methodology involves a calculated ratio called "Q-over-d", that evaluates stationary source emissions (mathematical sum of actual SO2, NOx and PM emissions in tons per year, denoted as "Q") divided by the distance (in kilometers, denoted as "d") of the point source from the nearest Class I area.

The State evaluated the visibility impact sensitivity of different Q/d thresholds and determined that a Q/d ratio equal to or greater than "20" approximated a delta deciview (Δdv) impact ranging from 0.06 Δdv to 0.56 Δdv. The resultant average of the range is about 0.3 Δdv, which is a more conservative RP threshold than the 0.5 Δdv that was used in determining which sources would be subject-to-BART under the federal BART regulations. The delta deciview impact was determined by evaluating CALPUFF

[38] *Reasonable Progress Analysis of Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas,* March 31, 2010. See the Technical Support Document

modeling, conducted by the state in 2005, for the ten subject-to-BART stationary sources. Since the Q/d methodology involves consideration of PM emissions, the state has added PM (PM-10) emissions to the RP evaluation process.

The evaluation of potential RP sources involved all Colorado stationary sources with actual SO2, NOx or PM10 emissions over 100 tons per year based on Air Pollution Emissions Notice (APEN) reports from 2007. The one-hundred-thirteen (113) sources identified as exceeding the 100 tons/year threshold for any of the three pollutants (see Figure 8-3) were further analyzed, using ArcGIS mapping, to determine the exact distance from the centroid of the source to the nearest Class I area boundary. The Q/d was calculated for each source, and Table 8-1 lists the sixteen (16) point sources that are equal to or greater than the Q/d of 20 threshold. These sixteen sources will be referred to as “significant” sources for purposes of reasonable progress.

Figure 8-3: Point Sources with >100 TPY of Emissions

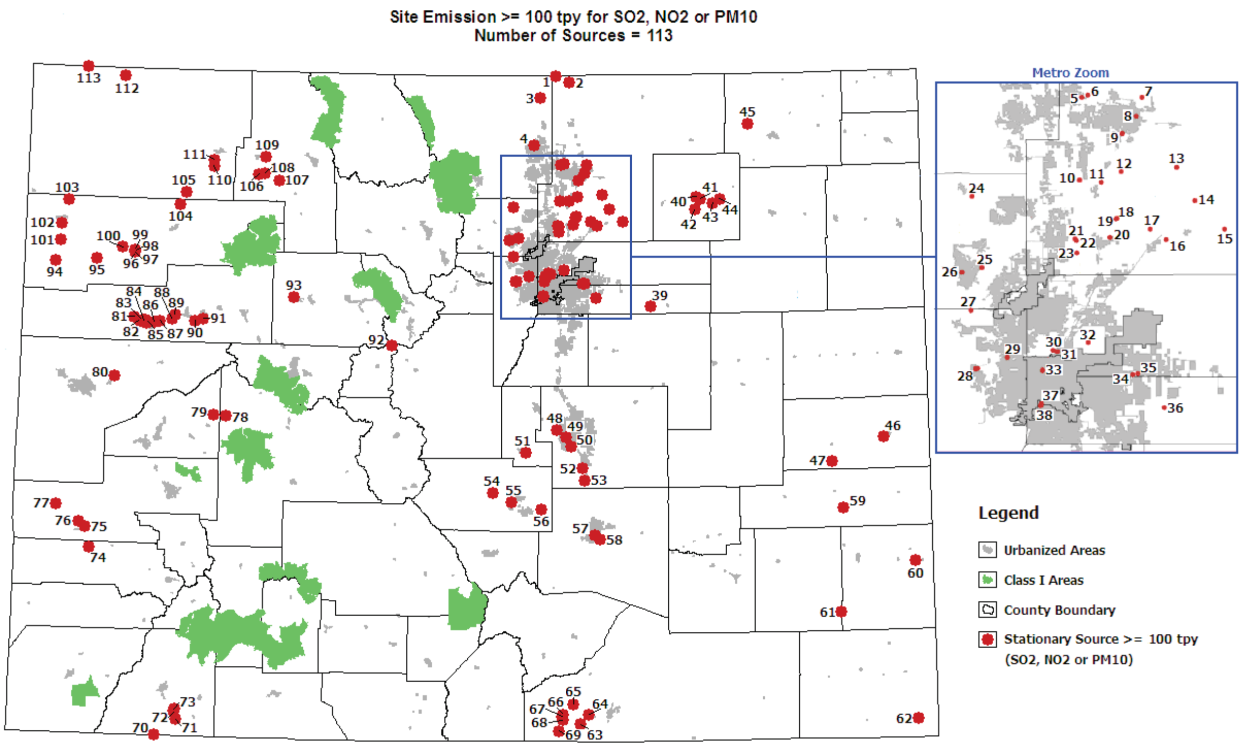


Table 8-1: Colorado Significant Point Sources with a Q/d ≥ 20

ArcGIS DATA - Statewide Sources over 100 tpy for SO2, NOx and PM10 (based on 2007 data)

Count	FACILITY NAME	SO2 [tpy]	NO2 [tpy]	PM10 [tpy]	Q [tpy]	Closest CIA	d [km]	Q/d
1	PLATTE RIVER POWER AUTHORITY - RAWHIDE	854	1,808	134	2,796	Rocky Mnt NP	56.0	49.9
2	CEMEX INC. - LYONS CEMENT	87	2,479	418	2,984	Rocky Mnt NP	24.8	120.3
3	PUBLIC SERVICE CO - VALMONT	749	2,355	58	3,162	Rocky Mnt NP	34.8	90.9
4	COLORADO ENERGY NATIONS CORPORATION	2,626	1,786	42	4,453	Rocky Mnt NP	54.5	81.7
5	PUBLIC SERVICE CO - CHEROKEE	7,116	10,205	261	17,581	Rocky Mnt NP	65.3	269.2
6	PUBLIC SERVICE CO - ARAPAHOE	2,496	2,922	178	5,595	Rocky Mnt NP	73.3	76.3
7	PUBLIC SERVICE CO - PAWNEE	13,073	4,645	193	17,911	Rocky Mnt NP	155.7	115.0
8	COLORADO SPRINGS UTILITIES - DRAKE	8,431	3,826	251	12,507	Great Sand Dunes NP	114.0	109.7
9	COLORADO SPRINGS UTILITIES - NIXON	3,883	2,656	129	6,668	Great Sand Dunes NP	104.4	63.9
10	AQUILA INC. - W.N. CLARK STATION	1,480	869	44	2,393	Great Sand Dunes NP	58.7	40.8
11	HOLCIM (US) INC. PORTLAND CEMENT	372	2,589	288	3,250	Great Sand Dunes NP	66.0	49.2
12	PUBLIC SERVICE CO - COMANCHE	13,854	8,415	178	22,447	Great Sand Dunes NP	84.5	265.6
13	TRI STATE GENERATION - NUCLA	1,509	1,716	101	3,327	Black Canyon NP	70.6	47.1
14	PUBLIC SERVICE CO - CAMEO	2,586	1,051	112	3,750	Black Canyon NP	70.5	53.2
15	PUBLIC SERVICE CO - HAYDEN	2,657	7,694	284	10,634	Mt Zirkel WA	31.6	336.5
16	TRI STATE GENERATION - CRAIG	3,586	16,807	235	20,628	Flat Tops WA	47.7	432.4
	Totals:	65,358	71,821	2,906				

Note that the APEN reports may not represent actual annual emissions, as Colorado Regulation 3 requires APEN reports to be updated every five years if no significant emissions increases have occurred at the source. Further, sources do not pay APEN emission fees on fugitive dust, thus sources with significant fugitive dust emissions may report potential rather than actual emissions in the APEN. The state contacted sources to ensure that actual emissions were used as much as possible since many sources over-estimate emissions in APENs. This ensures that correct emissions are used for the purposes of Reasonable Progress.

Set forth below are summaries of each of the sixteen significant sources. Many of these are BART sources, and emission control analyses and requirements for those sources are documented in Chapter 6 of this document. The BART determinations represent best available retrofit control and also satisfy RP requirements, and no further assessment of emissions controls for these facilities is necessary for reasonable progress during this planning period. In this regard, the state has already conducted BART analyses for its BART sources that are largely based on an assessment of the same factors to be addressed in establishing RPGs. Thus, Colorado has reasonably concluded that any control requirements imposed in the BART determination also satisfy the RP related requirements in the first planning period. *See* U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 4-2 (June 2007).

1. The state has determined that Platte River Power Authority's Rawhide Power Plant (unit 1) is a subject-to-RP source and has conducted an emission control analysis for the unit (see below).
2. The CEMEX Portland cement manufacturing facility in Lyons, Colorado, is a subject-to-BART source that the Division reviewed for best available retrofit controls for SO2, NOx and PM emissions. The state has determined that the CEMEX BART determinations for the kiln and the dryer (see Chapter 6) satisfy the SO2, NOx and PM BART/RP requirements in this planning period.
3. The Public Service Company of Colorado (PSCo) Valmont Power Plant (unit 5) is a subject-to-BART source that is included in a better than BART alternative for SO2

and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the state has determined that the facility's closure by 2018 satisfies the PM BART/RP requirements in this planning period.

4. The Colorado Energy Nations Corporation (CENC) operates two subject-to-BART industrial boilers (boilers 4 & 5) that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The CENC BART determination for these two boilers (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period. For boiler 3, the state has determined it to be subject-to-RP and has conducted an emission control analysis for the boiler (see below).
5. The PSCo Cherokee Power Plant has four units (1, 2, 3 & 4); unit 4 is a subject-to-BART source. All of the units are included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the closure of units 1, 2 and 3 by 2018 satisfies the PM RP requirements in this planning period. For unit 4, the BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
6. The PSCo Arapahoe Power Plant (units 3 & 4) is a subject-to-RP source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the closure of unit 3 by 2018 satisfies the PM RP requirements in this planning period; for unit 4 the conversion to repower from coal to natural gas satisfies the PM RP requirements in this planning period.
7. The PSCo Pawnee Power Plant (unit 1) is a subject-to-BART source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. The BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
8. The Colorado Springs Utilities (CSU) Drake Power Plant (units 5-7) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Drake BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.
9. The state has determined that the CSU Nixon Plant (unit 1) and the co-located Front Range Power Plant are subject-to-RP sources and has conducted emission control analyses for these sources (see below).
10. The state has determined that the Black Hills Energy Clark Power Plant (units 1 and 2) is a subject-to-RP source and has conducted an emission control analysis for the source (see below).
11. The state has determined that the Holcim Portland cement manufacturing facility (kiln and dryer) is subject-to-RP and has conducted an emission control analysis for the source (see below).
12. The PSCo Comanche Power Plant (units 1 and 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Comanche BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.

13. The state has determined that the Tri-State Generation and Transmission Association's Nucla Power Plant is subject-to-RP and has conducted an emission control analysis for the source (see below).
14. The state has determined that the PSCo Cameo Power Plant is subject-to-RP. With the closure of the facility by 2012, the SO2, NOx, and PM RP requirements are satisfied in this planning period. A regulatory closure requirement is contained in this chapter and in Regulation No. 3.
15. The PSCo Hayden Power Plant (units 1 & 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Hayden BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.
16. The Tri-State Generation and Transmission Association's Craig Power Plant has three units (1, 2, and 3); units 1 & 2 are subject-to-BART that the Division reviewed for best available retrofit controls for SO2, NOx and PM emissions. The BART determinations for units 1 and 2 (see Chapter 6) satisfy the SO2, NOx and PM BART/RP requirements in this planning period. The state has determined that unit 3 is subject-to-RP and has conducted an emission control analysis for the unit (see below).

Consequently, there are seven significant sources identified as subject-to-RP that Colorado has evaluated for controls in the RP analysis process:

- Rawhide Unit 1
- CENC Boiler 3
- Nixon Unit 1
- Clark Units 1, 2
- Holcim Kiln, Dryer
- Nucla
- Craig Unit 3

8.5 Evaluation of Point Sources for Reasonable Progress

In identifying an appropriate level of control for RP, Colorado took into consideration the following factors:

(1) The costs of compliance,
(2) The time necessary for compliance,
(3) The energy and non-air quality environmental impacts of compliance, and
(4) The remaining useful life of any potentially affected sources.

Colorado has concluded that it also appropriate to consider a fifth factor: the degree of visibility improvement that may reasonably be anticipated from the use of RP controls. States have flexibility in how they take these factors into consideration, as well as any other factors that the state determines to be relevant. *See* U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 5-1 (June 2007).

8.5.1 Rationale for Point Source RP Determinations

Similar to the process for determining BART as described in Chapter 6, in making its RP determination for each Colorado source, the state took into consideration the five factors on a case-by case basis, and for significant NOx controls the state also utilized the guidance criteria set forth in Section 6.4.3 consistent with the factors. Summaries of the state's facility-specific consideration of the factors and resulting determinations for each RP source are provided in this Chapter 8. Documentation reflecting the state's analyses and supporting the state's RP determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix D of this document and the TSD.

8.5.1.1 The costs of compliance. The Division requested, and the companies provided, source-specific cost information for each RP unit. The cost information relates primarily to the installation and operation of new SO2 and NOx control equipment. The cost for each unit is summarized below, and the state's consideration of this factor for each source is presented in detail in Appendix D.

8.5.1.2 The time necessary for compliance.

Regulation No 3, Part F, Section VI.B.4. requires facilities subject to RP determinations to submit a compliance plan within 60 days of SIP approval. Based on Colorado facility submittals, the Division anticipates that the time necessary for facilities to complete design, permitting, procurement, and system startup, after SIP approval, would be approximately 3 - 5 years. This timeframe may vary somewhat due to the necessary major maintenance outage with other regionally affected utilities.

8.5.1.3 The energy and non-air quality environmental impacts of compliance. This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each RP unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO2, as further described below.

8.5.1.4 The remaining useful life of the source. For those sources set to retire by 2018, the state established a regulatory closure requirement in this chapter and in Regulation No. 3. For those sources not expected to retire over the next twenty years, this factor did not affect any of the state's RP determinations.

8.5.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of RP. The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of RP control, where relevant and the information was available, although degree of visibility improvement is not an express element of four factors to be considered during reasonable progress under EPA's federal regulations and guidelines. Modeling information where relevant and available for each RP determination is presented below and in Appendix D.

8.5.1.6 Overview of the RP Determinations for Each Source. This section presents an overview of the RP determinations for the significant point sources not addressed in Chapter 6.

The regional haze rule gives the states broad latitude on how the four statutory factors, and any other factors a state deems to be relevant, may be considered to determine the appropriate controls for RP. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the factors in reaching a determination. The manner and method of consideration is left to the state's discretion; states are free to determine the weight and significance to be assigned to each factor.

The Division has reviewed available particulate controls applicable to RP facilities. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM". *See,* 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix D.

The Division also reviewed various SO2 controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 8, in Appendix D and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. *See,* 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix D.

With respect to NOx controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NOx controls, as appropriate.

When determining the emission rates for each source, the state referred to the available literature and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that RP relates to retrofitting sources (vs. new or reconstructed facilities), a review of other BART and RP determinations used to better substantiate the source specific information provided by the source.

For the purposes of the RP review for the three pollutants that the state is assessing for the seven facilities, SO2 and PM have been assessed utilizing the factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO2 and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NOx controls on reasonable progress electric generating units, for reasons described below, the state is employing guidance criteria to aid in its RP assessment, largely because significant NOx add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of control for these sources.

With respect to SO2 emissions, there are currently ten flue gas desulphurization lime spray dryer (LSD) SO2 control systems operating at electric generating units in Colorado.[39] There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO2 emissions in the state and other non-air quality considerations. The state has determined in the past that these systems can be cost-effective for sources in Colorado. With this familiarity and use of the emissions control technology, the state has assessed SO2 emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to NOx emissions, post-combustion controls for NOx are generally not employed in Colorado. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are currently no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NOx emissions.

In assessing and determining appropriate NOx controls at significant sources for individual units for visibility improvement under the Regional Haze rule, for reasonable progress, the state has considered the relevant factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight. In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors.

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[39] EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, Valmont Unit 5.

More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (*e.g.*, expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NOx) from the atmosphere, or $/ton of NOx removed); and, (ii) visibility improvement expected from the control options analyzed (*e.g.*, expressed as visibility improvement in delta deciview (Δdv) from CALPUFF air quality modeling).

Accordingly, as part of its reasonable progress factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state's general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of RP control on a case by case basis.

The cost criteria presented above is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls. For example, the $5,000/ton criterion is consistent with Colorado's retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.[40] In that case, a $5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.[41] The $5,000/ton criterion is also consistent with and within the range of the state's implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control

[40] Air Quality Control Commission Regulation No. 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

[41] The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

costs for Colorado RACT can be in the range of \$5,000/ton (and lower), while control costs for Colorado BACT can be in the range of \$5,000/ton (and higher).

In addition, as it considers the pertinent factors for reasonable progress, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NOx controls, *i.e*., SCR, have the ability to provide significant NOx reductions, but also have initial capital dollar requirements that can approach or exceed \$100 million per unit.[42] The lesser-performing post-combustion NOx controls, *e.g*., SNCR, reduce less NOx on a percentage basis, but also have substantially lower initial capital requirements, generally less than \$10 million.[43] The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NOx controls (*i.e*., SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.[44] For the lesser-performing add-on NOx controls (*e.g*., SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area.

Employing the foregoing guidance criteria for post-combustion NOx controls, as part of considering the relevant factors for reasonable progress, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

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[42] *See, e.g.,* Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, \$83MM; Public Service of Colorado, Hayden Unit #2, \$72MM; Tri-State Generation and Transmission, Craig Station Unit #1, \$210MM.

[43] *See, e.g*., Appendix C, reflecting CENC (Tri-gen), Unit #4, \$1.4MM; Public Service Company of Colorado, Hayden Unit #2, \$4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, \$13.1MM

[44] The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. Colorado is applying these same criteria to RP sources, as a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

8.5.2 Point Source RP Determinations

The following summarizes the RP control determinations that will apply to each source.

Table 8-2 RP Control Determinations for Colorado Sources

Emission Unit	Assumed** NOx Control Type	NOx Emission Limit	Assumed** SO_2 Control Type	SO_2 Emission Limit	Assumed** Particulate Control and Emission Limit
Rawhide Unit 101	Enhanced Combustion Control*	0.145 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
CENC Unit 3	No Control	246 tons per year (12-month rolling total)	No Control	1.2 lbs/MMBtu	Fabric Filter Baghouse* 0.07 lb/MMBtu
Nixon Unit 1	Ultra-low NOx burners with Over-Fire Air	0.21 lb/MMBtu (30-day rolling average)	Lime Spray Dryer	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Clark Units 1 &2	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Holcim - Florence Kiln	SNCR	2.73 lbs/ton clinker (30-day rolling average) 2,086.8 tons/year	Wet Lime Scrubber*	1.30 lbs/ton clinker (30-day rolling average) 721.4 tons/year	Fabric Filter Baghouse* 246.3 tons/year
Nucla	No Control	0.5 lb/MMBtu (30-day rolling average)	Limestone Injection*	0.4 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 3	SNCR	0.28 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.15 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.013 lb/MMBtu filterable PM 0.012 lb/MMBtu PM10
Cameo	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011

* Controls are already operating

** Based on the state's RP analysis, the "assumed" technology reflects the control option found to render the RP emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

For all RP determinations, approved in the federal State Implementation Plan, the state affirms that the RP emission limits satisfy Regional Haze requirements for this planning period (through 2017) and that no other Regional Haze analyses or Regional Haze controls will be required by the state during this timeframe.

The following presents an overview of Colorado's RP control determinations:

8.5.2.1 RP Determination for Platte River Power Authority - Rawhide Unit 101

This facility is located in Larimer County approximately 10 miles north of the town of Wellington, Colorado. Unit 101 is a 305 MW boiler and is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Platte River Power Authority (PRPA) submitted a "Rawhide NOx Reduction Study" on January 22, 2009 as well as additional relevant information on May 5 and 6, 2010.

SO2 RP Determination for PRPA Rawhide Unit 101

Dry FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing control achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Rawhide Unit 101 operates a lime spray dryer FGD currently achieving over 72 percent SO2 reduction. The state has elected to consider EPA's BART Guidelines as relevant to the RP evaluation of Rawhide Unit 101 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. PRPA and the Division are not aware of SO_2 scrubber performance additives applicable to the Unit 101 SDA system.
- *Use of more reactive sorbent*: Lime quality is critical to achieving the current emission limit. PRPA utilizes premium lime at higher cost to ensure compliance with existing limits. The lime contract requires >92% reactivity (available calcium oxide) lime to ensure adequate scrubber performance. PRPA is already using a highly reactive sorbent, therefore this option is not technically feasible.
- *Increase the pulverization level of sorbent*: The fineness of sorbents used in dry-sorbent injection systems is a consideration and may improve performance for these types of scrubbers. Again, the Unit 101 SO_2 scrubber is a semi-dry SDA type scrubber that utilizes feed slurry that is primarily recycle-ash slurry with added lime slurry. PRPA recently completed SDA lime slaking sub-system improvements that are designed to improve the reactivity of the slaked lime-milk slurry.
- *Engineering redesign of atomizer or slurry injection system*: The Unit 101 SDA scrubber utilizes atomizers for slurry injection. The scrubber utilizes three reactor compartments, each with a single atomizer. PRPA maintains a spare atomizer to ensure high scrubber availability. The atomizers utilize the most current wheel-

nozzle design. The state and PRPA concur that PRPA utilizes optimal maintenance and operations; therefore, a lower SO2 emission cannot be achieved with improved maintenance and/or operations.

Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Rawhide Unit 101 – SO2 Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Fuel switching – NG	906	$237,424,331	$262,169

There are no energy and non-air quality impacts associated with this alternative.

There are no remaining useful life issues for the alternative as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to more stringent SO2 emission limits as a demonstration are as follows:

SO2 Control Method	SO2 Annual Emission Rate (lb/MMBtu)	98^{th} Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.11	
Existing Dry FGD	0.09	0.01
Dry FGD – tighter limit	0.07	0.03
Fuel switching – NG	0.00	0.87

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that SO2 RP is the following SO2 emission rates:

Rawhide Unit 101: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the installation and operation of lime spray dryers (LSD). The state has determined that these emissions rates are achievable without additional capital investment through the four-factor analysis. Upgrades to the existing SO2 control system were evaluated, and the state determines that meaningful upgrades to the system are not available. Lower SO2 limits would not result in significant visibility improvement (less than 0.02 delta deciview) and would likely result in frequent non-compliance events and, thus, are not reasonable.

Particulate Matter RP Determination for PRPA Rawhide

The state has determined that the existing Unit 101 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}.

The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx RP Determination for PRPA Rawhide

Enhanced combustion control (ECC), selective non-catalytic reduction (SNCR), fuel switching to natural gas (NG), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Rawhide Unit 101. Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Rawhide Unit 101 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
ECC	448	$288,450	$644
SNCR	504	$1,596,000	$3,168
Fuel switching – NG	545	$237,424,331	$435,681
SCR	1,185	$12,103,000	$10,214

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	NOx Annual Emission Rate (lb/MMBtu)	98^{th} Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.302	
ECC	0.126	0.45
SNCR	0.121	0.46
Fuel Switching – NG	0.118	0.47
SCR	0.061	0.59

It should be noted that the daily maximum (3-yr) value of 0.302 lb/MMBtu was a substituted value from CAMD. The next highest 24-hour value was 0.222 lb/MMBtu, 26% lower than the modeled value. However, the Division did not conduct revised modeling since it was determined that it would not change the State’s RP determination.

Switching to natural gas was eliminated from consideration due to the excessive cost/effectiveness ratio and degree of visibility improvement less than 0.5 dV.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Rawhide Unit 101 is the following NOx emission rate:

Rawhide Unit 1: 0.145 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of enhanced combustion control. The dollars per ton control cost, coupled with notable visibility improvements of 0.45 delta dv, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. SNCR would achieve similar emissions reductions to enhanced combustion controls and would afford a minimal additional visibility benefit (0.01 delta deciview), but at a significantly higher dollar per ton control cost compared to the selected enhanced combustion controls, so SNCR was not determined to be reasonable by the state.

A complete analysis that supports the RP determination for the Rawhide facility can be found in Appendix D.

8.5.2.2 RP Determination for Colorado Energy Nations Company (CENC) Boiler 3

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boiler 3 is considered by the State to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. CENC submitted a "Reasonable Progress Control Evaluation" on May 7, 2010 as well as additional relevant information on February 8, 2010.

The CENC facility includes five coal-fired boilers that supply steam and electrical power to Coors Brewery. Three of the boilers emit above 40 tons or more of haze forming pollution. Of these three boilers, Units 4 and 5 are subject to BART, and Unit 3 is subject to RP. Unit 3 is rated as follows: 225 MMBtu/hr, which is approximately equivalent to 24 MW, based on the design heat rate.

SO2 RP Determination for CENC – Boiler 3

Dry sorbent injection (DSI) and fuel switching to natural gas were determined to be technically feasible for reducing SO2 emissions from Boiler 3. Dry FGD is not technically feasible for Boiler 3 due to space constraints onsite. These options were considered as potentially RP by the state. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by PRPA it was evaluated by the state.

Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

CENC Boiler 3 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI – Trona	147	$1,340,661	$9,114
Fuel Switching – Natural Gas	245	$1,428,911	$5,828

DSI – Trona and fuel switching to natural gas were eliminated from consideration due to excessive cost/effectiveness ratio.

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider.

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce minimal visibility impacts (<<0.10 dv).

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is an emission rate of:

CENC Boiler 3: 1.2 lbs/MMBtu

Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement (<< 0.10 dv) afforded.

Particulate Matter RP Determination for CENC – Boiler 3

The state has determined that the existing Boiler 3 regulatory emissions limit of 0.07 lb/MMBtu (PM/PM10) corresponding with the original Industrial Boiler MACT standard represents the most stringent control option. The units are exceeding a PM control efficiency of 90%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for CENC – Boiler 3

Flue gas recirculation (FGR), selective non-catalytic reduction (SNCR), rotating overfire air (ROFA) fuel switching to natural gas, and three options for selective catalytic reduction (RSCR, HTSCR, and LTSCR) were determined to be technically feasible for reducing NOx emissions at CENC Boiler 3. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by CENC it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

CENC Boiler 3 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
FGR	33.7	$1,042,941	$30,929
SNCR	50.6	$513,197	$10,146
Fuel switching – NG	84.3	$1,428,911	$16,950
ROFA w/ Rotamix	77	$978,065	$9,496
Regenerative SCR	96.3	$978,065	$10,160
High temperature SCR	125.6	$1,965,929	$15,651
Low temperature SCR	144.5	$2,772,286	$19,187

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce visibility impacts below the guidance visibility criteria discussed in section 8.4 above.

All NOx control options were eliminated from consideration due to the excessive cost/effectiveness ratios and small degree of visibility improvement.

Based on review of historical actual load characteristics of this boiler, the state determines to be appropriate an annual NOx ton/year limit based on 50% annual capacity utilization based on the maximum capacity year in the last decade (2000). This annual capacity utilization will then have a 20% contingency factor for a variety of reasons specific to Boiler 3 further explained in Appendix D.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Boiler 3 is the following NOx emission rate

CENC Boiler 3: 246 tons/year (12-month rolling total)

Though other controls achieve better emissions reductions, the expense of these options coupled with predicted minimal visibility improvement (<< 0.10 dv) were determined to be excessive and above the guidance cost criteria discussed in section 8.4 of the Regional Haze SIP, and thus not reasonable

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is likely below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively (as demonstrated in the BART determination for CENC Boiler 4). Moreover, the incremental visibility improvement associated with SNCR or SCR is likely not substantial when compared to the visibility improvement achieved by the selected limits. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Boiler 3.

A complete analysis that supports the RP determination for the CENC facility can be found in Appendix D.

8.5.2.3 RP Determination for Colorado Springs Utilities' - Nixon Unit 1

The Nixon plant is located in Fountain, Colorado in El Paso County. Nixon Unit 1 and two combustion turbines at the Front Range Power Plant are considered by the Division to be eligible for the purposes of Reasonable Progress, being industrial sources with the potential to individually emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Colorado Spring Utilities (CSU) provided RP information in "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 and additional relevant information on May 10, 2010.

SO2 RP Determination for CSU – Nixon

Dry sorbent injection (DSI) and dry FGD were determined to be technically feasible for reducing SO2 emissions from Nixon. These options were considered as potentially RP by the state. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Nixon Unit 1 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI – Trona	2,473	$9,438,692	$1,997
Dry FGD @ 78% control (0.10 lb/MMBtu annual average)	3,215	$12,036,604	$3,744
Dry FGD @ 85% control (0.07 lb/MMBtu annual average)	3,392	$13,399,590	$3,950

The energy and non-air quality impacts of the remaining alternatives are as follows:

- DSI – reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as replacement for concrete and rendering it landfill material only
- Dry FGD – less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Nixon – Unit 1	
	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.45	
DSI	0.18	0.44
Dry FGD (LSD)	0.10	0.46
Dry FGD (LSD)	0.07	0.50

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience, 30-day SO2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 5% for all SO2 emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is the following SO2 emission rate:

Nixon Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with semi dry FGD (LSD). A lower emissions rate for Unit 1 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.04 delta deciview). Also, stringent retrofit emission limits below 0.10 lb/MMBtu have not been demonstrated in Colorado, and the state determines that a lower emission limit is not reasonable in this planning period.

The LSD control for Unit 1 provides 78% SO_2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 1: $3,744 per ton SO_2 removed; 0.46 deciview of improvement

An alternate control technology that achieves the emissions limits of 0.11 lb/MMBtu, 30-day rolling average, may also be employed.

Particulate Matter RP Determination for CSU – Nixon

The state determines that the existing Unit 1 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limits is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for CSU – Nixon

Ultra low NOx burners (ULNB), SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Nixon Unit 1.

The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Nixon Unit 1 - NO_x Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Ultra-low NOx Burners (ULNBs)	471	$567,000	$1,203
Overfire Air (OFA)	589	$403,000	$684
ULNBs+OFA	707	$907,000	$1,372
Selective Non-Catalytic Reduction (SNCR)	707	$3,266,877	$4,564
ULNB/SCR layered approach	1,720	$11,007,000	$6,398
Selective Catalytic Reduction (SCR)	1,720	$11,010,000	$6,400

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB – not significant
- ULNB – not significant
- SNCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Nixon – Unit 1	
	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.26	
ULNB	0.21	0.15
OFA	0.19	0.15
ULNB+OFA	0.18	0.16
SNCR	0.18	0.16
ULNB + SCR	0.07	0.24
SCR	0.07	0.24

SCR options were eliminated from consideration due to the excessive cost/effectiveness ratios and degree of visibility improvement.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Nixon Unit 1 is the following NOx emission rates:

Nixon Unit 1: 0.21 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with ultra-low NOx burners with over fire air control. The Division notes that the ultra-low NOx burners with over-fire air-based emissions limit is the appropriate RP determination for Nixon Unit 1 due to the low cost effectiveness. SNCR would achieve similar emissions reductions at an added expense. Therefore, SNCR was determined to not be reasonable considering the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above RP determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.01 dv for SNCR and 0.09 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Nixon Unit 1.

A complete analysis that supports the RP determination for the Nixon Plant can be found in Appendix D.

8.5.2.4 RP Determination for Black Hills Clark Facility Units 1 and 2

Black Hills/Colorado Electric Utility Company, LP informed the state that the Clark Station in the Cañon City, Colorado area will be shutdown 12/31/2013, resulting in SO2, NOx and PM reductions of approximately 1,457, 861, and 72 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

8.5.2.5 RP Determination for Holcim's Florence Cement Plant

The Holcim Portland cement plant is located near Florence, Colorado in Fremont County, approximately 20 kilometers southeast of Canon City, and 35 kilometers northwest of Pueblo, Colorado. The plant is located 66 kilometers from Great Sand Dunes National Park.

In May 2002, a newly constructed cement kiln at the Portland Plant commenced operation. This more energy-efficient 5-stage preheater/precalciner kiln replaced three older wet process kilns. As a result, Holcim was able to increase clinker production from approximately 800,000 tons of clinker per year to a permitted level of 1,873,898 tons of clinker per year, while reducing the level of NO_X, SO_2, and PM/PM_{10} emissions on a pound per ton of clinker produced basis. As a part of this project, Holcim also installed a wet lime scrubber to reduce the emissions of sulfur oxides.

The Portland Plant includes a quarry where major raw materials used to produce Portland cement, such as limestone, translime and sandstone, are mined, crushed and then conveyed to the plant site. The raw materials are further crushed and blended and then directed to the kiln feed bin from where the material is introduced into the kiln.

The dual string 5-stage preheater/precalciner/kiln system features a multi-stage combustion precalciner and a rotary kiln. The kiln system is rated at 950 MMBtu per hour of fuel input with a nominal clinker production rate of 5,950 tons per day. It is permitted to burn the following fuel types and amounts (with nominal fuel heat values, where reported):

- coal (269,262 tons per year [tpy] @ 11,185 Btu/pound);
- tire derived fuel (55,000 tpy @ 14,500 Btu/pound);
- petroleum coke (5,000 tpy @ 14,372 Btu/pound);
- natural gas (6,385 million standard cubic feet @ 1,000 Btu/standard cubic foot);
- dried cellulose (55,000 tpy); and
- oil, including non-hazardous used oil (4,000 tpy @ 12,000 Btu/pound).

The clinker produced by the kiln system is cooled, grounded and blended with additives and the resulting cement product is stored for shipment. The shipment of final product from the plant is made by both truck and rail.

Emissions from the kiln system, raw mill, coal mill, alkali bypass and clinker cooler are all routed through a common main stack for discharge to atmosphere. These emissions are currently controlled by fabric filters (i.e., baghouses) for PM/PM_{10}, by the inherent recycling and scrubbing of exhaust gases in the cement manufacturing process and by a tail-pipe wet lime scrubber for SO_2, by burning alternative fuels (i.e., tire-derived fuel [TDF]) and using a Low-NO_X precalciner, indirect firing, Low-NO_X burners, staged combustion and a Linkman Expert Control System for NO_X, and by the use of good combustion practices for both NO_X and SO_2.In addition to the kiln system/main stack emissions, there are two other process points whose PM/PM_{10} emissions exceed the Prevention of Significant Deterioration (PSD) significance level thresholds and were considered as a part of this Reasonable Progress analysis: 1) the raw material extraction and alkali bypass dust disposal operations associated with the quarry, and 2) the cement processing operations associated with the finish mill. Emissions from the quarry are currently controlled through a robust fugitive dust control plan and emissions from the finish mills are controlled by a series of baghouses.

Holcim did not initially complete a detailed four-factor analysis, though it did submit limited information on the feasibility of post-combustion NO_X controls for the kiln system. In late October through early December 2010, Holcim did submit detailed information, including data on baseline emissions, existing controls and additional control options, and visibility modeling to support the reasonable progress determination process. This section has been revised to reflect this additional information.

CALPUFF modeling was conducted by the Division for the kiln system, as a part of our original analysis, using a SO_2 emission rate of 99.17 lbs/hour, a NO_X emission rate of

837.96 pounds per hour (lbs/hour), and a PM_{10} emission rate of 19.83 lbs/hour. The modeling indicates a 98th percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park. Holcim provided additional visibility modeling results in a submittal made in late October 2010.

Because of the high level of existing fugitive dust controls employed at the quarry and the baghouse controls already installed on the finish mill emission points, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable additional controls on these points. Accordingly, the state has determined that no additional visibility analysis is necessary or appropriate since even the total elimination of the emissions from the quarry and finish mill would not result in any meaningful visibility improvement. For the quarry, the current PM_{10} emission limitation is 47.9 tpy (fugitive) and for the finish mill it is 34.3 tpy (point source). These limitations are included in the existing Holcim Portland Plant construction permit.

SO_2 RP Determination for Holcim Portland Plant – Kiln System

In addition to good combustion practices and the inherent recycling and scrubbing of acid gases by the raw materials, such as limestone, used in the cement manufacturing process, the Portland Plant kiln system has a tail-pipe wet lime scrubber. Holcim has reported that this combination of controls achieves an overall sulfur removal rate of 98.3% for the kiln system, as measured by the total sulfur input in to the system versus the amount of sulfur emitted to atmosphere. Holcim has also reported that they estimate that the wet scrubber at the Portland Plant achieves an overall removal efficiency of over 90% of the SO_2 emissions entering the scrubber. This control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding SO2 emissions rates. The facility is currently permitted to emit 1,006.5 tpy of SO2 from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 1.08 pounds of SO2 per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for SO2). The actual kiln SO2 emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 0.51 pound of SO2 per ton of clinker, with a standard deviation of 0.26 pound per ton. The highest annual emission rate in the baseline years was 0.95 pound per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for SO_2. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emissions limit of 1.30 pounds of SO_2 per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability. The long-term annual limit was calculated at 721.4 tpy by multiplying the long-term baseline SO_2 value of 0.77 lb/ton (the mean of 0.51 pound per ton plus one standard deviation of 0.26 pound per ton) by the annual clinker limit of 1,873,898 tpy, and then dividing by 2,000 pounds per ton.

Because there are no changes to the existing controls for SO2, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

For the kiln system, based upon our consideration and weighing of the four factors, the state has determined that no additional SO2 emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technologies – the inherent recycling and scrubbing effect of the process itself followed by a tail-pipe wet lime scrubber. The RP analysis provides sufficient basis to establish a short-term SO_2 emission limit of 1.30 pound per ton of clinker on a 30-day rolling average basis and a long-term annual emission limit of 721.4 tons of SO_2 per year (12-month rolling total) for the kiln system. There is no specific visibility improvement associated with this emission limitation.

Finally, on August 9, 2010, EPA finalized changes to the New Source Performance Standards (NSPS) for Portland Cement Plants and to the Maximum Achievable Control Technology standards for the Portland Cement Manufacturing Industry (PC MACT). The NSPS requires, new, modified or reconstructed cement kilns to meet an emission standard of 0.4 pound of SO2 per ton of clinker on a 30-day rolling average or a 90% reduction as measured at the inlet and outlet of the control device. While the new NSPS does not apply to the Holcim Portland Plant because it is an existing facility, it is important to note that the estimated level of control achieved by Holcim's wet scrubber (~90%) is consistent with the level of control prescribed by the NSPS for new sources.

Particulate Matter RP Determination for Holcim Portland Plant – Kiln System

The state has determined that the existing fabric filter baghouses installed on the kiln system represent the most stringent control option. Holcim has reported a nominal control efficiency for the kiln system baghouses at 99.5%. The units are exceeding a PM control efficiency of 95% and this control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding PM_{10} emissions rates. The facility is currently permitted to emit 246.3 tpy of PM_{10} from the kiln system main stack (includes emissions from the clinker cooler). At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 0.26 pound of PM_{10} per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for PM_{10}). The actual kiln system PM_{10} emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) average to a rate of 0.16 pound of PM_{10} per ton of clinker (combined emissions from main stack). This value is derived from the limited annual stack test data, which are effectively snapshots in time, and does not take into account the short-term inherent variability in the manufacturing process, raw material and fuel.

Because there are no changes to the existing controls for PM_{10}, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

As a part of our original analysis, the state modeled possible visibility improvements associated with two emission rates – the baseline emission rate of 0.08 pound of PM_{10} per ton of clinker (19.83 lbs/hour) and a rate of 0.04 pound of PM_{10} per ton of clinker (9.92 lbs/hour). This analysis assumed the baseline emissions were all attributable to the kiln (i.e., no contribution from the clinker cooler) to assess the impact of a possible reduction of the kiln emission limit. There was no change to the 98th percentile impact deciview value from 19.83 lbs/hour to 9.92 lbs/hour and therefore, no visibility improvement associated with this change. The state's modeling results showed that the most significant contributors to the visibility impairment from the Portland Plant were nitrates (NO_3) followed by sulfates (SO_4).The contribution of PM_{10} to the total visibility impairment was insignificant in the analysis. The level of PM_{10} emissions evaluated had no discernable impact on visibility.

For the kiln system, based upon our consideration and weighing of the four factors and the very limited impact of PM_{10} emissions from the kiln system on visibility impairment, the state has determined that no additional PM_{10} emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technology – fabric filter baghouses. These baghouses and the current permit limit of 246.3 tpy of PM_{10} (12-month rolling total) from the kiln system main stack (including emissions from the clinker cooler) represent RP for this source. Furthermore, the Portland Plant is subject to the PC MACT and the recent amendments to the PC MACT include new, lower standards for PM emissions. As an existing facility, the Portland Plant kiln system will be subject to this standard once it becomes effective on September 9, 2013. Compliance with the new PC MACT PM emission standards will result in further reductions in the PM_{10} emissions.

NO_X RP Determination for Holcim Portland Plant – Kiln System

There are a number of technologies available to reduce NO_X emissions from the Portland Plant kiln system below the current baseline emissions level (the current configuration already includes indirect firing, low-NO_X burners, staged combustion, a low-NO_X precalciner, and a Linkman Process Control Expert system). These include water injection (the injection of water or steam into the main flame of a kiln to act as a heat sink to reduce the flame temperature), and selective non-catalytic reduction (SNCR). These technologies were determined to be technically feasible and appropriate for reducing NO_X emissions from Portland cement kilns.

As further discussed in Appendix D, the state has determined that selective catalytic reduction (SCR) is not commercially available for the Portland Plant cement kiln system. Presently, SCR has not been applied to a cement plant of any type in the United States. Holcim notes that the major SCR vendors have either indicated that SCR is not commercially available for cement kilns at this time, or if they are willing to provide a quotation for an SCR system, the associated limitations that are attached with the quote severely undercut the efficacy of the system. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe constitutes reasonable “available” control technology for purposes of RP at the Holcim Portland Plant. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is “available” for purposes of retrofitting such control technology on an existing source.

In the preamble to the recently finalized changes to the Portland Cement MACT/NSPS, EPA stated: “However, although SCR has been demonstrated at a few cement plants in Europe and has been demonstrated on coal-fired power plants in the US, the Agency is not satisfied that it has been sufficiently demonstrated as an off-the-shelf control technology that is readily applicable to cement kilns.” Based on our research and EPA’s analysis for the MACT/NSPS standards, the state has eliminated SCR as an available control technology for purposes of this RP analysis.

The design of the Holcim Portland Plant does allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia-like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing NO_X to elemental nitrogen. Holcim has indicated to the state that SNCR is technically and economically feasible for the Portland Plant. In April 2008, Holcim provided information to the state on SNCR systems that was based on trials that were conducted at the plant in the 4^{th} quarter of 2006. Holcim estimated that NO_X emissions could be reduced in the general range of 60 to 80% (based on a 1,000 pound per hour emission rate) at an approximate cost of $1,028 per ton. This was based on a short-term testing and showed considerable ammonia slip which could cause significant environmental, safety and operational issues.

The facility is currently permitted to emit 3,185.7 tpy of NOX from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 3.40 pounds of NOX per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for NOX). The actual kiln NOX emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 3.43 pounds of NOX per ton of clinker, with a standard deviation of 0.21 pound per ton. The highest annual emission rate in the baseline years was 3.67 pounds per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for NOX. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emission rate of 4.47 pounds of NOX per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability.

Holcim is permitted to burn up to 55,000 tpy of TDF annually and has been using TDF during the baseline years. Use of TDF as a NOX control strategy has been well documented and recognized by EPA. A reduction in NOX emissions of up to 30% to 40% has been reported. Since the TDF market and possible associated TDF-use incentives are unpredictable and TDF's long-term future availability is unknown, the baseline emission rate was adjusted upward by a conservative factor of 10% to account for the NOX reduction in the baseline years as a result of the use of TDF during this baseline period that might not be available in future years. This increased the baseline 30-day rolling average emissions rate from 4.47 to 4.97 pounds of NOX per ton of clinker.

An SNCR control efficiency of 50% is feasible for the Portland Plant kiln that already has number of technologies available to reduce NOX emissions including indirect firing, low-NOX burners, staged combustion, a low-NOX precalciner, and a Linkman Process Control Expert system. However, to achieve the necessary system configuration and temperature profile, SNCR will be applied at the top of the preheater tower and thus the alkali bypass exhaust stream cannot be treated. To achieve the proper cement product specifications, the Portland Plant alkali bypass varies from 0 - 30% of main kiln gas flow. Adjusting by 10%, (conservative estimate) for the alkali bypass to account for the exhaust gas that is not treated (i.e., bypassed) by the SNCR system, the overall SNCR control efficiency for the main stack will be 45%.

Based on the above discussion, the 30-day rolling average short-term limit was calculated at 2.73 pounds of NOX per ton of clinker by adjusting upward the short-term baseline emission rate of 4.47 pounds of NOX per ton clinker by 10% for TDF and then accounting for SNCR 45% overall control efficiency [4.47/0.9*(1-0.45) = 2.73]. The long-term annual limit was calculated at 2,086.8 tpy by adjusting upward the annual baseline emission rate of 3.64 lbs/ton clinker (the mean of 3.43 pounds per ton plus one standard deviation of 0.21 pound per ton) by 10% for TDF and then accounting for SNCR 45% overall control efficiency [3.64/0.9*(1-0.45) = 2.23 lb/ton]. This calculated value of 2.23 pounds per ton was then multiplied by the annual clinker limit of 1,873,898 tpy, and then divided by 2,000 pounds per ton to arrive at the 2,086.8 tpy NOX limit.

Because SNCR with existing LNB is technically and economically feasible, the state did not further consider water injection because the level of control associated with this option is not as high as with SNCR.

The following table lists the most feasible and effective option (SNCR):

NOx Control Technology	Estimated Control Efficiency	30-day Rolling Average Emissions (lb/ton of Clinker)	Annual Controlled NOx Emissions (tpy)
Baseline NOx Emissions	-	4.97	3,185.7*
SNCR w/ existing LNB	45%**	2.73	2,086.8

* Defaulted to the permit limit since the calculated baseline was higher.

** This is calculated based on the 50% SNCR removal efficiency and 10% bypass

There are no significant associated energy and non-air quality impacts for SNCR in operation on a Portland cement plant. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

Holcim Portland Plant – Kiln System				
NOx Control Technology	NOx Emission Reduction (tons/yr)	Annualized Cost ($/yr)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline NOx Emissions	-			
SNCR w/existing LNB (45% control)	1,098.9	$2,520,000*	$2,293	-

* Annualized cost is based on the estimates provided by Holcim. The state believes that the $2,293/ton value is generally representative of control costs for the scenario evaluated in this RP analysis.

As a part of their late October 2010 submittals, Holcim provided modeling data for their proposed NO_X RP limitations. The following table lists the projected visibility improvements for NO_X controls, as identified by Holcim:

Holcim Portland Plant – Kiln System		
NOx Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (Δdv)
Maximum (24-hr max) (based on modeled emission rates of 1,363 lb/hr NOx, 586 lb/hr SO_2, 86.4 lb/hr PM_{10})	0.814	N/A
SNCR w/ existing LNB (45% overall NO_X control efficiency) Limits of **2.73 lb/ton** (30-day rolling average) and **2,086.8 tons per year** (based on modeled emission rates of 750 lb/hr NO_X, 586 lb/hr SO_2, 86.4 lb/hr PM_{10})	0.526	0.288

For the kiln, the state has determined that SNCR w/existing LNB is the best NO_X control system available with NO_X RP emission limits of 2.73 pounds per ton of clinker (30-day rolling average) and 2,086.8 tons per year (12-month rolling total). The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This RP determination affords the most NO_X reduction from the kiln system (1,098.9 tpy) and contributes to significant visibility improvement.

A complete analysis that further supports the RP determination for the Holcim Portland Plant can be found in Appendix D.

8.5.2.6 RP Determination for Tri-State Generation and Transmission Association's Nucla Facility

The Tri-State Nucla Station is located in Montrose County about 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 RP Determination for Nucla – Unit 4

Limestone injection improvements, a spray dry absorber (SDA) system (or dry FGD), limestone injection improvements with a SDA, hydrated ash reinjection (HAR), and HAR with limestone injection improvements were determined to be technically feasible for reducing SO2 emissions from Nucla Unit 4. Study-level information for HAR systems at Nucla or any other EGU in the western United States were not available for use in evaluating costs. Since the option to install a dry FGD alone (even without improving limestone injection) provides a better estimated control efficiency than a HAR system plus limestone injection improvements, the HAR system was not considered further in this analysis.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Nucla Unit 4 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Limestone Injection Improvements	526	$914,290	$4,161
Spray Dry Absorber (dry FGD)	1,162	$7,604,627	$6,547
Limestone Injection Improvements + dry FGD	1,254	$9,793,222	$7,808

A dry FGD system, or limestone injection improvements plus dry FGD system, were eliminated from consideration by the state as unreasonable during this planning period due to: 1) the excessive costs, 2) that they would require replacement of an existing system and installation of a completely new system (with attendant new capital costs and facility space considerations), and 3) the lack of modeled visibility affects associated with these particular SO2 reductions.

There is no energy and non-air quality impacts associated with limestone injection improvements. For dry FGD, the energy and non-air quality impacts include less mercury removal compared to unscrubbed units and significant water usage.

There are no remaining useful life issues for alternatives as the source will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO2 emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO2 capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed “limestone injection improvements”) was evaluated and determined to not be feasible under certain operating conditions. The system cannot be ‘run harder’ with more limestone to achieve a more stringent SO2 emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO2 system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that the existing permitted SO2 emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

PM10 RP Determination for Nucla – Unit 4

The state has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for Nucla – Unit 4

Selective non-catalytic reduction (SNCR) was determined to be technically feasible for reducing NOx emissions at Nucla Unit 4. SCR is not technically feasible on a circulating fluidized bed coal-fired boiler, and is otherwise not cost-effective, as discussed in Appendix D. With respect to SNCR, however, there is substantial uncertainty surrounding the potential control efficiency achievable by a full-scale SNCR system at a CFB boiler burning western United States coal. The state and Tri-State’s estimates vary between 10 – 40% NOx reduction potential, which correlates to between $3,000 - $17,000 per ton NOx reduced and may result in between 100 to 400 tons NOx reduced per year.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. There are several qualitative reasons that NOx controls may be warranted at Nucla. First, NOx control alternatives may result in between 100 – 400 tons of NOx reduced annually. Second, Nucla is within 100 kilometers in proximity to three Class I areas, depicted in the figure above, and within approximately 115 kilometers to five Class I areas, including Utah's Canyonlands and Arches National Parks. Third, Nucla has a limited, small-scale SNCR system for emissions trimming purposes installed.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Nucla Unit 4 is no control at the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

Additional Analyses of SO2 and NOx Controls for Nucla

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO2 and NOx control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO2 reduction performance, other relevant SO2 control technologies such as lime spray dryers and flue gas desulfurization, and all NOx control options. A final analysis that addresses the state's comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and, if deemed necessary by the state and the source, testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NOx control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts the different SO2 and NOx control scenarios for Nucla. Finally, Tri-State shall propose to the state any preferred SO2 and NOx emission control strategies for Nucla by January 1, 2013.

A complete analysis that supports the RP determination for the Nucla facility can be found in Appendix D.

8.5.2.7 RP Determination for Tri-State Generation and Transmission Association's Craig Facility Unit 3

The Tri-State Craig Station is located in Moffat County about 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively. Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. Craig Units 1 and 2 are subject to BART. Craig Unit 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_X, SO_2,

PM_{10}) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 RP Determination for Craig – Unit 3

Dry FGD Upgrades - As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Craig Unit 3 operates a [lime spray dryer FGD] currently achieving over 80 percent SO2 reduction. The state considers EPA's BART Guidelines relevant to the RP evaluation of Craig Unit 3 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. Tri-State and the Division are not aware of SO_2 scrubber performance additives applicable or commercially available for the Unit 3 SDA system.

- *Use of more reactive sorbent/Increase the pulverization level of sorbent*: The purchase and installation of two new vertical ball mill slakers improved the ability to supply high quality slaked (hydrated) lime. A higher quality slaked lime slurry means a more reactive sorbent. Typically, slakers are not designed for particle size reduction as part of the slaking process. However, the new vertical ball mill slakers are particularly suited for slaking lime that is a mixture of commercial pebble lime and lime fines. Fines are generated at the Craig facility in the pneumatic lime handling system. Therefore, the Division concurs that TriState cannot use a more reactive sorbent or increase the pulverization level of sorbent.

- *Engineering redesign of atomizer or slurry injection system*: Both the slaked lime slurry and recycled ash slurry preparation and delivery systems were redesigned to improve overall performance and reliability. The improved system allows for slurry pressure control at both the individual reactor level and for each slurry injection header level on each reactor. Tri-State notes that consistent control of slurry parameters (pressure, flow, composition) promotes consistent and reliable SO2 removal performance. The Division concurs that with the recent redesign of the slurry injection system and expansion to two trains of recycled ash slurry preparation, no further redesigns are possible at this time.

Therefore, there are no technically feasible upgrade options for Craig Station Unit 3. However, the state evaluated the option of tightening the emission limit for Craig Unit 3 and determined that a more stringent 30-day rolling SO_2 limit of 0.15 lbs/MMBtu represents an appropriate and reasonable level of emissions control for this dry FGD control technology. Upon review of 2009 emissions data from EPA's Clean Air Markets

Division website, the state has determined that this emissions rate is achievable without additional capital investment.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Craig – Unit 3	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.33	
Dry FGD	0.15	0.26
Dry FGD	0.07	0.38

The current SO2 emission limits for Craig 3 are:

- 0.20 lb/MMBtu averaged over a calendar day, to be exceeded no more than once during any calendar month;
- 80% reduction of the potential combustion concentration of SO2, determined on a 30-day rolling average basis
- 2,125 tons/year annual emission limit

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 3: 0.15 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of existing dry FGD controls. An SO2 limit lower than 0.15 lbs/MMBtu would not result in significant visibility improvement (less than 0.2 delta deciview) and would likely result in frequent non-compliance events and, thus, is not reasonable.

PM10 RP Determination for Craig – Unit 3

The State has determined that the existing Unit 3 regulatory emissions limits of 0.013 (filterable PM) and 0.012 lb/MMBtu (PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for Craig – Unit 3

Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Unit 3.

The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 3 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	853	$4,173,000	$4,887
SCR	4,281	$29,762,387	$6,952

SCR was eliminated from consideration due to the excessive cost/benefit ratio.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	NOx Annual Emission Rate (lb/MMBtu)	98^{th} Percentile Impact (Δdv)
Daily Maximum (2^{nd} half 2009)	0.365	
SNCR	0.240	0.32
SCR	0.070	0.79

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.
Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Craig Unit 3 is the following NOx emission rates:

Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of SNCR. To the extent practicable, any technological application Tri-State utilizes to achieve this RP emission limit shall be installed, maintained, and operated in a manner consistent with good air pollution control practice for minimizing emissions. For SNCR-based emission rates at Unit 3, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls with guidance cost criteria discussed in section 8.4 above.

- Unit 3: $4,887 per ton NOx removed; 0.32 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs.

A complete analysis that supports the RP determination for the Craig facility can be found in Appendix D.

8.5.2.8 RP Determination for Public Service Company's Cameo Station

Public Service Company informed the state that the Cameo Station east of Grand Junction, Colorado will be shutdown 12/31/2011, resulting in SO2, NOx and PM reductions of approximately 2,618, 1,140, and 225 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

Chapter 9 Long Term Strategy

The Long-Term Strategy (LTS) is required by both Phase 1 (Reasonably Attributable Visibility Impairment) and Phase 2 (Regional Haze) regulations. The LTS' of both phases are to be coordinated.

This chapter contains:

- LTS requirements;
- An overview of the current Reasonably Attributable Visibility Impairment Long Term Strategies (RAVI LTS), adopted by the Commission in 2004 and subsequently approved by EPA;
- A review of the 2004 RAVI LTS and a SIP revision;
- A Regional Haze LTS; and
- Reasonable Progress Goals for each of the state's 12 mandatory federal Class I areas.

9.1 LTS Requirements

The LTS requirements for reasonably attributable visibility impairment, as described in 40 CFR 51.306, are as follows:

- Submittal of an initial RAVI LTS and 3-year periodic review and revision (since revised to 5-year updates per 40 CFR 51.306(g)) for addressing RAVI;
- Submittal of revised LTS within three years of state receipt of any certification of impairment from a federal land manager;
- Review of the impacts from any new or modified stationary source;
- Consultation with federal land managers; and
- A report to the public and EPA on progress toward the national goal.

The LTS requirements for Regional Haze (RH), as described in 40 CFR 51.308(d)(3), are as follows:

- Submittal of an initial LTS and 5-year progress review per 40 CFR 51.308(g) that addresses regional haze visibility impairment;
- Consult with other states to develop coordinated emission management strategies for Class I areas outside Colorado where Colorado emissions cause or contribute to visibility impairment, or for Class I areas in Colorado where emissions from other states cause or contribute to visibility impairment;
- Document the technical basis on which the state is relying to determine its' apportionment of emission reduction obligations necessary for achieving reasonable progress in each Class I area it affects;
- Identify all anthropogenic sources of visibility impairing emissions;
- Consider the following factors when developing the LTS:
  (1) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
  (2) Emission limitations and schedules for compliance to achieve the RP goal;
  (3) Measures to mitigate the impacts of construction activities;

(4) Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for this purpose;
(5) Source retirement and replacement schedules;
(6) Enforceability of emission limitations and control measures; and
(7) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

The following sections 9.2 and 9.3 address these LTS requirements.

9.2 2004 RAVI Long-Term Strategy

The RAVI LTS was adopted by the Commission in November 2004. It was subsequently approved by EPA in December 2006 and is summarized below.

9.2.1 Existing Impairment

The LTS must have the capability of addressing current and future existing impairment situations as they face the state. Colorado considers that Commission Regulation No. 3, Part B, 5XIV.D ("Existing Impairment") meets this LTS requirement regarding existing major stationary facilities and provides Federal Land Managers (FLMs) the opportunity to certify whether an existing stationary source(s) is likely reasonably attributable to existing visibility impairment and potentially subject to BART. The state believes existing regulations along with strategies and activities outlined below have together provided for reasonable progress toward the national visibility goal under Phase 1 of the visibility protection program. However, a specific requirement associated with the RH rule is found in 40 CFR § 51.306(c) and is intended to bring into harmony the reasonable attribution requirement in place since 1980 and the RH rule. As such, to meet one part of that requirement, the State of Colorado commits to review the long-term strategy as it applies to reasonably attributable impairment, and make revisions, as appropriate, within three years of state receipt of any certification of reasonably attributable impairment from a Federal Land Manager. This is consistent with the current LTS and State Regulation No. 3 noted above. In addition, Regulation 3, Part D, is amended as part of this SIP action to change the current 3 year review cycle to a 5 year cycle to coordinate the RAVI and RH elements together as intended by the RH rule. Elsewhere in this SIP the state has documented measures to be adopted to address the RH element of the rule including BART determinations and strategies identified in Chapter 8- Reasonable Progress.

In a related action, this 5-year update will satisfy Colorado’s requirement for developing emissions estimates from activities on federal lands (Colorado Revised Statute 25-7-105(1)). The state commits to consult with Federal Land Managers to develop a consolidated emissions inventory, which will be brought to the Air Quality Control Commission as part of the 5-year LTS update and then submitted to EPA. After the 2008 emission inventory data submittal, the Consolidated Emission Reporting Rule will be completely replaced by the Air Emissions Reporting Requirements Rule.

Following is a review of the elements contained in the LTS in a chronological order. During the five-year review required by the RH rule, the State of Colorado will add to or revise this section as needed based on any new findings or actions taken related to RAVI notifications delivered to the state by a FLM.

9.2.1.1 Mt. Zirkel Wilderness

The U.S.D.A. Forest Service (USFS) concluded in its July 1993 certification letter to the State of Colorado that visibility impairment existed in the Mt. Zirkel Wilderness Area (MZWA) and local existing stationary sources, namely the Craig and Hayden power stations, contributed to the problem. In 1996 and again in 2001, settlement agreements between various parties and the Hayden and Craig (Units 1 and 2) Generating Stations, respectively, were completed. The state believes significant emission reductions of SO2 and PM effectively address the RAVI in the MZWA associated with the Hayden and Craig (Units 1 & 2) Generating Stations. The state further believes the Hayden and Craig Consent Decrees effectively resolve the certification of impairment brought by the U.S.D.A. Forest Service. The Forest Service indicated its complaint against Hayden and Craig had been satisfied.

9.2.1.2 BART and Emission Limitations

Although RAVI BART determinations were not made by the state regarding Hayden and Units 1 and 2 of Craig generating stations, emission limitations for the two power plants were incorporated into the LTS SIP in August 1996 (Hayden) and April 2001 (Craig Units 1 and 2) and these SIP revisions remain incorporated into the Colorado SIP. The contents of the August 1996 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for Hayden generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference. EPA originally approved this SIP amendment on January 16, 1997. The contents of the April 2001 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for the Craig generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference.

This RH SIP amendment establishes new limits on Hayden Units 1 and 2, and Craig Units 1 and 2, based on a full BART analysis under the current EPA guidelines. Chapter 6 of this SIP (and Appendix C as well as supporting technical support documents) and changes to Regulation No. 3 result in new control requirements for these units to meet BART.

9.2.1.3 Monitoring

It is important to track the effects of the emission changes on visibility and other Air Quality Related Values in and near Mt. Zirkel Wilderness Area and other Class I areas in Colorado. The Division committed in the 2004 LTS SIP amendment to coordinating a monitoring strategy with other agencies and to provide periodic assessments of various monitored parameters in "before" compared to "after" emission reductions periods. Colorado commits to maintain a monitoring strategy and periodically report to the public and the EPA on an annual basis to include trends, current levels and emission changes. In addition periodic emission inventory updates required by the national emissions reporting rule establish a 3-year reporting cycle for emissions updates. Finally, this RH SIP commits to a five year review process established by the RH rule. Through this, the state believes a demonstration of 'before and after emission reductions' will be met.

9.2.1.4 Other Stationary Sources and Colorado Class I Areas and Additional Emission Limitations and Schedules for Compliance

There are no outstanding certifications of Phase I visibility impairment in Colorado. For Regional Haze, Chapters 6 and 8 specifically delineate the comprehensive BART analysis and Reasonable Progress analysis of other sources. In these sections specific additional controls of selected stationary sources are detailed and emission reductions from these are reflected in the Appendices and technical support documents. The state believes the coordination of these added control measures meets the requirements of the LTS showing both emission limitations and schedules for compliance. In regard to any future certification of any RAVI, the state is prepared to respond to any future certifications as per AQCC Regulation No. 3 X1V.D in accordance with the five year limit established in 40 CFR § 51.306(c).

9.2.1.5 Ongoing Air Pollution Programs

In the 2004 LTS SIP revision, the state committed to:

- Continue to attain and maintain the PM10 and PM2.5 standards which will have some effect on improving visibility in pristine and scenic areas;
- Continue to provide technical support to efforts to understand and reduce the Brown Cloud in the Front Range of Colorado. Analysis of Brown Cloud data indicates it improved approximately 28% between 1991 and 2006, and data through 2009 indicates this trend continues as demonstrated in the APCD Annual Air Quality Data reports;
- Continue to stay involved and inform the Colorado Air Quality Control Commission about emissions growth in the Four Corners area;
- Continue to participate in any future work of the Rocky Mountain National Park research effort; and,
- Continue to administer and follow existing regulations of point, area and mobile sources as specified in AQCC regulations.

9.2.2 Prevention of Future Impairment

The LTS must establish mechanisms to address the prevention of future impairment and outline strategies to ensure progress toward the national goal. The 2004 LTS summarized programs and activities providing reasonable progress toward the national goal under the Phase 1 RAVI program. Generally, Colorado considers its NSR and PSD programs meet the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities.

9.2.3 Smoke Management Practices

The LTS requires smoke management practices of prescribed burning be addressed. The 2004 LTS described Colorado's Regulation No. 9 regarding open burning and wildland fire smoke management. As the level and complexity of burning increases the Division committed to continually evaluate its regulatory program for this source of air pollution and surveyed its current activities in the 2004 LTS review. The addition of the Fire Emissions Tracking System (FETS) by the WRAP, FLMs and states allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation 9 to maintain a database of fire related permits and actions - the basis for data entered into the FETS.

9.2.4 Federal Land Manager Consultation and Communication

The state committed to providing for the plans, goals, and comments of the Federal Land Managers during SIP and LTS revisions. The state will provide, at a minimum, the opportunity for consultation with the FLMs at least 60 days prior to any public hearing on any element of the Class I Visibility SIP including LTS revisions and review. In addition the state will publish as part of the SIP process any formal comments received by the FLMs as a result of their review along with a listing of responses the state made in regard to such comments.

9.3 Review of the 2004 RAVI LTS and Revisions

A July 2007 review of the 2004 RAVI LTS concluded that "The Division does not believe extensive and substantive revisions are necessary at this time to ensure reasonable progress toward the national goal under Phase I of the Class I Visibility Protection Program. However, small updates and edits are proposed so this part of the SIP does not become outdated." Appendix A of this SIP document contains this review. The only other changes to this LTS relate to the change in the update period in Regulation 3, as described above in section 9.2.1, and a commitment to utilize the FETS to track fire data as described above in section 9.2.3. The state commits to work with the FLMs to coordinate any changes to the RH/RAVI LTS on the five year cycle required by the regulation. This will include responding to any notification of impairment by the FLMs, providing an opportunity to comment 60 days prior to any public hearing on proposed changes to the RH/RAVI LTS, and to publish the FLM comments and state responses as part of that review process. Appendix B of this document contains the SIP revision for the RAVI LTS.

9.4 Regional Haze Long Term Strategy

The following presents Colorado's Long Term Strategy (LTS) for Regional Haze.

9.4.1 Impacts on Other States

Where the state has emissions reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another state or states, the state must consult with the other state(s) in order to develop coordinated emission management strategies. Colorado has analyzed the output of the initial 2006 PSAT product from the WRAP and determined that emissions from the state do not significantly impact other states' Class I areas. The two largest Colorado visibility impacts are at Canyonlands National Park in Utah and Bandelier National Monument in New Mexico, where Colorado's total nitrate and sulfate contribution are only 1.0% and 0.5%, respectively, of total haze at these Class I areas. This is not a meaningful level of contribution, and all other modeled contributions at other Class I areas are of a smaller magnitude.

Table 9-1 Colorado's Nitrate and Sulfate Impacts at Bandelier and Canyonlands

Mandatory Class I Area	Modeled Visibility Improvement by 2018 [deciviews]	Colorado's Contribution to 2018 Nitrate	2018 Total Nitrate Impacts at CIA	Colorado's Nitrate Contribution to 2018 Haze at CIA	Colorado's Contribution to 2018 Sulfate	2018 Total Sulfate Impacts at CIA	Colorado's Total Sulfate Contribution to 2018 Haze at CIA	Colorado's Total Nitrate & Sulfate Contribution to 2018 Haze at CIA
Bandelier National Monument	0.3	5.1%	6.6%	0.3%	1.2%	15.5%	0.2%	0.5%
Canyonlands National Park	0.5	6.9%	9.5%	0.7%	2.3%	14.8%	0.3%	1.0%

All Colorado Impacts to nearby Class I Areas that exceed 5.0% are shaded in purple. No Colorado 2018 Sulfate Contributions exceeding 5% were indentified.

9.4.2 Impacts from Other States

Where other states cause or contribute to impairment in a mandatory Class I Federal area, the state must demonstrate it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area. Chapter 7 presents modeling information that describes the contribution to visibility impairment in Colorado's Class I areas from other states. Colorado is establishing reasonable progress goals later in this chapter utilizing modeling results presented in Chapter 7, with supporting information in the technical support documents. This demonstration reflects the emission reductions achieved by the controls committed to by other states.

9.4.3 Document Technical Basis for RPGs

The state must document the technical basis (e.g., modeling) on which the state is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area. This is addressed in the Technical Support Document, Chapter 7, and later in this Chapter 9.

9.4.4 Identify Anthropogenic Sources

The state must identify all anthropogenic sources of visibility impairment considered by the state in developing its LTS. Colorado presents comprehensive emission inventories in Chapter 5 and the TSD, and presents emissions control evaluations in Chapters 6 and 8. Chapter 7 and the Technical Support Documents present information about source apportionment for each Class I area in Colorado.

9.4.5 Emission Reductions Due to Ongoing Air Pollution Control Programs

Below is a discussion of ongoing air pollution control programs that reduce visibility impairing emissions throughout Colorado.

Numerous emission reduction programs exist for major and minor industrial sources of NOx, SO2 and particulates throughout the state, as well as in the Denver Metro Area/Northern Front Range region for VOCs, NOx, and particulates from mobile, area, stationary and oil/gas sources, and are contained in the following Colorado Air Quality

Control Commission Regulations:

- Regulation Number 1: Emission Controls for Particulates, Smoke, Carbon Monoxide and Sulfur Oxides
    - In the SIP (includes specific fugitive dust and open burning regulations)
- Regulation Number 3: Stationary Source Permitting and Air Pollutant Emission Notice Requirements
    - Parts A, B,D, F in the SIP or Submitted to EPA for inclusion in the SIP
    - Part C is the Title V program and is delegated by EPA to the state
- Regulation Number 4: New Wood Stoves and the Use of Certain Woodburning Appliances on High Pollution Days
    - Regulation Number 4 is in the SIP. One provision, the Masonry Heater Test Method, is state only. Colorado is waiting for EPA to develop their own test method – the state will adopt it when EPA goes final
- Regulation Number 6: Standards of Performance for New Stationary Sources
    - Part A – Federal NSPS's adopted by the state – EPA has delegated authority to the state to implement; Colorado has requested delegation for the most recent adoptions
    - Part B – state-only NSPS regulations
- Regulation Number 7: Control of Ozone Precursors
    - The majority of Regulation Number 7 for VOC and NOx control is in the SIP or has been submitted for approval into the SIP – these provisions relate to VOC and NOx control measures for the Denver Metro Area/North Front Range 8-hour ozone nonattainment area and are summarized below
- Regulation Number 9: Open Burning, Prescribed Fire and Permitting – state-only
- Regulation Number 11: Motor Vehicle Emission Inspection Program – Parts A-F in the SIP
- Regulation Number 16: Street Sanding Emissions – In the SIP

Some examples of these programs and the visibility-improving emission reductions they achieve are as follows. It is noted as to whether the program is federally enforceable, submitted by the state in an unrelated submittal for inclusion into the SIP, or state-only enforceable.

- Early reductions from BART sources include approximately 24,000 tpy of SO2 from metro Denver power plants, approximately 6,500 tpy of SO2 from the Comanche power plant, and approximately 18,000 tpy of SO2 from the Craig and Hayden power plants – state-only
- Oil and gas condensate tank control regulations for the Front Range region that have achieved approximately 52,000 tpy of volatile organic compounds (VOC) emission reductions by 2007 - in the SIP - with additional projected reductions of 18,000 tpy by 2010 – Submitted for inclusion in the SIP
- Existing industrial engine control regulations for the Front Range region that have achieved NOx and VOC emissions reductions of approximately 8,900 tpy – In the SIP
- Oil and gas pneumatic actuated device control regulations for the Front Range

region that have achieved VOC emission reductions of approximately 8,400 tpy – state-only

- Mobile source emissions controls for VOCs and NOx through vehicle inspection/maintenance and lower volatility gasoline programs for the Front Range region is estimated to reduce emissions by approximately 8,000 tpy by 2011 – Submitted for inclusion in the SIP
- Statewide condensate tank control regulations that have achieved approximately 5,600 tpy of VOCs emission reductions – state-only
- Statewide existing industrial engine control regulations that are estimated to achieve NOx and VOC emissions reductions of approximately 7,100 tpy by 2010 – state-only
- PM10 emission reduction programs in PM10 maintenance areas throughout the state – In the SIP
- Fugitive dust control programs for construction, mining, vehicular traffic, and industrial sources state-wide – In the SIP
- Smoke management programs for open burning and prescribed fire activities statewide – state-only
- Renewable energy requirements that are driving current and future NOx, SO2 and PM emission reductions from coal-fired power plants - Ballot Initiative 37 – by requiring electricity to be obtained from renewable resources – state-only
- Attaining and maintaining the PM10 and PM2.5 standards throughout the state
- Reducing Colorado Front Range Urban Visibility Impairment (Denver's Brown Cloud) by 28% between 1991 and 2006) – state-only
- Reducing Colorado emissions in the Four Corners area (which is upwind of numerous Class I areas in three states) through oil and gas control measures administered by the CDPHE and the Colorado Oil and Gas Conservation Commission, and by working with the Southern Ute Indian Tribe to develop a Title V permitting program and a minor source permitting program – state-only
- Federal mobile source tailpipe exhaust reductions of approximately 55,000 tpy of VOC and NOx emissions by 2020 – gained through fleet turn-over

(Discussion of state-only measures in this Regional Haze SIP is informational only and not intended to make such measures federally enforceable. However, such measures could be included in future SIP revisions if found necessary to meet National Ambient Air Quality Standards or visibility requirements.)

Another comprehensive review of existing and ongoing programs as well as monitoring data and trends is contained in the Colorado Air Quality Control Commission's 2008-2009 Report to the Public available at the following website:

http://www.cdphe.state.co.us/ap/rttplinks.html

As recently as 1995 Colorado had 12 "non-attainment" areas within the state for carbon monoxide, ozone, and/or PM10 health standards. Generally, all of these areas now maintain good air quality. This progress reflects the effects of local, statewide, regional, and national emission control strategies. This clean-up of Colorado's non-attainment areas also benefited Class I visibility conditions to some unknown degree.

In the summer of 2003, the Denver metropolitan area violated the 8-hour ozone standard. EPA designated all or parts of 9 counties in northeastern Colorado as nonattainment for the 1997 8-hour ozone standard, though the nonattainment designation was deferred with the adoption of the Ozone Action Plan by the Colorado Air Quality Control Commission in March 2004 under EPA's Early Action Compact provisions. High concentrations of ground-level ozone during the 2005-2007 period put the nine-county Denver region in violation of the 1997 standard, and the deferred nonattainment designation became effective in November 2007. A detailed plan to reduce ozone was adopted by the Colorado Air Quality Control Commission in December 2008 and submitted to EPA for approval in 2009. This new plan contains additional VOC and NOx emission reduction measures to support achievement of compliance with the 1997 ozone standard by the end of 2010.

The table below shows the designation status for all current and former non-attainment areas.

Table 9-1 REDESIGNATION and PLAN AMENDMENT STATUS REPORT

PM10	Redesignations	Plan Amendments
Aspen	AQCC approved 1/11/01; EPA approved 5/15/03, effective 7/14/03	10-year update: AQCC approved 12/16/10
Canon City	AQCC approved 10/17/96; EPA approved 5/30/00, effective 7/31/00	10-year update: AQCC approved 11/20/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009
Denver	AQCC approved 4/19/01; EPA approved 9/16/02, effective 10/16/02	Plan amendment developed with MOBILE6 to remove I/M from SIP; AQCC approved 12/15/05; EPA approved 11/6/07, effective 1/7/08
Lamar	AQCC approved 11/15/01; EPA approved 10/25/05, effective 11/25/05	None
Pagosa Springs	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Steamboat Springs	AQCC approved 11/15/01; EPA approved 10/25/04, effective 11/24/04	
Telluride	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010

Carbon Monoxide	Redesignations	Plan Amendments
Colorado Springs	AQCC approved 1/15/98; EPA approved 8/25/99, effective 9/24/99	- Amendment to drop oxyfuels approved by AQCC 2/17/00; EPA approved 12/22/00, effective 2/20/01 - Amendment using MOBILE6 to eliminate I/M from SIP and revise emission budget approved by AQCC 12/18/03; EPA approved 9/07/04, effective 11/08/04 - 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Denver	AQCC approved 1/10/00; EPA approved 12/14/01, effective 1/14/02	- Amendment using MOBILE6 to revise emission budgets approved by AQCC 6/19/03; EPA approved 9/16/04, effective 11/15/04 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08
Ft. Collins	AQCC approved 7/18/02; EPA approved 7/22/03, effective 9/22/03	10-year update: AQCC approved 12/16/10
Greeley	AQCC approved 9/19/96; EPA approved 3/10/99, effective 5/10/99	- Amendment using MOBILE6 to revise emission budget & to eliminate oxyfuels from the regulation/SIP & I/M from the SIP approved by AQCC 12/19/02; EPA approved 8/19/05, effective 9/19/05 - 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Longmont	AQCC approved 12/19/97; EPA approved 9/24/99, effective 11/23/99	- Amendment using MOBILE6 to revise emission budget approved by AQCC 12/18/03; EPA approved 9/30/04, effective 11/29/04 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08

Ozone	Redesignations	Plan Amendments
Denver/Northern Front Range	AQCC approved 1-hour redesignation request and maintenance plan 1/11/01; EPA approved 9/11/01, effective 10/11/01 Early Action Compact 8-hour Ozone Action Plan approved by AQCC 3/12/04; EPA approved 8/19/05, effective 9/19/05	- 8-hour OAP updated to include periodic assessments; AQCC approved 12/15/05; EPA approved //0, effective //0 - 8-hour OAP updated 12/17/06 by AQCC to incorporate Reg. 7's 75% oil and gas condensate tank requirements. EPA approved 2/13/08, effective 4/14/08 - Due to 2005-2007 ozone values, Front Range has violated the ozone standard and the nonattainment designation became effective 11/20/07; revised attainment plan approved by AQCC 12/11/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009
Lead	**Redesignations**	**Plan Amendments**
Denver	EPA redesignated Denver attainment in 1984	
Nitrogen Dioxide	**Redesignations**	**Plan Amendments**
Denver	EPA redesignated Denver attainment in 1984	

For larger stationary sources, the state of Colorado considers its New Source Review and Prevention of Significant Deterioration (PSD) programs as being protective of visibility impairment from proposed major stationary sources or major modifications to existing facilities.

9.4.6 Measures to Mitigate the Impacts of Construction Activities

Regulations 1 and 3 are currently part of Colorado's EPA-approved SIP and apply statewide. In part, provisions of Regulation 1 address emissions of particulate matter, from construction activities. Provisions of Regulation 3 cover issuance of permits applicable to sources defined in these regulations and air pollution emission notices required of specified sources. Provisions of Regulation 1, sections III.D.2.b apply to new and existing point and area sources. This section of the regulation addresses fugitive particulate emissions from construction activities. As such the state believes these regulations address common construction activities including storage and handling of materials, mining, haul roads and trucks, tailings piles and ponds, demolition and blasting activities, sandblasting, and animal confinement operations.

Colorado believes point and area sources of emissions from these regulated sources are in part contributing to regional haze in Colorado. Colorado relies on the particulate emission controls specified in Regulation 1 to most directly address these sources of fine and course particles known to have a minor, but measured, impact on visibility in Class I areas of the state. Based on Coarse Mass Emissions Trace Analysis, described in Section 8 of the Technical Support Document for each Mandatory Class I Federal Area in Colorado included in this SIP, the greatest impact from coarse mass related construction in the state is expected in Rocky Mountain National Park. In RMNP slightly over 6% of the total impact on visibility on the 20% worst days is attributed to coarse mass particulate matter from construction activities. All other Class I areas have impacts from construction in the 2 to 3 percent range.

This regulatory provision requires applicable new and existing sources to limit emissions and implement a fugitive emission control plan. Various factors are specified in the regulation under which consideration in the control plan encompasses economic and technological reasonability of the control.

9.4.7 Smoke Management

For open burning and prescribed fire, Colorado believes its smoke management program reduces smoke emissions through emission reduction techniques and is protective of public health and welfare as well as Class I visibility.

Regulation No. 9 (Open Burning, Prescribed Fire, and Permitting) is the main vehicle in Colorado for addressing smoke management and preventing unacceptable smoke impacts. The rule applies to all open burning activity within Colorado, with certain exceptions. Section III specifically exempts agricultural open burning from the permit requirement[45]. Section III.A of the regulation requires anyone seeking to conduct open burning to obtain a permit from the Division. Regulation No. 9 also contains a number of factors the Division must consider in determining whether and, if so, under what conditions, a permit may be granted. Many of these factors relate to potential visibility impacts in Class I areas. A permit is granted only if the Division is reasonably certain that under the permit's conditions that include the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. Colorado's program also maintains an active compliance assistance and enforcement component. In 2005, the Division certified its smoke management program as consistent with EPA's *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998.

Factors considered under Regulation No. 9, include, for example,

- the potential contribution of such burning to air pollution in the area;
- the meteorological conditions on the day or days of the proposed burning;
- the location of the proposed burn and smoke-sensitive areas and Class I areas that might be impacted by the smoke and emissions from the burn;

[45] The Division has determined that agricultural burning is not a significant source of emissions related to regional haze impairment. For example, 2004 estimates from the Division are that only 503 tpy of PM10 were generated from agricultural burning in the entire State of Colorado. See TSD "Agricultural Burning in Colorado, 2003 and 2004 Inventories".

- whether the applicant will conduct the burn in accordance with a smoke management plan or narrative that requires:
    - that best smoke management methods will be used to minimize or eliminate smoke impacts at smoke-sensitive receptors (including Class I areas);
    - that the burn will be scheduled outside times of significant visitor use in smoke-sensitive receptor areas that may be impacted by smoke and emissions from the fire; and
- a monitoring plan to allow appropriate evaluation of smoke impacts at smoke-sensitive receptors.

The regulation requires all prescribed fire permitees to submit an application to the Division. A permit is granted only if the Division's assessment demonstrates that under the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. The Division reviews each permit application and determines if the burn can be conducted without causing unacceptable visibility impacts within Class I areas, as well as other smoke sensitive sites. In addition, the regulation provides for the Division to impose "permit conditions necessary to ensure that the burn will be conducted so as to minimize the impacts of the fire on visibility and on public health and welfare."

Permitted sources are also required to report actual activity to the Division. Depending on the size and type of fire, reporting may be a daily requirement. At a minimum, each year all permitted sources must return their permit forms with information indicating whether or not there was any activity in the area covered by the permit and, if so, how many acres were burned. The Division annually prepares a report on prescribed burning activity and estimated emissions. Reports from 1990 through 2009 are available by contacting the Division.

The regulation requires the draft permit for any proposed prescribed fire rated as having a "high" smoke risk rating be subject to a 30-day public comment period. The notice for the public comment period must contain information relating to the potential air quality and visibility impacts at smoke sensitive receptors, including Class I areas.

The Division's web site contains information about various aspects of Colorado's Smoke Management Program, downloadable forms and instructions, and links. It is also used to contain the notices for public comment periods for the draft permits subject to public comment. It is located at: http://www.cdphe.state.co.us/ap/smoke/

The addition of the Fire Emissions Tracking System (FETS) allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation 9 to maintain a data base of fire related permits and actions - the basis for data entered into the FETS.

9.4.8 Emission Limitations and Schedules for Compliance to Achieve the Reasonable Progress Goal, and Enforceability of Emission Limitations and Control Measures

The emission limitations and compliance schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and Regulation Nos. 3 and 7. Enforceability of the requirements is ensured by codifying these requirements in regulation, inspecting the sources for compliance and initiating enforcement action under EPA-approved compliance regimes, and requiring monitoring, recordkeeping and reporting.

9.4.9 Source Retirement and Replacement Schedules

Source retirement and replacement schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and in Regulation No. 3. Unless otherwise indicated in those chapters or in Regulation No. 3, the state assumes that all other stationary sources will remain in operation through the end of this planning period. For mobile sources, the turnover of the fleet from older, higher-emitting vehicles to newer, lower-emitting vehicles is captured in the emission inventory presented in Chapter 5 – the fleet turn-over rate was developed utilizing EPA-approved methodologies.

9.4.10 Anticipated Net Effect on Visibility

The WRAP has produced extensive analytical results from air quality monitoring, emissions inventories and air quality modeling. These data demonstrate that causes of regional haze in the West are due to emissions from a wide variety of anthropogenic and natural sources, some of which are controllable, some of which are natural, and some of which originate outside the jurisdiction of any state or the federal government and are uncontrollable. Analyses to date consistently show that anthropogenic emissions of haze causing pollutants will decline significantly across the West through 2018, but overall visibility benefits of these reductions will be tempered by emissions from natural, international, and uncontrollable sources.

Colorado in this RH SIP addresses projections to 2018 anticipating growth and all committed to or reasonably expected controls at the time of modeling (emission inventories for Colorado are presented in Chapter 5). Note that at the time of this 2009 WRAP modeling, Colorado had made BART determinations for each subject to BART unit in 2007 and 2008, and the associated emission reductions were included in the modeling. The inventories indicate a total SO2 emission reduction of 58,907 tons per year and a total NOx emission reduction of 123,497 tons per year by 2018. (SO2 and NOx are the primary emissions addressed by Colorado in this Regional Haze SIP.)

For the uniform rate of progress analysis and to establish Reasonable Progress Goal (RPGs), the modeling results from Chapter 7 are utilized. The modeled Uniform Rate of Progress and the progress made towards URP are presented below. Depending on the Class I area, the state has achieved 36 to 76 percent of the visibility improvement necessary to achieve URP. Note that this analysis does not include emission reductions that result from the BART and RP determinations presented in Chapters 6 and 8.

Figure 9-2 Summary of CMAQ Modeling Progress Towards 2018 URP

Colorado Mandatory Class I Federal Areas

Uniform Progress Summary in Haze Index Metric

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	20% Worst Days					20% Best Days		
	Worst Days Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2018 URP delta from Baseline [dv]	2018 Modeling Projection [dv]	CMAQ Modeling % Towards 2018 URP	Best Days Baseline Condition [dv]	2018 CMAQ Modeling Results [dv]	2018 CMAQ Modeling Below Baseline?
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

Uniform Rate of Progress for 2018

Projected Amount of Progress by 2018 Towards URP

The total tons of visibility impairing pollutants reduced by 2018 due to the BART and RP measures adopted in 2010 are summarized below in Figures 9-4, 9-5 and 9-6.

- 2010 BART: 20,734 tons/year
- 2010 BART alternative: 37,488 tons/year
- 2010 RP: 12,624 tons/year

Total: 70,846 tons/year

The following figures also present "CALPUFF" modeling results that show the visibility benefits of each BART and RP determination. Though not additive to the visibility improvement values presented in Figure 9-2 above because different modeling platforms were used, the CALPUFF modeling illustrates that additional visibility improvement can be anticipated from the BART and RP controls.

Figure 9-3 Emission Reductions Achieved by 2010 BART Determinations

BART Emission Control Analysis

NOx BART - SCR

Source	SCR Capital Costs	Annualized SCR Costs	SCR NOx Reduced [tpy]	SCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Hayden - Unit 2	$ 71,780,853	$ 12,321,491	3,032	$ 4,064	0.82	23 (Zirkel)
Hayden - Unit 1	$ 61,938,167	$ 10,560,612	3,120	$ 3,385	1.12	48 (Zirkel)
Craig - Unit 2 (SCR @ 74% Reduction)	$ 209,552,000	$ 25,036,709	3,975	$ 6,299	0.98	41 (Mt. Zirkel)

NOx BART - SNCR

Source	SNCR Capital Costs	Annualized SNCR Costs	SNCR NOx Reduced [tpy]	SNCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Craig - Unit 1 (SNCR @ 14% reduction)	$ 13,118,000	$ 3,797,000	727	$ 5,226	0.31	15 (Mt. Zirkel)
CEMEX - Kiln	$ 600,000	$ 1,636,636	846	$ 1,934	0.40	14 (RMNP)

NOx BART - Other

Source	Capital Costs	Annualized Costs	NOx Reduced [tpy]	NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Drake - Unit 5 (ULNB w/OFA)	$ 2,895,672	$ 288,844	215	$ 1,342	0.08	> 0 (RMNP)
Drake - Unit 6 (ULNB w/OFA)	$ 3,340,318	$ 337,751	509	$ 664	0.20	> 3 (RMNP)
Drake - Unit 7 (ULNB w/OFA)	$ 4,500,232	$ 461,217	749	$ 616	0.26	> 3 (RMNP)
CENC (TriGen) - Unit 4 LNB, w/SOFA	$ 4,284,900	$ 678,305	214	$ 3,170	0.08	3 (RMNP)
CENC (TriGen) - Unit 5 LNB, w/SOFA and SNCR	$ 6,556,888	$ 1,739,825	354	$ 4,919	0.26	14 (RMNP)
CEMEX - Dryer T5 Permit Limits	$ -	$ -	0	$ -	0.00	none

SO2 BART

Source	Capital or O&M Costs	Annualized Costs	SO2 Reduced [tpy]	SO2 Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Drake - Unit 5: (DSI w/0.26 Emission Limit 30-day)	$ 6,000,000	$ 1,340,663	762	$ 1,761	0.12	2 (RMNP)
Drake - Unit 6: (FGD w/0.13 Emission Limit 30-day)	$ 38,000,000	$ 6,665,771	2,368	$ 2,816	0.24	3 (RMNP)
Drake - Unit 7: (FGD w/0.13 Emission Limit 30-day)	$ 44,166,000	$ 9,577,538	3,764	$ 2,544	0.39	6 (RMNP)
Hayden - Unit 1 Tighten Emission Limit to 0.13	$165,000 parts & $110,000 O&M	$ 141,150	61	$ 2,318	0.01	>12 (Mt. Zirkel)
Hayden - Unit 2 Tighten Emission Limit to 0.13	$165,000 parts & $110,000 O&M	$ 141,150	39	$ 3,629	0.05	>8 (Mt. Zirkel)

TOTAL CAPITAL COST	$ 467,283,031
TOTAL ANNUALIZED COST	$ 74,724,662

TOTAL NOX REDUCED	**13,741**	*tons/year*
TOTAL SO2 REDUCED	**6,993**	*tons/year*
TOTAL COMBINED POLLUTANTS REDUCED	**20,734**	*tons/year*

Figure 9-4 Emission Reductions Achieved by 2010 BART Alternative Determinations

Facility	NOx Emissions Average 2006-2008 (tpy)	NOx Emissions from Alternative (TPY)	Total NOx Emissions Reduced (TPY)	SO2 Emissions Average 2006 -2008 (tpy)	SO2 Emissions from Alternative (TPY)	Total SO2 Emissions Reduced (TPY)
Arapahoe						
Unit 3	1,770	0		925	0	
Unit 4	1,148	900[46]		1,765	1.28	
Cherokee						
Unit 1	1,556	0		2,221	0	
Unit 2	2,895	0		1,888	0	
Unit 3	1,866	0		743	0	
Unit 4	4,274	2,063[47]		2,135	7.81[48]	
Valmont	2,314	0		758	0	
Pawnee	4,538	1,403[49]		13,472	2,406[50]	
Totals	20,361	4,366	15,995	23,908	2,415	21,493

Total Emission Reductions Achieved: 37,488 tons per year

[46] Includes 300 tpy NOx for offset or netting purposes and 600 tpy NOx from firing Arapahoe 4 on natural gas as a peaking unit.

[47] Includes 500 NOx tpy for offset or netting purposes and emissions at 0.12 lb NOx/MMBtu

[48] Emissions at 0.0006 lb SO2/MMBtu

[49] Emissions at 0.07 lb NOx/MMBtu

[50] Emissions at 0.12 lb SO2/MMBtu

Figure 9-5 Emission Reductions Achieved by 2010 RP Determinations

RP Emission Control Analysis

NOx RP - SCR

Source	SCR Capital Costs	Annualized SCR Costs	SCR NOx Reduced [tpy]	SCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement

NOx RP - SNCR

Source	SNCR Capital Costs	Annualized SNCR Costs	SNCR NOx Reduced [tpy]	SNCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Craig - Unit 3 (SNCR @ 15% Reduction)	$ 13,139,000	$ 4,173,000	854	$ 4,886	0.32	6 (Mt. Zirkel)
Holcim Cement (establish limit)	not estimated	$ 2,520,000	1,028	$ 2,451	0.23	5 (GSDNP)

NOx RP- Other

Source	Capital Costs	Annualized Costs	NOx Reduced [tpy]	NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	861	n/a	n/a	n/a
Cameo - Unit 1 (Shutdown)	n/a	n/a	516	n/a	n/a	n/a
Cameo - Unit 2 (Shutdown)	n/a	n/a	624	n/a	n/a	n/a
CENC - Boiler 3 (none)	n/a	n/a	n/a	n/a	n/a	n/a
Nixon - Unit 1 (ULNB w/Overfire Air)	$ 3,822,000	$ 970,000	707	$ 1,372	0.15	2 (RMNP)
Nucla (none)	n/a	n/a	n/a	n/a	not modeled	not modeled
Rawhide - Unit 1 (enchanced combustion control)	$ 1,180,000	$ 288,450	448	$ 644	0.35	18 (RMNP)

SO2 RP

Source	Capital Costs	Annualized Costs	SO2 Reduced [tpy]	SO2 Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	1,457	n/a	n/a	n/a
Cameo - Unit 1 (Shutdown)	n/a	n/a	849	n/a	n/a	n/a
Cameo - Unit 2 (Shutdown)	n/a	n/a	1,769	n/a	n/a	n/a
CENC - Boiler 3 (none)	n/a	n/a	n/a	n/a	n/a	n/a
Craig - Unit 3 (tighten existing emission limit)	none	none	0	n/a	0.26	6 (RMNP)
Holcim Cement (establish limit)	not estimated	not estimated	0	n/a	-	n/a
Nixon - Unit 1 LSD @ 0.10 lb/MMBtu (0.11 lb/MMBtu 30-day rolling)	$ 96,160,000	$ 12,036,604	3,215	$ 3,744	0.46	11 (RMNP)
Nucla (none)	n/a	n/a	n/a	n/a	not modeled	not modeled
Rawhide - Unit 1 (no technically feasible options)	n/a	n/a	n/a	n/a	n/a	n/a

PM RP

Source	Capital or O&M Costs	Annualized Costs	PM Reduced [tpy]	PM Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	72	n/a	n/a	n/a
Cameo - Units 1 & 2 (Shutdown)	n/a	n/a	225	n/a	n/a	n/a

TOTAL CAPITAL COST	$ 114,301,000	
TOTAL ANNUALIZED COST	$ 19,988,054	
TOTAL NOX REDUCED	5,038	*tons/year*
TOTAL SO2 REDUCED	7,290	*tons/year*
TOTAL PM REDUCED	297	*tons/year*
TOTAL COMBINED POLLUTANTS REDUCED	12,624	*tons/year*

Of these 70,800 tons of SO2 and NOx reduced due to 2010 BART and RP, approximately 44,500 tons per year were not included in the WRAP's 2009 "CMAQ" modeling. Figure 9-6 below presents this analysis for each of the BART and RP sources.

Figure 9-6 Difference Between the WRAP and Final BART/RP Emissions for NOx and SO2

Additional NOx and SO2 Reductions

Difference between PRP2018b and Proposed BART/RP

PLANT	PRP 2018b NOx [tpy]	2018 BART/RP NOx [tpy]	Difference [tpy]	PRP 2018b SO2 [tpy]	2018 BART/RP SO2 [tpy]	Difference [tpy]
AQUILA, INC. - W.N. CLARK STATION	1,090	-	(1,090)	1,322	-	(1,322)
CEMEX, INC. - LYONS CEMENT PLANT	901	901	-	97	95	(2)
COLORADO SPRINGS UTILITIES - NIXON PLT	2,331	1,650	(681)	4,073	907	(3,166)
COLORADO SPRINGS UTILITIES - DRAKE PLT	3,669	2,789	(880)	2,701	1,590	(1,111)
HOLCIM (US) INC. PORTLAND PLANT	1,859	2,087	228	393	721	328
PLATTE RIVER POWER AUTHORITY - RAWHIDE	3,912	1,418	(2,494)	927	913	(14)
PUBLIC SERVICE CO - CAMEO (shutdown)	-	-	-	-	-	-
PUBLIC SERVICE CO - ARAPAHOE (Unit 3-Shutdown, Unit 4 NG only)	-	900	900	-	1	1
PUBLIC SERVICE CO - VALMONT	2,279	-	(2,279)	879	-	(879)
PUBLIC SERVICE CO CHEROKEE PLT (Units 3 & 4)	5,998	1,813	(4,185)	5,214	8	(5,206)
PUBLIC SERVICE CO CHEROKEE PLT (Units 1 & 2)	4,317	250	(4,067)	1,750	-	(1,750)
PUBLIC SERVICE CO COMANCHE PLT (Units 1 & 2)	6,143	4,602	(1,541)	3,686	2,953	(733)
PUBLIC SERVICE CO COMANCHE PLT (Unit 3)	2,600	2,600	-	3,250	3,250	-
PUBLIC SERVICE CO HAYDEN PLT	7,307	1,341	(5,966)	2,898	2,541	(357)
PUBLIC SERVICE CO PAWNEE PLT	3,942	1,403	(2,539)	2,225	2,406	181
TRI STATE GENERATION CRAIG (Units 1 & 2)	10,974	5,861	(5,113)	2,117	1,952	(165)
TRI STATE GENERATION CRAIG (Unit 3)	5,825	4,839	(986)	1,823	1,863	40
TRI STATE GENERATION NUCLA	1,753	2,167	414	1,325	1,325	0
TRIGEN - COLORADO ENERGY CORPORATION (Units 4 & 5)	1,185	722	(463)	2,624	2,762	138
TRIGEN - COLORADO ENERGY CORPORATION (Unit 3)	159	222	63	170	379	209
	66,243	**35,565**	**(30,678)**	**37,473**	**23,666**	**(13,807)**

Combined Reductions from NOx and SO2 Controls [tpy]: (44,486)

These substantial additional emission reductions will further the amount of progress achieved by 2018.

Colorado believes the combination of WRAP's CMAQ modeling and the Division's BART and RP modeling adequately demonstrate the anticipated net positive visibility benefit or improvement for this SIP. Although the state of Colorado makes no commitment to produce comprehensive RH modeling unless resources are available and there is a need for such analysis (e.g., through the WRAP), it is anticipated in the five year review required by the RH rule and committed to in this SIP that additional regional CMAQ modeling will be done to evaluate compliance with the Reasonable Progress Goals for all the western states.

9.5 Reasonable Progress Goals

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals, for each Class I area in Colorado (expressed in deciviews) that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. The reasonable progress goals (RPGs) must provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

Colorado is relying on the Western Regional Air Partnership's (WRAP's) CMAQ regional modeling performed in 2009 to establish these goals. As stated throughout this chapter, all western states' reasonably foreseeable control measures at the time of modeling were included in the projections of 2018 visibility levels. Colorado determines that the 2018 projections represent significant visibility improvement and reasonable progress upon the state's consideration of the statutory factors, and are the RPGs for each Class I area. Figure 9-7 presents these RPGs.

Figure 9-7 Reasonable Progress Goals for Each Class I Area

Colorado Mandatory Class I Federal Areas

Uniform Progress Summary in Haze Index Metric

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	*20% Worst Days*					*20% Best Days*		
	Worst Days Baseline Condition [dv]	*Uniform Rate of Progress at 2018 [dv]*	*2018 URP delta from Baseline [dv]*	*2018 Modeling Projection [dv]*	*CMAQ Modeling % Towards 2018 URP*	*Best Days Baseline Condition [dv]*	*2018 CMAQ Modeling Results [dv]*	*2018 CMAQ Modeling Below Baseline?*
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

Reasonable Progress Goals for 2018

No Degradation of Visibility for the Best Days

As required, each Class I area must 1) make improvement in visibility for the most-impaired (20% worst) days over the period ending in 2018, and 2) allow no degradation in visibility for the least-impaired (20% best) days. This is demonstrated in Figure 9-5. As stated above in section 9.4.10, these goals reflect the emissions reductions achieved throughout Colorado (as reflected in the Chapter 5 inventories) and the nation. The additional emissions reductions from the BART and RP determinations will increase the amount of progress achieved by 2018.

In establishing the RPGs, the state considered the required four factors as per EPA regulations: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. Colorado describes in Chapter 8 how the four factors were used to select significant sources/source categories not already covered by BART or federal measures for control evaluation. The evaluations resulted in substantial emission reductions that build on the reductions already achieved by other measures.

Although the state used the four factors to determine reasonable and appropriate emission controls for subject facilities, Figure 9-7 illustrates that the RPGs do not achieve URP. The state realizes additional emissions reductions from both within and outside of the state are necessary to achieve URP. The state finds that the RPGs established in this SIP are reasonable for this planning period and that achieving URP in this planning period is not reasonable. In this SIP, Colorado has described, based upon its consideration of the statutory factors, why certain controls for specified BART and RP sources are reasonable, and why additional controls during this planning period are not reasonable. Similarly, the state has described why additional controls for certain area sources (such as oil and gas heater treaters and lean burn RICE engines) are not reasonable in this planning period. The emission reductions needed to achieve URP at each Class I area for this planning period cannot be determined with precision, due to limitations in calculating and modeling all of the visibility-impairing emissions. In the first 5-year assessment, the state commits to begin evaluating this shortfall, first accounting for the degree of additional emission reductions achieved in Colorado and in other states that are not included in the modeling, and then assessing the inventory and modeling technical issues.

Because RPGs are not achieving URP by 2018 and natural conditions by 2064, Colorado is required by the Regional Haze rule to re-calculate and state the length of time necessary to achieve natural conditions, as shown below and presented in Figure 9-8. Instead of achieving natural conditions in 2064 (60 years) at all Class I areas, the year and the length of time is re-calculated as follows:

- Sand Dunes: 2152 (148 years)
- Mesa Verde: 2168 (164 years)
- Zirkel & Rawah: 2106 (102 years)
- Rocky Mountain: 2098 (94 years)
- Black Canyon, Weminuche, & La Garita: 2119 (115 years)
- Eagles Nest, Flat Tops, Maroon Bells & West Elk: 2083 (79 years)

The recalculated natural conditions timeline is based upon progress through 2018, though, as described above, the calculations do not consider the emission control requirements adopted by the state in 2010 and presented in Chapters 6 and 8. The four factors were used to evaluate significant sources of SO2, NOx (and PM from stationary sources) only as the state also determined that it was not reasonable to evaluate sources organic carbon, elemental carbon and particulate matter for control during this planning period. Thus, all reasonable control measures are presented in this SIP and it is acceptable under the Regional Haze rule that natural conditions are projected to be achieved beyond 2064.

Figure 9-8 Re-Calculation of the Length of Time Necessary to Achieve Natural Conditions

Colorado Mandatory Class I Federal Areas

Number of Years to Attain Natural Conditions

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	20% Worst Days										
	Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2064 Natural Conditions [dv]	Total Haze Delta (Baseline-2064 NC) [dv]	Haze Program Period [yrs]	Haze Program Reduction Rate [dv/yr]	2018 Modeling Projection [dv]	2018 Modeling <= 2018 UPG?	Recast Reduction Rate [dv/yr]	Number of years to NC [yrs]	New NC Goal [year]
Great Sand Dunes National Park & Preserve	12.78	11.35	6.66	6.12	60	0.102	12.20	No	0.041	148	2152
Mesa Verde National Park	13.03	11.58	6.81	6.22	60	0.104	12.50	No	0.038	164	2168
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	6.08	4.44	60	0.074	9.91	No	0.044	102	2106
Rocky Mountain National Park	13.83	12.27	7.15	6.68	60	0.111	12.83	No	0.071	94	2098
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	6.21	4.12	60	0.069	9.83	No	0.036	115	2119
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	6.06	3.55	60	0.059	8.98	No	0.045	79	2083

The following figures for Mesa Verde National Park illustrate the re-calculations.

Figure 9-9 Current Uniform Rate of Progress Glidepath for Mesa Verde and the Reasonable Progress Goal for 2018

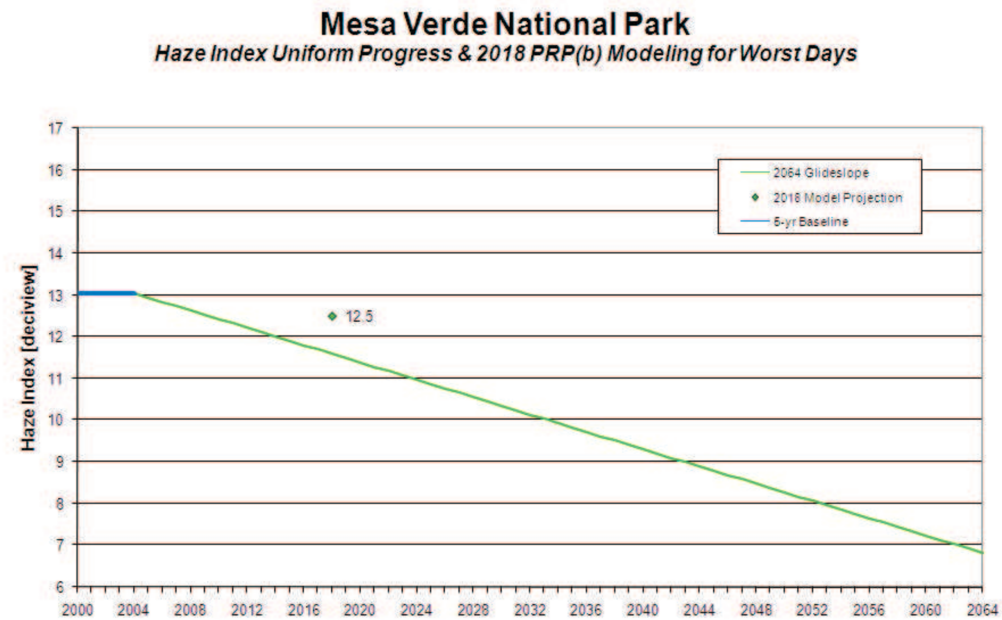
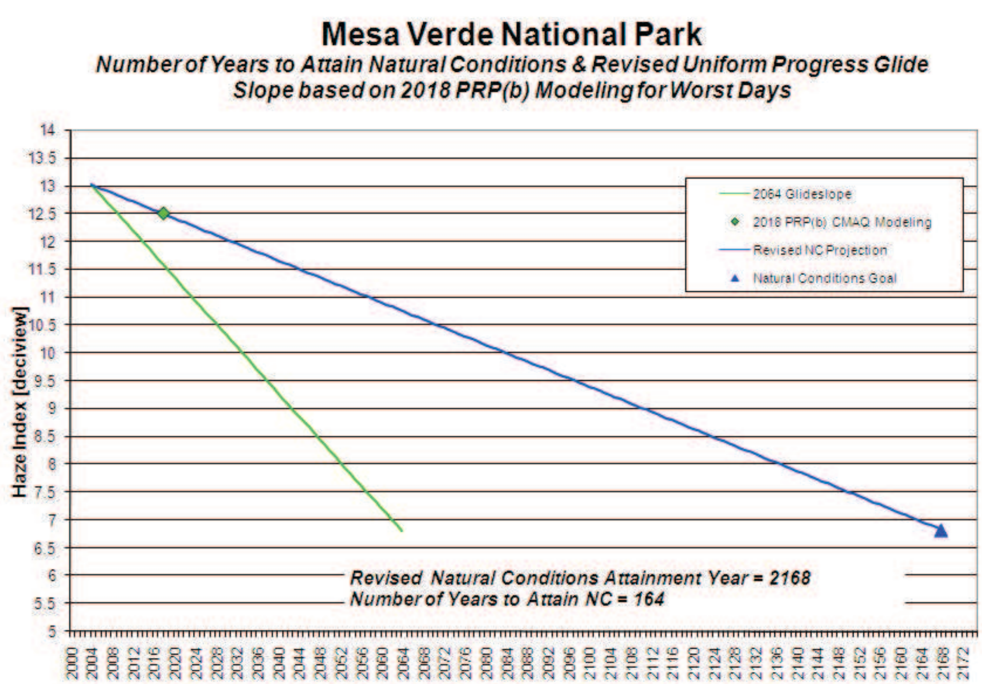


Figure 9-10 Revised Glidepath for Mesa Verde Illustrating the Number of Years to Achieve Natural Conditions



Chapter 10 Commitment to Consultation, Progress Reports, Periodic Evaluations of Plan Adequacy, and Future SIP Revisions

10.1 Future Consultation Commitments

10.1.1 FLM Consultation

As required by 40 CFR 51.308(i)(4), Colorado will continue to consult with the FLM on the implementation of the visibility protection program: and the following items

1. Colorado will provide the FLM an opportunity to review and comment on SIP revisions, the five-year progress reports, and other developing programs that may contribute to Class I visibility impairment. This report will include:
    a. Implementation of emission reduction strategies identified in the SIP as contributing to achieving improvement of worst-day visibility;
    b. Summary of major new source permits issued;
    c. Any changes to the monitoring strategy or monitoring stations that may affect tracking reasonable progress;
    d. Work underway in preparing the five and ten year reviews
2. Colorado will afford the FLM with an opportunity for consultation in person and at least 60 days prior to holding any public hearing on a SIP revision. The FLM consultation must include the opportunity to discuss their assessment of visibility impairment in each federal Class I area; and to provide recommendations on the reasonable progress goals and on the development and implementation of the visibility control strategies. Colorado will include a summary of how it addressed the FLM comments in the revised RH SIP.

10.1.2 Tribal Consultation

Colorado will continue to remain in contact with those Tribes which may reasonably be anticipated to cause or contribute to visibility impairment in Colorado mandatory Class I Federal area(s). For those Tribes that adopted a RH TIP, Colorado will consult with them directly. For those Tribes without a RH TIP, Colorado will consult with both the Tribe and EPA. Documentation of the consultation will be maintained.

10.1.3 Inter-state Consultation/Coordination

In accordance with 40 CFR 51.308(d)(1)(iv) and 51.308(d)(3)(i), Colorado commits to continue consultation with Arizona, Nebraska, Kansas, Wyoming, New Mexico, Utah, and California, and any other state which may reasonably be anticipated to cause or contribute to visibility impairment in federal Class I areas located within Colorado. Colorado will also continue consultation with any state for which Colorado's emissions may reasonable be anticipated to cause or contribute to visibility impairment in those state's federal Class I areas.

With regards to the established or updated goal for reasonable progress, should disagreement arise between another state or group of states, Colorado will describe the actions taken to resolve the disagreement in future RH SIP revisions for EPA's consideration. With regards to assessing or updating long-term strategies, Colorado commits to coordinate its emission management strategies with affected states and will continue to include in its future RH SIP revisions all measures necessary to obtain its share of emissions reductions for meeting progress goals.

10.1.4 Regional Planning Coordination

As per the requirements of [51.308(c)(1)(i)],Colorado commits to continued participation with one or more other States in a planning process for the development of future RH SIP revisions. Future plans will include:

1. Showing of inter-state visibility impairment in federal Class I areas based on available inventory, monitoring, or modeling information as per the requirements of [51.308(c)(1)(ii)].
2. Description of the regional planning process, including the list of states, which have agreed to work with Colorado to address regional haze, the goals, objectives, management, decision making structure for the regional planning group, deadlines for completing significant technical analyses and developing emission management strategies, and a schedule for State review and adoption of regulations implementing the recommendations of the regional group as per the requirements of ; [51.308(c)(1)(iii)].
4. Address fully the recommendations of WRAP, including Colorado's apportionment of emission reduction obligations as agreed upon through WRAP and the resulting control measures required [51.308(c)(1)(iv) and 51.308(d)(3)(ii)].

10.2 Commitment to Progress Reports

40 CFR 51.308(g), requires a State/Tribe to submit a progress report to EPA every five years evaluating progress towards the reasonable progress goal(s). The first progress report is due five years from the submittal of the initial implementation plan and must be in the form of an implementation plan revision that complies with Sections 51.102 and 51.103. At a minimum, the progress reports must contain the elements in paragraphs 51.308(g)(1) through (7) for each Class I area as summarized below.

1. Status of implementation of the RFP SIP measures for CIAs in Colorado and those outside the State identified as being impacted by emissions from within the state
2. Summary of emissions reductions in Colorado adopted or identified as part of the RFP strategy

3. A five year annual average assessment of the most and least impaired days for each CIA in Colorado including the current visibility conditions, difference between current conditions and baseline and change in visibility impairment over the five year period
4. Analysis, by type of source or activity of pollutant emission changes or activities over the five year period from all sources contributing to visibility impairment in Colorado, based on the most recent EI with estimates projected forward as necessary to account for changes in the applicable five year period
5. Assessment of significant changes in anthropogenic emissions in or out of Colorado in the applicable five years which limited or impeded RFP;
6. Assessment of the current SIP sufficiency to meet reasonable progress goals both in Colorado and other States CIA identified as being significantly impacted by Colorado emissions
7. Assessment of Colorado's visibility monitoring strategy and modifications of the strategy as necessary.

In accordance with the requirements listed in Section 51.308(g) of the federal regional haze rule, Colorado commits to submitting a report on reasonable progress to EPA every five years following the initial submittal of the SIP. That report will be in the form of an implementation plan revision. The reasonable progress report will evaluate the progress made towards the reasonable progress goal for each mandatory Class I area located within Colorado and in each mandatory Class I area located outside Colorado, which have been identified as being affected by emissions from Colorado.

The State will also evaluate the monitoring strategy adequacy in assessing reasonable progress goals.

10.3 Determination of Current Plan Adequacy

Based on the findings of the five-year progress report, 40 CFR 51.308(h) requires a State to make a determination of adequacy of the current implementation plan. The State must take one or more of the actions listed in 40 CFR 51. 308(h)(1) through (4) that are applicable. These actions are described below and must be taken at the same time the State is required to submit a five-year progress report.

1. If the State finds that no substantive SIP revisions are required to meet established visibility goals and emissions reductions, the State will provide a negative declaration that no implementation plan revision is needed.
2. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from outside the State, the State shall notify EPA and the other contributing state(s) or tribe(s). The plan deficiency shall be addressed through a regional planning process in developing additional strategies with the planning efforts described in the progress report(s).
3. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from another country, the State shall notify EPA and provide the available supporting information.

4. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from within the State, the State shall revise the plan to address the deficiency within a year.

Colorado commits, in accordance with 40 CFR 51.308(h), to make an adequacy determination of the current SIP at the same time a five-year progress report is due.

10.4 Commitment to Comprehensive SIP Revisions

In addition to SIP revisions made for plan adequacy as specified in Section 10.3 of this plan, 40 CFR 51.308(f)(1-3)requires a State to revise and submit its regional haze implementation plan to EPA by July 31, 2018, and every ten years thereafter. Colorado commits to providing this revision and to evaluate and reassess elements under 40 CFR 51.308(d) taking into account improvements in monitoring data collection and analysis, and control technologies. Elements of the future plans are summarized below.

10.4.1 Current Visibility Conditions

Colorado commits to determine and report current visibility conditions for the most and least impaired days using themost recent five year period for which data is available and to determine the actual progress made towards natural conditions. Current visibility conditions will be calculated based on the annual average level of visibility impairment.

10.4.2 Long Term Strategy Effectiveness

Colorado commits to determine the effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period(s) and to affirm or revise the RPG and monitoring strategy as specified in 10.4.3 and 10.4.4 of this section.

10.4.3 Affirmation of or Revisions to Reasonable Progress Goals

As part of this comprehensive SIP update and future ten year revisions, Colorado commits to affirm or revise the reasonable progress goals in accordance with the procedures set forth in 40 CFR 51.308(d)(1). For any goal which provided a slower rate of progress than needed to attain natural conditions by the year 2064, Colorado will perform the analysis of additional measures that could be adopted to achieve the degree of visibility improvement projected by the analysis contained in the initial implementation plan. This analysis of additional measures will be performed in accordance with the procedures set forth in 40 CFR 51.308(d)(1)(A) to include a consideration of the costs of compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and a demonstration showing how these factors were taken into consideration in selecting the goal.

1. Colorado commits, in accordance with 40 CFR 51.308(d)(1)(B), to analyze and determine the rate of progress needed to attain natural conditions by the year 2064 comparing baseline visibility to natural visibility conditions in each CIA considering the uniform rate of improvement and emission reduction measures needed to achieve RFP.

2. As per 40 CFR 51.308(d)(1)(B)(ii) if Colorado establishes a RPG with a slower rate of progress than needed to attain natural conditions by 2064, Colorado will demonstrate, based on the factors listed in this section 10.4.3, the rate of progress is unreasonable and the established goal is reasonable. Colorado will provide for a public review, as part of the implementation plan revision in 2018, an assessment of the number of years it will take to attain natural conditions based on the RPG.
3. As per 40 CFR 51.308(d)(1(B)(iv) Colorado will consult with States reasonably anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal areas and where Colorado or another State cannot agree a RPG is appropriate, Colorado will describe, in the SIP submittal of 2018, actions taken to resolve disagreements.

Chapter 11 Resource and Reference Documents

There are a substantial number of documents that are referenced in this SIP and form the detailed technical basis for the proceeding Chapters. This Chapter is not the full Technical Support Document. It is a catalog of references used in the preparation of this SIP revision. The full Technical Support Document will be on the Air Pollution Control Division web site at http://www.cdphe.state.co.us/ap/regionalhaze.html

11.1 Class I Area Technical Support Documents (TSDs) TSDs are a comprehensive technical summary for each Class I area in Colorado. The individual Class I area TSDs includes sections describing the Class I area; visibility monitoring; visibility conditions; haze impacting particles; emission source characterization; regional modeling; and PM source apportionment. Included in each TSD is the PSAT Modeling showing estimated source category impacts on Class I areas. Titles include:

Colorado State Implementation Plan for Regional Haze Technical Support Document – Black Canyon of the Gunnison National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Eagles Nest Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Flat Tops Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –La Garita Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document – Maroon Bells Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Mesa Verde National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Mount Zirkel Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Rocky Mountain National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Rawah Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Sand Dunes National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document – Weminuche Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –West Elk Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

11.2 Other Technical Support Documents In addition to the Class I area-specific TSDs, two other technical support documents have been developed. One for the IMPROVE look-alike monitors at Douglas Pass and Ripple Creek and another for agricultural burning in Colorado. Titles are:

Colorado State Implementation Plan for Regional Haze Technical Support Document –Douglas Pass and Ripple Creek Pass Sites, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, June 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Agricultural Burning in Colorado 2003-4 Inventory, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, July 2007

Colorado State Implementation Plan for Regional Haze. Technical Support Document, Analysis of Colorado Visibility Impacts on Nearby Class I Areas, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, March 2007

11.3 Long-Term Strategy Review Update In 2004, the State adopted this SIP revision in order to update the LTS. This SIP revision is intended to amend the 2002 LTS portion of the Class I Visibility SIP. This document is titled:

Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part II Revision of the Long-Term Strategy, Colorado Department of Public Health and Environment, Air Pollution Control Division, November 2004

List of Appendices –

Appendix A – Periodic Review of Colorado RAVI Long Term Strategy

Appendix B – SIP Revision for RAVI Long Term Strategy

Appendix C – Technical Support for the BART Determinations

Appendix D – Technical Support for the Reasonable Progress Determinations

Newark, East (Barnett Shale) Field
Discovery Date – 10-15-1981

- **As of September 28, 2011 there are a total of gas wells 15,306 entered on RRC records.**

In addition, there are 3,212 permitted locations (represents pending oil or gas wells, where either the operator has not yet filed completion paperwork with the Commission, or the completed well has not yet been set up with a Commission identification number)**.**

- Currently, there are 180 commercial disposal wells in the 23-county area. So far in 2011, there have been no new commercial disposal well permits issued.

- This field produces in twenty five (25) counties: Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackelford, Somervell, Stephens, Tarrant, and Wise. In addition, drilling permits have been issued for wells in Hamilton and Young counties.

- Gas Well Gas Production –
  January 2004 through December 2004 = 380 Bcf
  January 2005 through December 2005 = 505 Bcf
  January 2006 through December 2006 = 717 Bcf
  January 2007 through December 2007 = 1,104 Bcf
  January 2008 through December 2008 = 1,612Bcf
  January 2009 through December 2009 = 1,775 Bcf
  January 2010 through December 2010 = 1,847 Bcf
  January 2011 through July 2011 = 1,092 Bcf

- For January through July 2011 production accounts for 31% of Texas Production

- Drilling Permits Issued –
  January 2004 through December 2004 = 1,112
  January 2005 through December 2005 = 1,629
  January 2006 through December 2006 = 2,503
  January 2007 through December 2007 = 3,643
  January 2008 through December 2008 = 4,145
  January 2009 through December 2009 = 1,755
  January 2010 through December 2010 = 2,157
  January 2011 through August 2011 = 1,414

- There are a total of 231 operators in the Newark, East (Barnett Shale) Field.

Top Ten Gas Operators for January through July 2011 as follows:

	Operator Name	Operator No.	Casinghead (MCF)	GW Gas (MCF)	Total Natural Gas (MCF)
1	DEVON ENERGY PRODUCTION CO, L.P.	216378	199,246	264,612,260	264,811,506
2	CHESAPEAKE OPERATING, INC.	147715	0	246,283,399	246,283,399
3	XTO ENERGY INC.	945936	322,942	180,301,876	180,624,818
4	EOG RESOURCES, INC.	253162	18,424,587	104,123,235	122,547,822
5	QUICKSILVER RESOURCES INC.	684830	0	84,432,820	84,432,820
6	CARRIZO OIL & GAS, INC.	135401	0	30,976,622	30,976,622
7	ENCANA OIL & GAS(USA) INC.	251691	28,431	29,876,339	29,904,770
8	RANGE PRODUCTION COMPANY	691703	5,447	19,787,015	19,792,462
9	WILLIAMS PROD. GULF COAST, L.P.	924558	0	19,001,118	19,001,118
10	ENERVEST OPERATING, L.L.C.	252131	0	15,912,812	15,912,812

Rapid photochemical Production of A Ozone at High Concentrations in a Rural Site During Winter

Russ Schnell, Sam Oltmans, and Ryan Neely[1] , Maggie Endres[2], John Molenar[3] and Allen White[1]

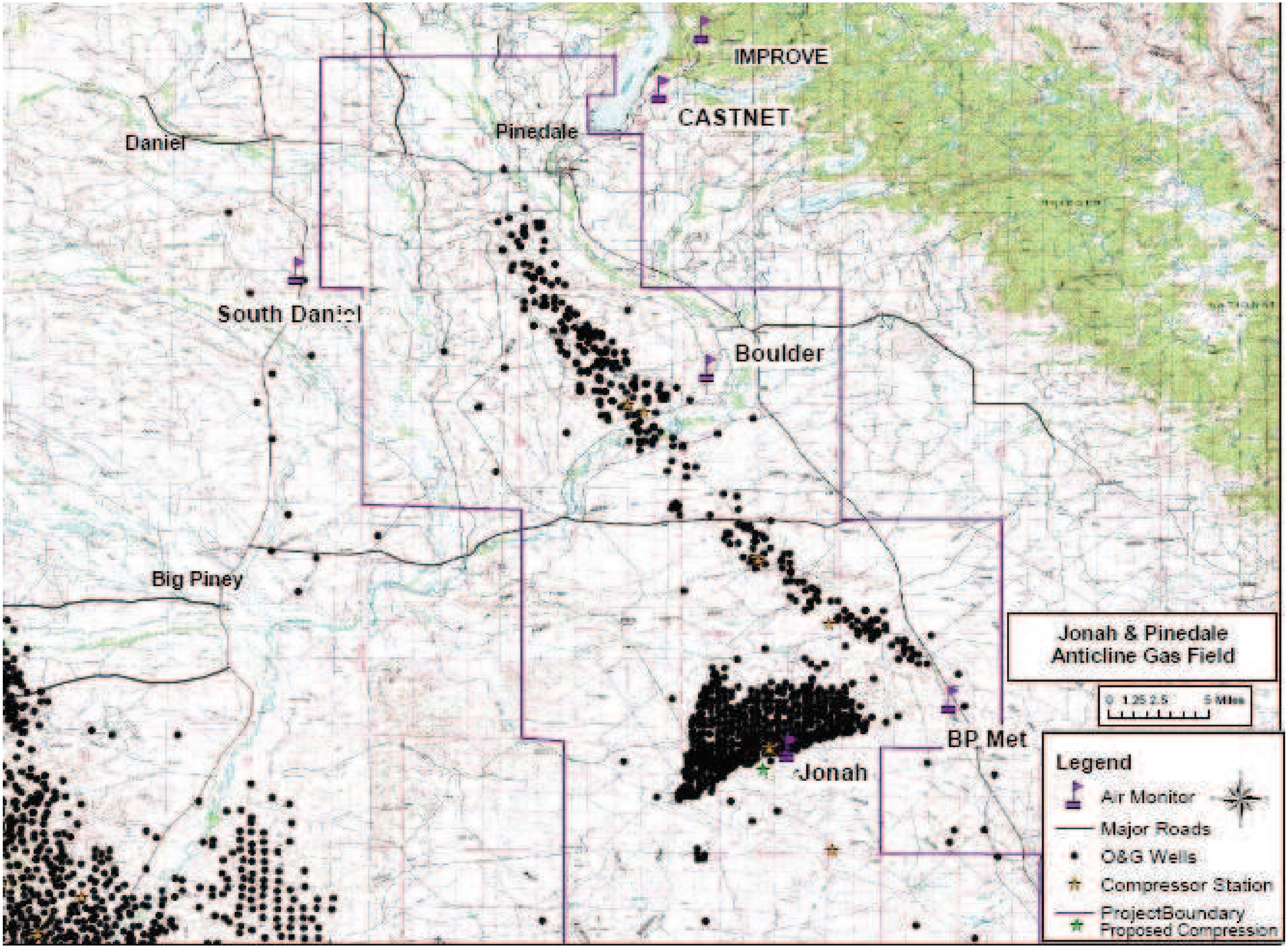
[1]NOAA, Earth System Research Laboratory, Boulder, CO 80305

[2]Wyoming Department of Air Quality, Cheyenne, WY

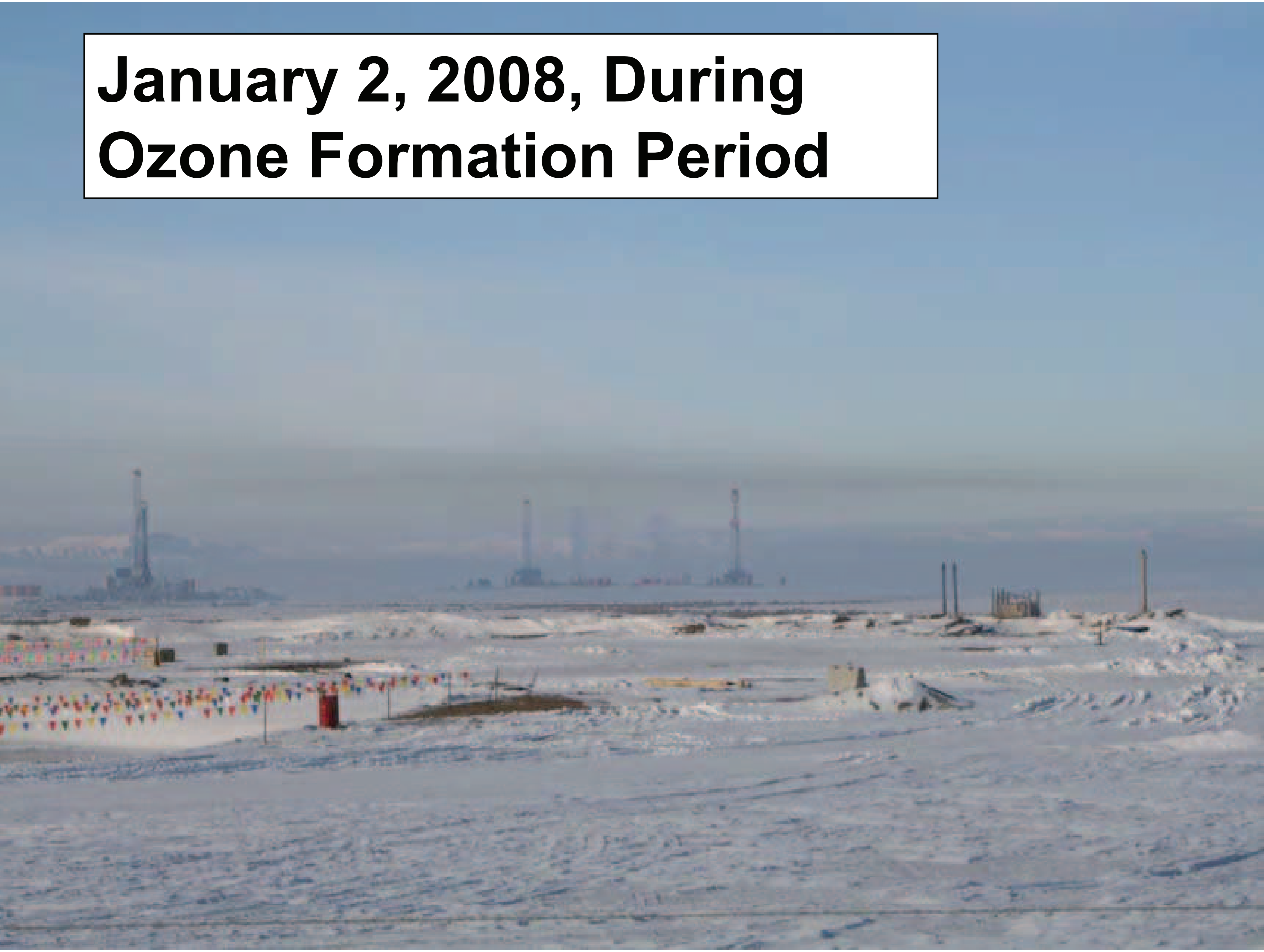
[3]Air Resource Specialists, Fort Collins. CO

My Documents,
Wyoming Ozone

Pinedale Anticline, Jonah, Wyoming

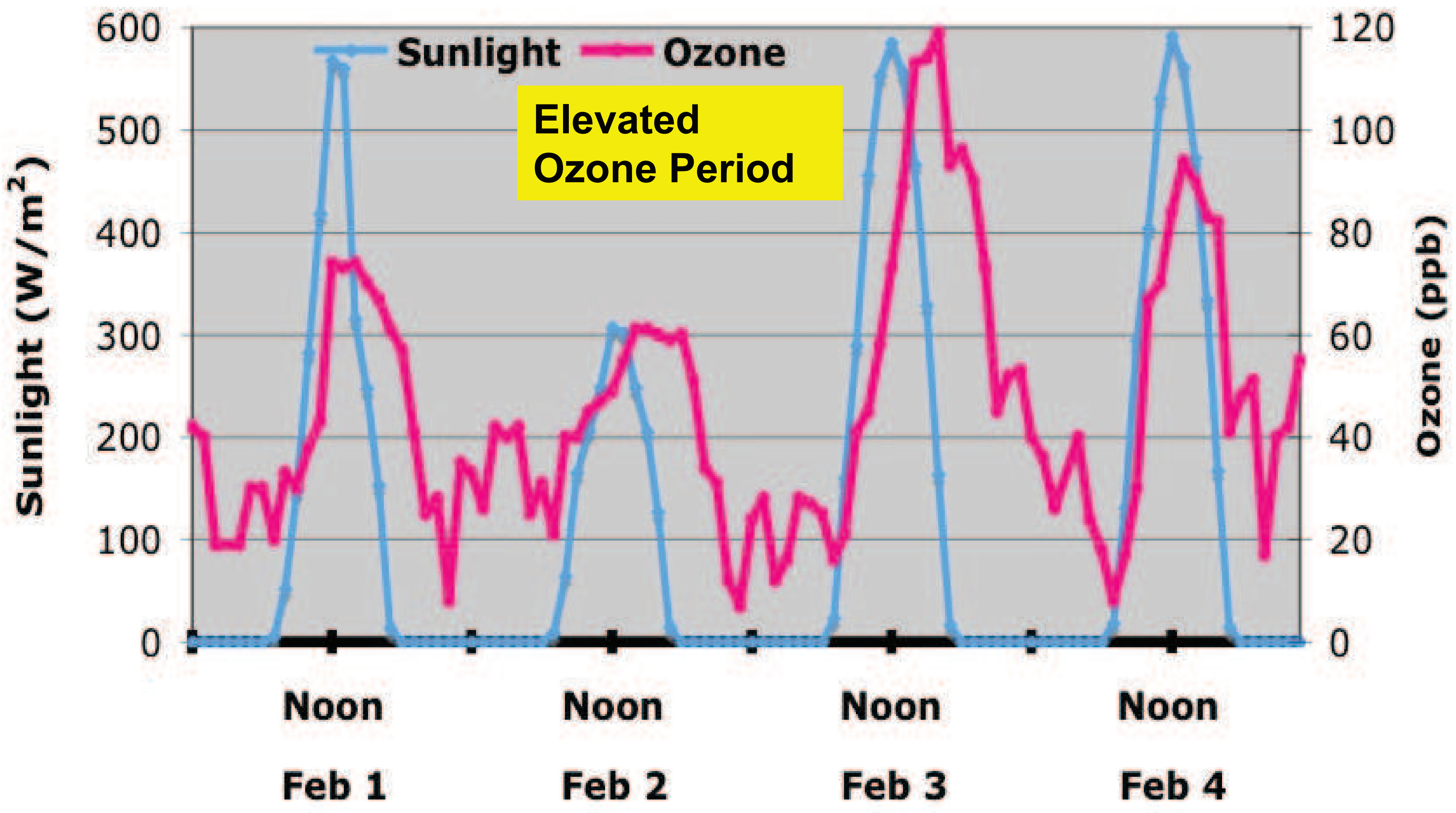



Well Density will increase 300% in 3-5 Years
Blm-5409
Blm-5410
N
W
E
S
© 2006 Navteq
Image © 2006 DigitalGlobe
Google
Pointer 42°27'04.65" N 109°42'12.14" W elev 7237 ft
Streaming |||||||||| 100%
Eye alt 15726 ft

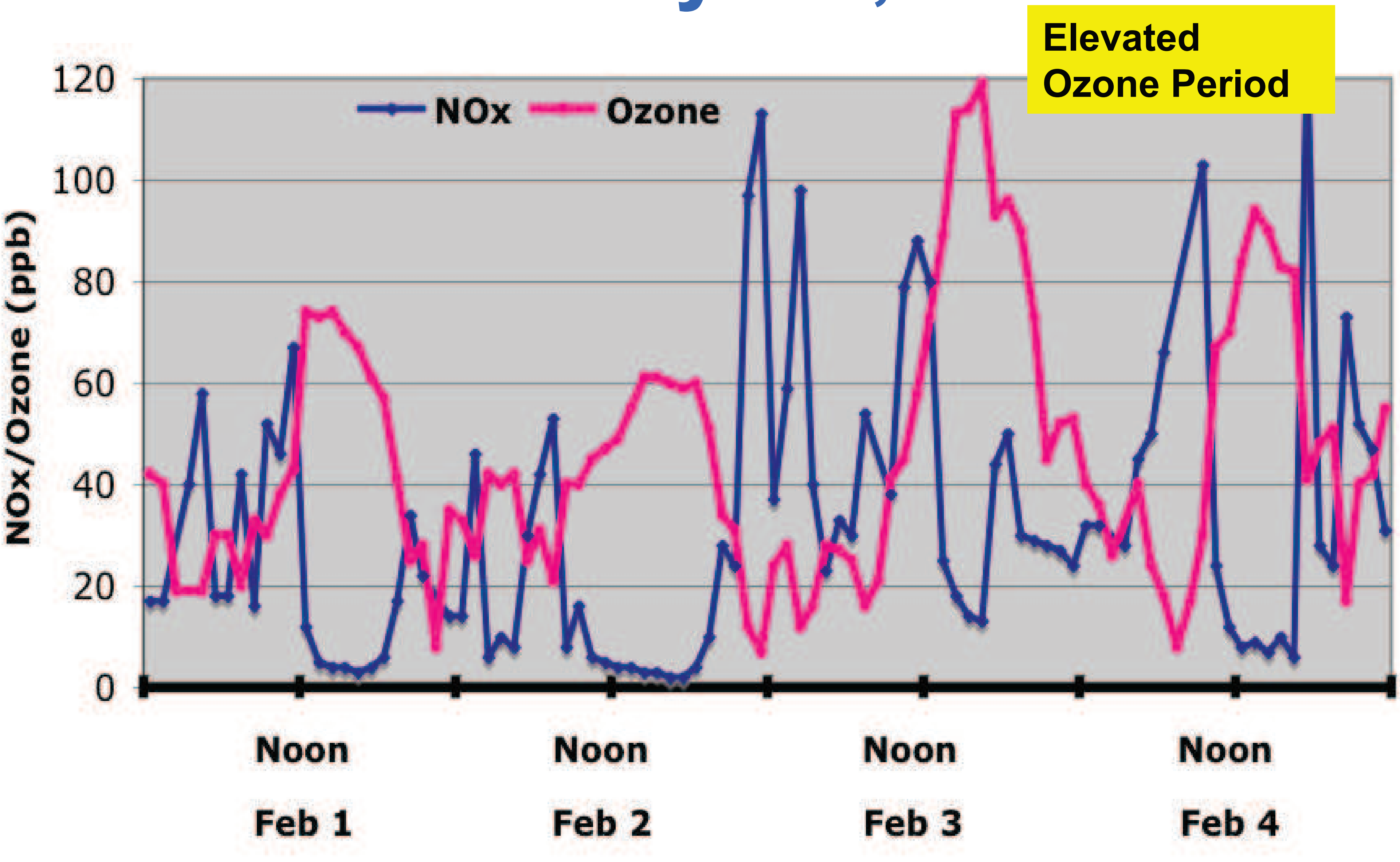


January 2, 2008, During Ozone Formation Period

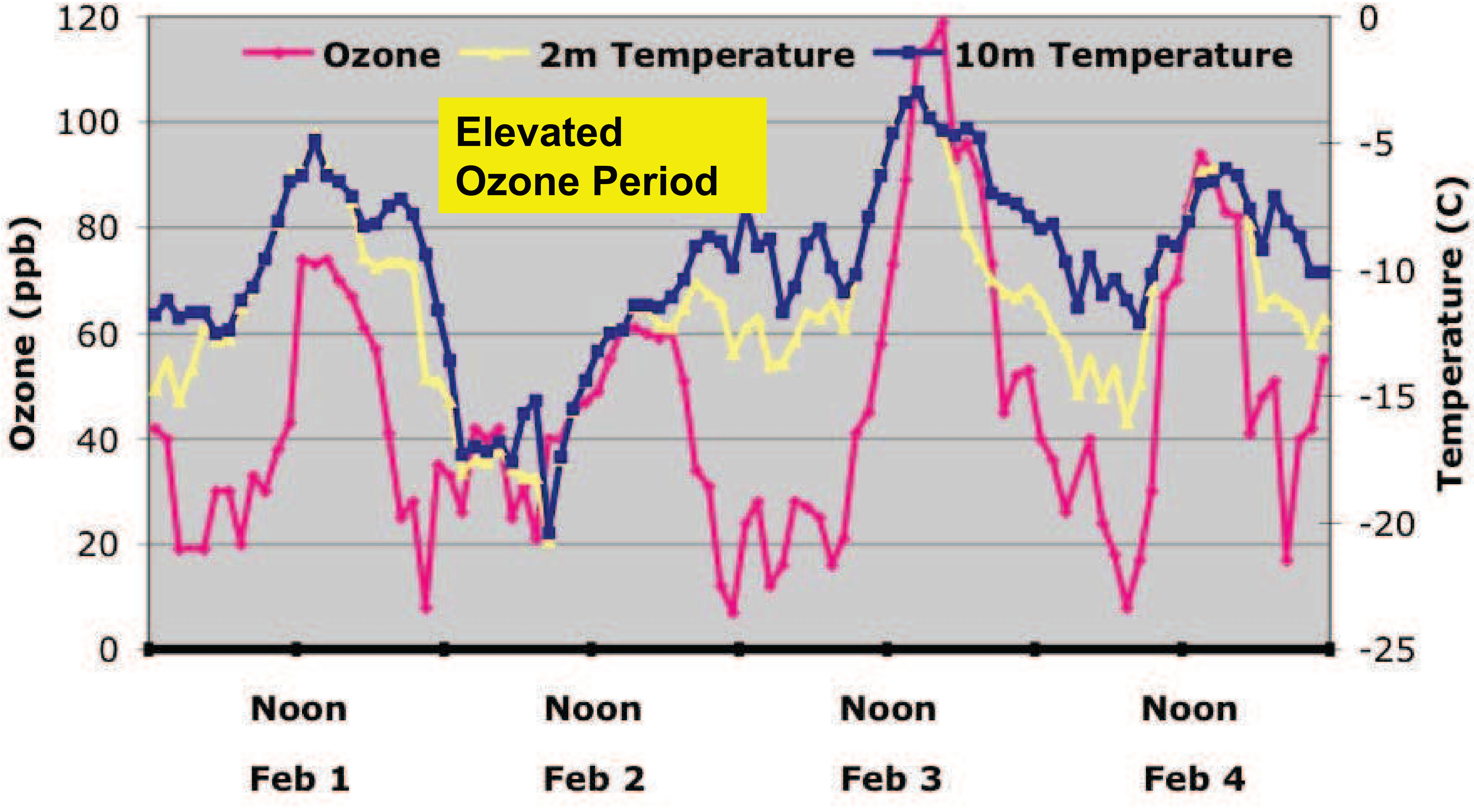
Solar Radiation and Ozone, Jonah, February 1-4, 2005



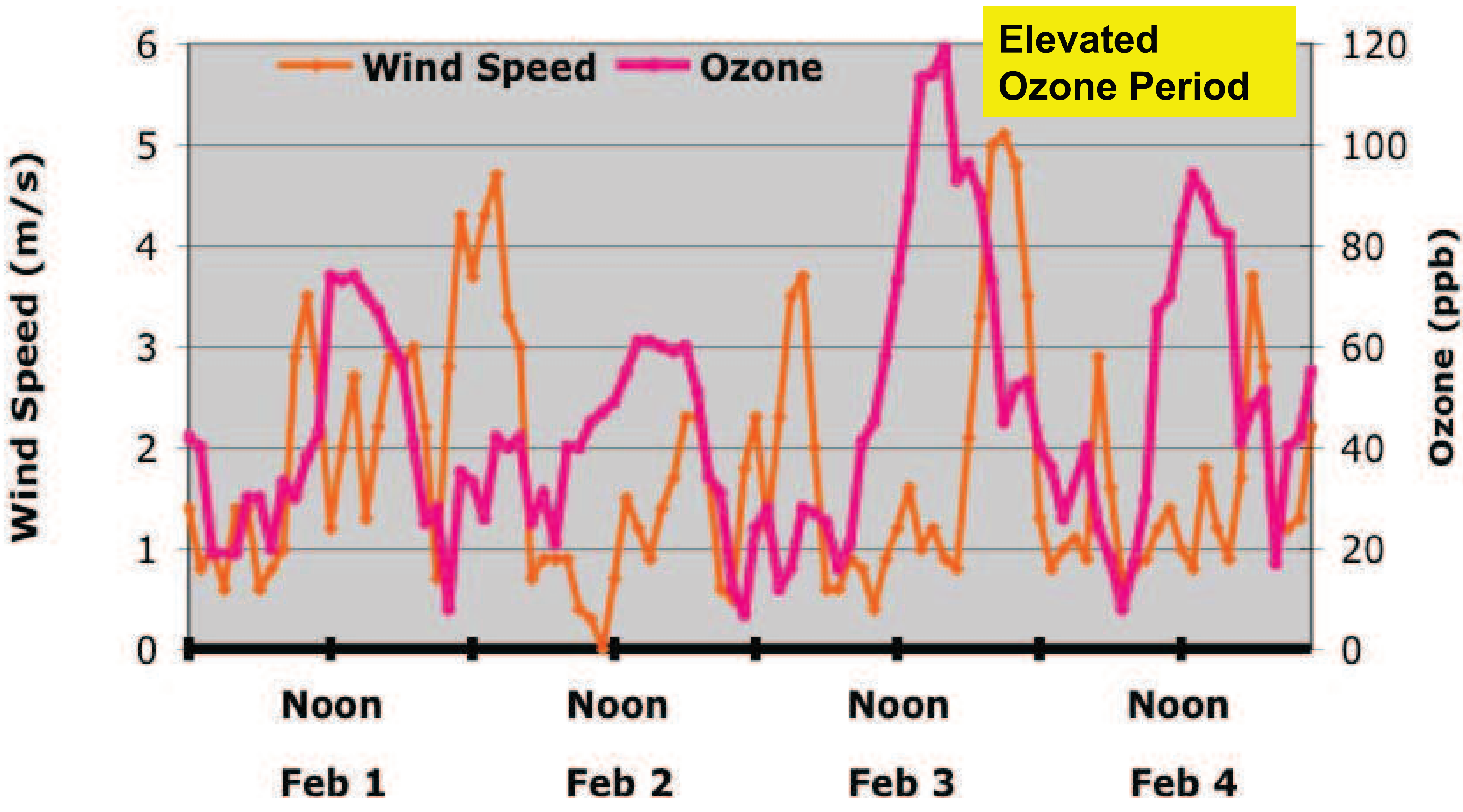
Ozone and NOx, Jonah, February 1-4, 2005



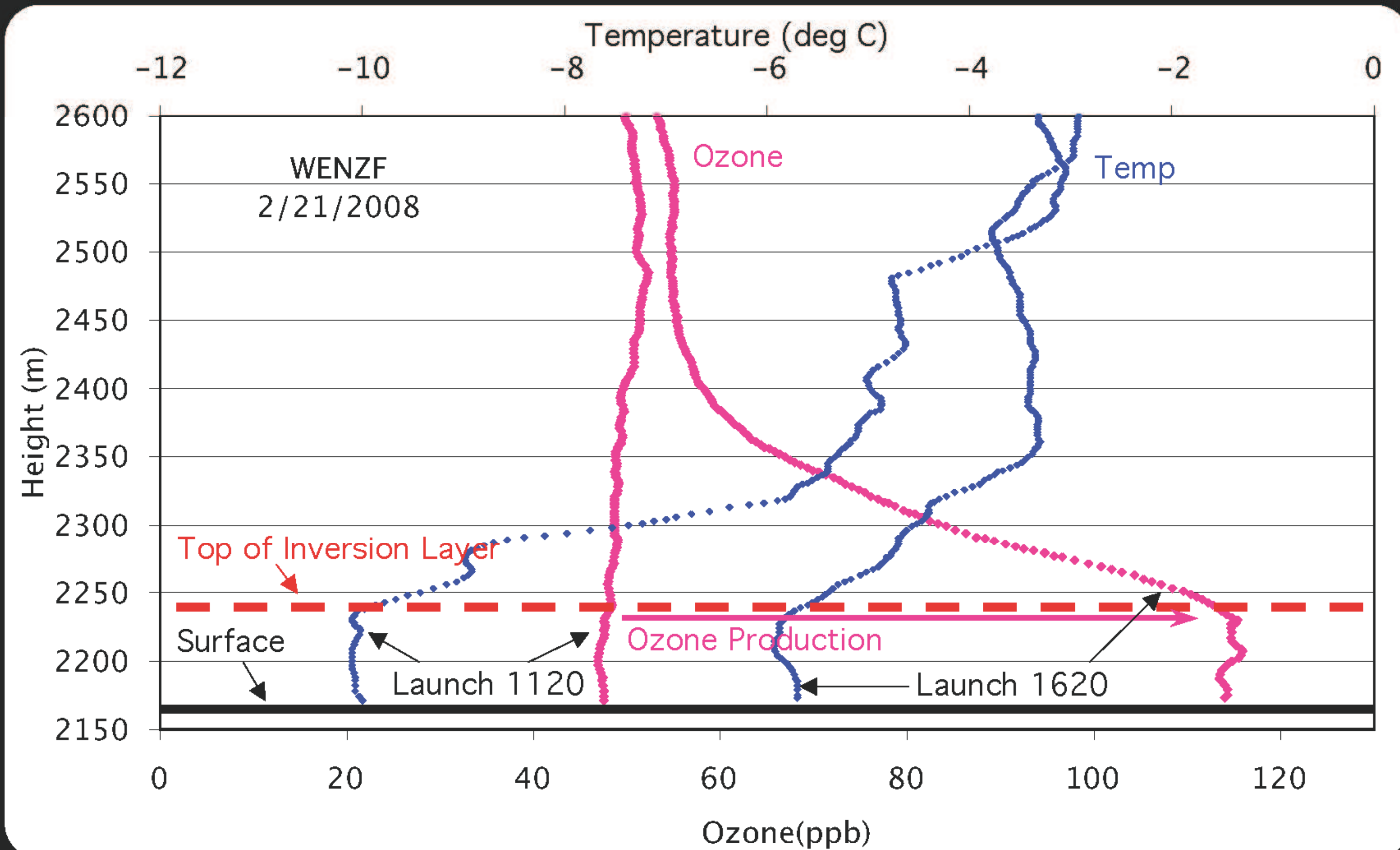
Ozone and Temperature, Jonah, February 1-4, 2005

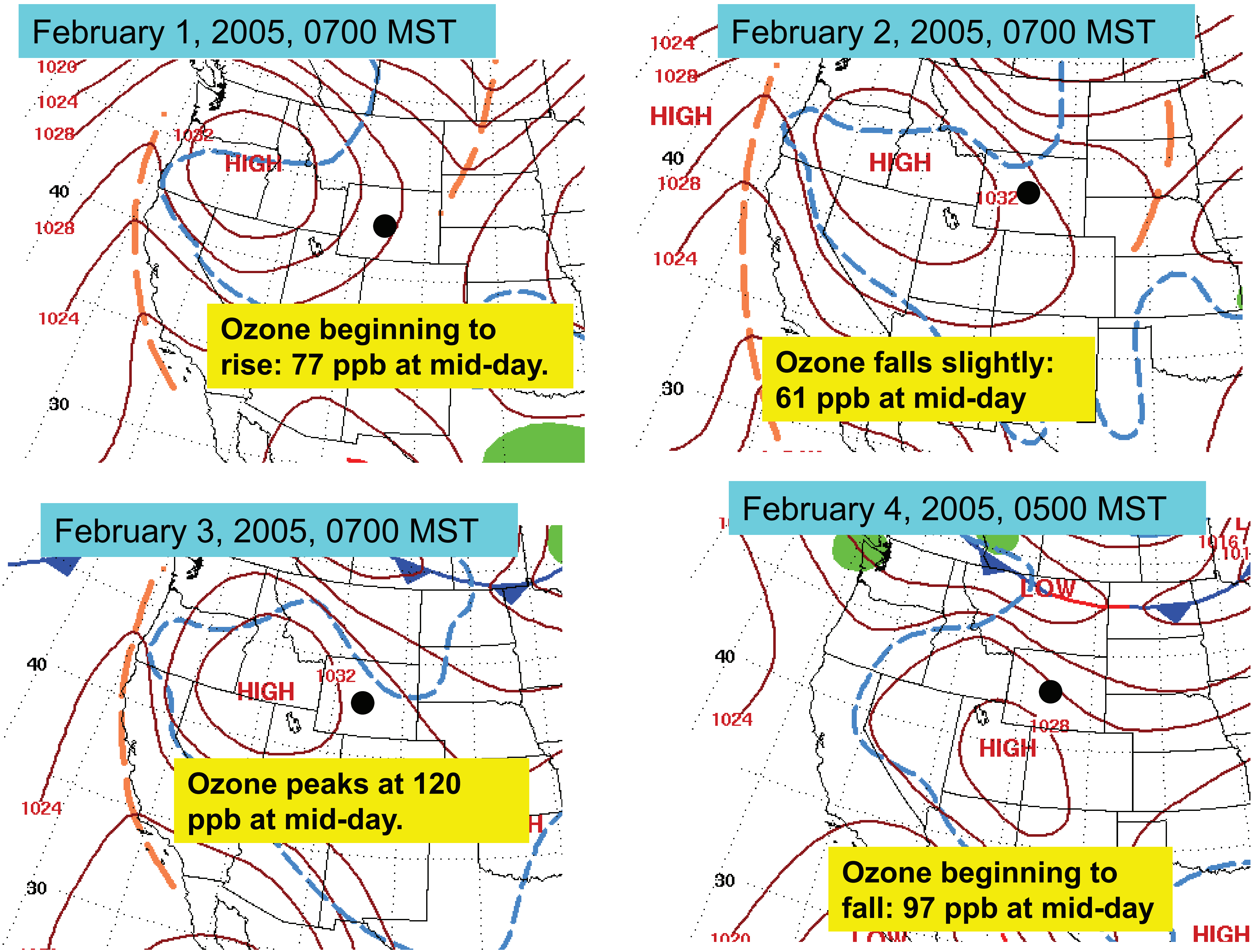


Ozone and Wind Speeds, Jonah, WY, Feb 1-4, 2005



Ozonesondes





February 1, 2005, 0700 MST
1020
1024
1028
1032
HIGH
40
1028
1024
30
Ozone beginning to rise: 77 ppb at mid-day.
February 2, 2005, 0700 MST
1024
1028
HIGH
40
1028
HIGH
1032
1024
30
Ozone falls slightly: 61 ppb at mid-day
February 3, 2005, 0700 MST
40
HIGH
1032
1024
30
Ozone peaks at 120 ppb at mid-day.
February 4, 2005, 0500 MST
1016
LOW
40
1024
1028
HIGH
30
Ozone beginning to fall: 97 ppb at mid-day
HIGH

Economics Of The Jonah Gas Field

- The 30,000 acre Jonah gas field, 30 miles south of Pinedale, Wyoming, is estimated to hold 10 trillion cubic feet of natural gas.
- The field presently produces enough gas to serve 3,000,000 U.S. homes per year.
- In 2007, the Jonah Field produced natural gas revenues in excess of $8 billion.
- The value of the gas to be extracted from the field over 40 years is calculated to be in excess of $60 billion (2005 prices).

Thank You for Hanging In Until the END!

DAVE FREUDENTHAL
GOVERNOR

THE STATE OF WYOMING

STATE CAPITOL
CHEYENNE, WY 82002

Office of the Governor

March 12, 2009

Ms. Carol Rushin
Acting Regional Administrator
USEPA Region 8
Mail Code: 8P-AR
1595 Wynkoop Street
Denver, CO 80202-1129

RE: Wyoming 8-Hour Ozone Designation Recommendation

Dear Ms. Rushin:

This letter transmits my recommendations, as allowed for under Section 107(d)(1) of the Clean Air Act, for Wyoming area designations and nonattainment area boundaries for the new eight-hour ozone National Ambient Air Quality Standards. These recommendations are based on a Wyoming Department of Environmental Quality (WDEQ) staff analysis which follows EPA's guidance dated December 4, 2008, "Area Designations for the 2008 Revised Ozone National Ambient Air Quality Standards."

At this time, I am recommending that all areas of the State of Wyoming be designated as attainment/unclassifiable with respect to the 8-hour ozone standard except for Sublette County and partial sections of Sweetwater and Lincoln counties. Enclosed with this letter is a table listing all specific areas of the state with their corresponding recommended designations, along with a figure showing the boundary of the nonattainment area, and ozone monitoring data collected through 2008.[1] The technical support document, which includes a 9-Factor Analysis, is being sent by the Director of the Department of Environmental Quality under separate cover.

Elevated ozone in a truly rural environment when temperatures are well below freezing is an uncommon event. As we move forward to solve this problem, we are uniquely challenged by the lack of tools available to understand and predict ozone formation in the winter in a valley flanked by the Wind River Mountains.

The State of Wyoming is also challenged by the need to reduce emissions from the natural gas industry which has not traditionally been regulated for ozone nonattainment problems. While the EPA has a long list of control strategies to apply in nonattainment areas, very few of them will

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[1] The recommendation does not extend to lands under the jurisdiction of Tribal Authority.

help to reduce ozone in Sublette County. Lowest Achievable Emissions Rate (LAER), Reasonably Available Control Technology (RACT), major source offsets, transportation control measures, and clean fuels programs are designed to reduce emissions from very large industrial sources and urban traffic which are not present in rural Wyoming. Therefore, the WDEQ has already identified the sources that require controls such as drill rigs, pneumatic pumps, dehydration units, and small heaters.

The State is not waiting for the nonattainment process to unfold to tackle the problem, but is addressing the issue on several fronts:

- Several significant field studies have been initiated to understand the processes leading to the occurrence of high ozone levels and to precisely define meteorological conditions that exist when these ozone events occur. These field operations began in 2007 and have continued through the winter of 2009.

- The AQD has deployed more Federal Reference Monitors in southwest Wyoming.

- DEQ is working with contractors to develop models to replicate the high wintertime ozone concentrations observed in the Upper Green.

- The University of Wyoming is conducting an ozone and precursor sampling program in 2009 to provide an independent perspective and further information on spatial variability of ozone in the Basin.

- The DEQ, the Wyoming Department of Health and the Sublette County Commissioners are working together to assess public health risks posed by air toxics associated with natural gas development. A study is now underway.

- The Air Quality Division has moved aggressively to reduce air pollution by applying BACT to all well sites in the Jonah and Pinedale Anticline gas fields, as well as a minor source offset permitting program. To my knowledge, there isn't another place in the world with this much attention given to permitting natural gas emission points.

I share the outline of our aggressive program for two reasons. First, we believe that the area designations should be based on the technical information painstakingly developed by the DEQ for a unique ozone nonattainment problem. If the EPA uses standard analytic tools appropriate for summertime ozone formation in large metropolitan areas, EPA will reach the wrong conclusions about what causes ozone in Sublette County and how to fix it.

Secondly, I understand that a nonattainment designation includes requirements to reduce air pollution from existing sources. Many local gas producers, working in cooperation with our DEQ, have aggressively reduced air emissions and those reductions will continue even as our natural gas resources continue to be developed. These air emission reductions have occurred because of the application of Wyoming's stringent air pollution permitting requirements; because of industry response to our calls for voluntary emission reductions; and because of Wyoming's insistence on stringent air pollution mitigation requirements in the Jonah Infill and Pinedale Anticline Records of Decision. We have not waited for the federal declaration of nonattainment to solve our air pollution problems, and I do not want a nonattainment designation by EPA to penalize the State for instituting early emission reductions.

While we have submitted recommendations as required under the Act, I envision that much work remains. I would like to propose that my staff at DEQ work with US EPA Region 8 to formalize an approach to share technical information and consult over choices of the baseline EI, the size of the nonattainment area and the resulting classification. Should you have any questions or concerns regarding this matter, please contact Mr. John Corra (307-777-7192) or Mr. Dave Finley (307-777-3746).

Best regards,

Dave Freudenthal
Governor

Enclosures: Attachment 1 - Designation Areas
Attachment 2 - Boundary of Designation Area (Figure)
Attachment 3 - Ozone Monitoring Data

cc: John Corra, DEQ Director
David Finley, AQD Administrator
Lori Bocchino, AQD
Christine Anderson, AQD
Callie Videtich, Director, Air and Radiation Program, EPA Region 8 w/ Enclosures
Monica Morales, EPA Region 8 w/ Enclosures
Kerri Fiedler, EPA Region 8 w/ Enclosures

Attachment 1

2008 Primary and Secondary NAAQS 8-hour Primary and Secondary Ozone Standard
Wyoming Recommendations for Ozone Designations
For areas not under the jurisdiction of Tribal Authority

Region	8-hour Ozone Designation
Casper, WY: Natrona County (part).. The portion within the City of Casper	Attainment/Unclassifiable
Cheyenne, WY: Laramie County (part) .... The portion within the City of Cheyenne	Attainment/Unclassifiable
Evanston, WY: Uinta County (part).. The portion within the City of Evanston	Attainment/Unclassifiable
Gillette, WY: Campbell County (part) .... The portion within the City of Gillette	Attainment/Unclassifiable
Jackson, WY: Teton County (part) .... The portion within the City of Jackson	Attainment/Unclassifiable
Lander, WY: Fremont County (part) .... The portion within the City of Lander	Attainment/Unclassifiable
Laramie, WY: Albany County (part).. The portion within the City of Laramie	Attainment/Unclassifiable
Riverton, WY: Fremont County (part) .... The portion within the City of Riverton	Attainment/Unclassifiable
Rock Springs, WY Sweetwater County (part) .... The portion within the City of Rock Springs	Attainment/Unclassifiable
Sheridan, WY Sheridan County (part) .... The portion within the City of Sheridan	Attainment/Unclassifiable
Albany County (remainder)	Attainment/Unclassifiable
Big Horn County	Attainment/Unclassifiable
Campbell County (remainder)	Attainment/Unclassifiable
Carbon County	Attainment/Unclassifiable
Converse County	Attainment/Unclassifiable
Crook County	Attainment/Unclassifiable
Fremont County (remainder)	Attainment/Unclassifiable
Goshen County	Attainment/Unclassifiable
Hot Springs County	Attainment/Unclassifiable
Johnson County	Attainment/Unclassifiable
Laramie County (remainder)	Attainment/Unclassifiable
Lincoln County (remainder)	Attainment/Unclassifiable
Natrona County (remainder)	Attainment/Unclassifiable
Niobrara County	Attainment/Unclassifiable
Park County	Attainment/Unclassifiable
Platte County	Attainment/Unclassifiable
Sheridan County (remainder)	Attainment/Unclassifiable
Sweetwater County (remainder)	Attainment/Unclassifiable
Teton County (remainder)	Attainment/Unclassifiable
Uinta County (remainder)	Attainment/Unclassifiable

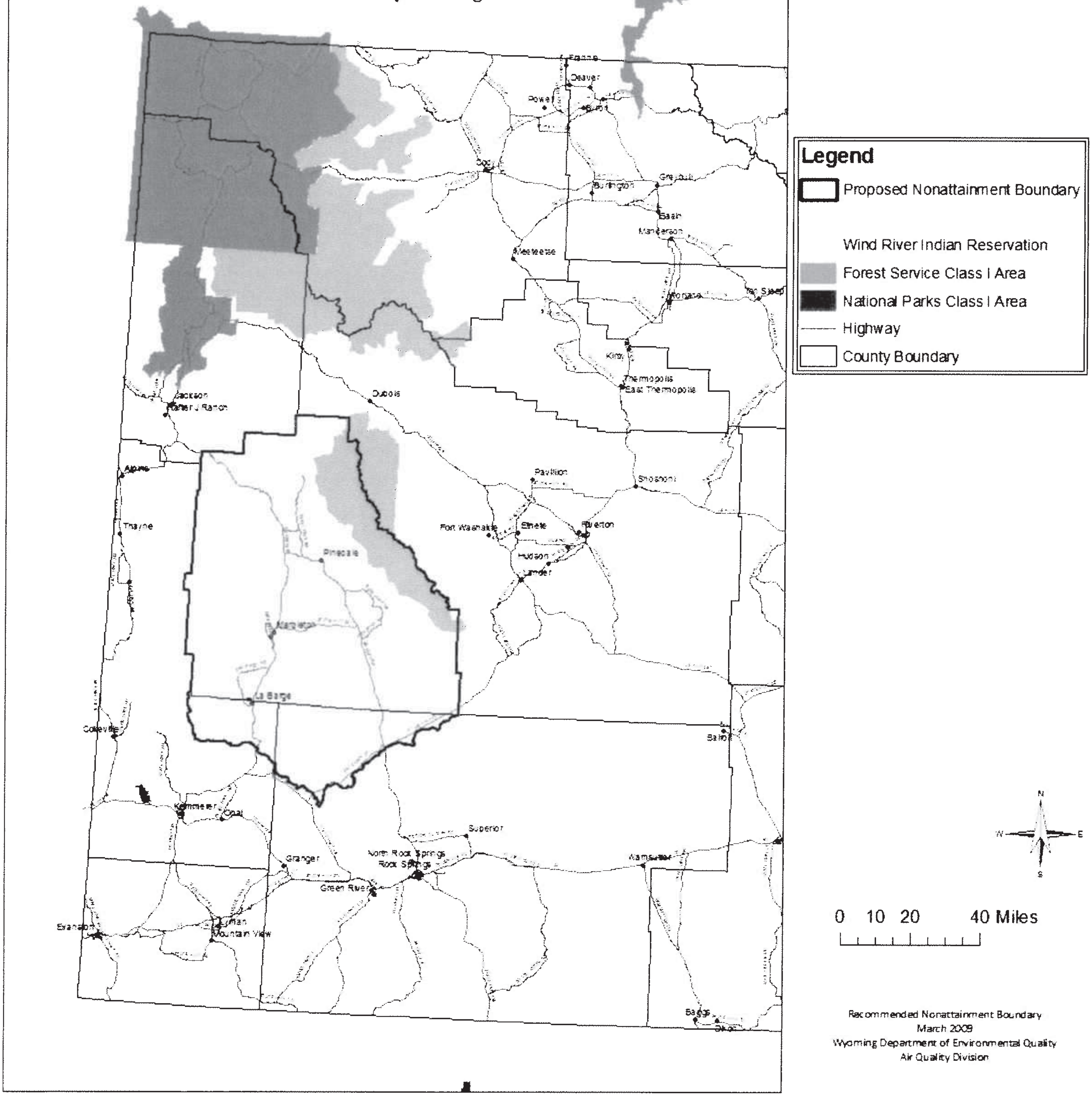
Attachment 1

2008 Primary and Secondary NAAQS 8-hour Primary and Secondary Ozone Standard
Wyoming Recommendations for Ozone Designations
For areas not under the jurisdiction of Tribal Authority

Region	8-hour Ozone Designation
Washakie County	Attainment/Unclassifiable
Weston County	Attainment/Unclassifiable
Upper Green River Basin Area: Sublette County: (all) Lincoln County: (part) The area of the county north and east of the boundary defined by a line starting at the point defined by the intersection of the southwest corner Section 30 Range (R) 115 West Township (T) 27N and the northwest corner of Section 31 R 115 West T 27N of Sublette County at Sublette County's border with Lincoln County. From this point the boundary moves to the west 500 feet to the Aspen Creek. The boundary follows the centerline of Aspen Creek downstream to the confluence of Aspen Creek and Fontenelle Creek (in R 116 W T26N, Section 1). From this point the boundary moves generally to the south along the centerline of Fontenelle Creek to the confluence of Fontenelle Creek and Roney Creek (in R115W T24N Section 6). From the confluence, the boundary moves generally to the east along the centerline of Fontenelle Creek and into the Fontenelle Reservoir (in R112W T24N Section 6). The boundary moves east southeast along the centerline of the Fontenelle Reservoir and then toward the south along the centerline of the Green River to where the Green River in R111W T24 N Section 31 crosses into Sweetwater County. Sweetwater County: (part) The area of the county west and north of the boundary which begins at the midpoint of the Green River, where the Green River enters Sweetwater County from Lincoln County in R111W T24N Section 31. From this point, the boundary follows the center of the channel of the Green River generally to the south and east to the confluence of the Green River and the Big Sandy River (in R109W R22 N Section 28). From this point, the boundary moves generally north and east along the centerline of the Big Sandy River to the confluence of the Big Sandy River with Little Sandy Creek (in R106W T25N Section 33). The boundary continues generally toward the northeast long the centerline of Little Sandy Creek to the confluence of Little Sandy Creek and Pacific Creek (in R106W T25N Section 24). From this point, the boundary moves generally to the east and north along the centerline of Pacific Creek to the confluence of Pacific Creek and Whitehorse Creek (in R103W T26N Section 10). From this point the boundary follows the centerline of Whitehorse Creek generally to the northeast until it reaches the eastern boundary of Section 1 R103W T 26North. From the point where Whitehorse Creek crosses the eastern section line of Section 1 R103W T 26North, the boundary moves straight north along the section line to the southeast corner of Section 36 R103W T27N in Sublette County where the boundary ends.	Non-attainment

R Range, T - Township, N - North, W - West

Attachment 2 - Boundary of Designation Area



Attachment 3

Design Values for Wyoming Ambient Ozone Monitors								
Site Name	AQS ID	Year				3-Year Average 2005-2007 (ppm)	3-Year Average 2006-2008[1] (ppm)
		2005 (ppm)	2006 (ppm)	2007 (ppm)	2008 Q1-Q3[1] (ppm)		
Daniel South	56-035-0100	0.067[2]	0.075	0.067	0.074	N/A	0.072[1]
Boulder	56-035-0099	0.080[3]	0.073	0.067	0.101	0.073[3]	0.080[1]
Jonah	56-035-0098	0.076	0.070	0.069	0.082	0.072	0.074[1]
Yellowstone (NPS)	56-039-1011	0.060	0.069	0.064	0.065	0.064	0.066[1]
Thunder Basin	56-005-0123	0.063	0.072	0.072	0.074	0.069	0.073[1]
Campbell County	56-005-0456	0.063[4]	0.065	0.072	0.060	0.067[4]	0.066[1]

[1] Data collected and validated through 3rd quarter 2008
[2] Incomplete year; began operation in July 2005
[3] Incomplete year; began operation in February 2005
[4] One quarter with less than 75% data completeness

4th Maximum 8-Hour Ozone Values for Ambient Monitors without 3 years of data					
Site Name	AQS ID	Year			
		2005 (ppm)	2006 (ppm)	2007 (ppm)	2008 Q1-Q3[1] (ppm)
Murphy Ridge	56-041-0101	---	---	0.070	0.061
South Pass	56-013-0099	---	---	0.071[2]	0.065
OCI[3]	56-037-0898	---	0.071[3]	0.066	0.072
Wamsutter	56-005-0123	---	0.067[4]	0.064	0.064
Atlantic Rim	56-007-0099	---	---	0.047[5]	0.064

[1] Data collected and validated through 3rd quarter 2008
[2] Incomplete year; began operation in March 2007
[3] Site operated by industry. Incomplete year; began operation in May 2006
[4] Incomplete year; began operation in March 2006
[5] Incomplete year; began operation in October 2007

STATE OF WYOMING

Technical Support Document I
For Recommended 8-Hour Ozone Designation
For the Upper Green River Basin, WY

March 26, 2009

The Wyoming Department of Environmental Quality
Air Quality Division
Herschler Building, 122 West 25th Street
Cheyenne, Wyoming 82002

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EXECUTIVE SUMMARY

In March 2008 the US EPA promulgated a new National Ambient Air Quality Standard (NAAQS) for ozone. The new standard was lowered from 0.08 ppm to 0.075 ppm based on the fourth highest 8-hour average value per year at a site, averaged over three years. Based on monitoring results from 2006 through 2008, the entire state of Wyoming is in compliance with this standard except for at a single monitor, the Boulder monitor, in Sublette County.

The Wyoming Department of Environmental Quality, Air Quality Division (AQD) evaluated whether a nonattainment area should be designated due to the monitored results at the Boulder monitor. Using EPA's guidance in the Robert J. Meyers December 4, 2008 memo, the AQD performed a nine-factor analysis, which is the basis of this document. This analysis supports AQD's recommendation that the Upper Green River Basin (UGRB), as defined in the introduction to this document, be designated as nonattainment for the 2008 ozone NAAQS.

The AQD bases this recommendation on a careful review of the circumstances surrounding the incidence of elevated ozone events. Elevated ozone in the UGRB is associated with distinct meteorological conditions. These conditions have occurred in February and March in some (but not all) of the years since monitoring stations began operation in the UGRB in 2005. Our determination of an appropriate nonattainment area boundary is focused on an evaluation of EPA's nine factors, applied to the first quarter of the year. It is important to evaluate conditions during the first quarter of the year in order to focus on the very specific set of circumstances that lead to high ozone.

The most compelling reasons for the boundary recommendation are based on the meteorological conditions in place during and just prior to elevated ozone events. Elevated ozone episodes occurred in 2005, 2006 and 2008; they were associated with very light low-level winds, sunshine, and snow cover, in conjunction with a strong low-level surface-based temperature or "capping" inversion. The longest such event (February 19-23, 2008), which also resulted in the highest measured ozone of 122 ppb as an 8-hour average at the Boulder station, has been reviewed in detail and summarized in Section 7 of this document. Section 7 demonstrates that sources outside the recommended nonattainment area would not have a significant impact on the Boulder monitor due to the presence of an inversion and very low wind speeds, which significantly limit precursor and ozone transport from sources located outside of the UGRB.

The AQD carefully examined sources of ozone and ozone precursors within Sublette and surrounding counties. When evaluating sources, AQD considered these five of EPA's factors: population density, traffic and commuting patterns, growth rates and patterns, emission data, and level of control of air emissions. Sublette County is a rural county with a population density of two people per square mile; the most densely populated nearby county (Uinta) is also largely rural with a population density of ten people per square mile. As would be expected, the number of commuters into or out of the UGRB is small and does not represent a significant source of precursor emissions. While there is an interstate highway 80 miles south of the Boulder monitor, the attached analysis demonstrates that I-80 traffic is not considered to be a significant contributor of emissions that impact the Boulder monitor during ozone events.

Although population and population growth was not a significant factor, growth in the oil and gas (O&G) industry in Sublette County was considered pertinent. The volume of natural gas produced doubled between 2000 and 2008 in the county; the number of wells completed doubled between 2004 and 2008. Approximately 1,500 well completions were recorded in Sublette County in the last four years. Growth in the oil and gas industry in nearby areas is much slower.

AQD prepared an estimated inventory of emissions for the recommended nonattainment area and the surrounding counties. The inventory showed that approximately 94% of VOC emissions in the UGRB and 60% of NOx emissions are attributable to oil and gas production and development. Of the eleven major sources in the UGRB, all are O&G related. To the north, east and west there are few major sources in counties adjacent to the UGRB. In addition to the major sources, there are numerous minor sources in the UGRB including several concentrated areas of O&G development. Just to the south of the UGRB, there are a few major sources, several minor sources and again, a concentrated area of O&G wells. AQD then used other factors, meteorology, topography, and level of control of emissions, to determine which of the sources to the south of Sublette County should be included in the proposed nonattainment boundary.

The level of control of emissions in the Jonah and Pinedale Anticline Development is very stringent and new oil and gas production units in Sublette County and surrounding counties require permits including Best Available Control Technology (BACT). An interim policy for Sublette County which took effect in 2008 results in a net decrease in emissions of ozone precursors with every permit that is issued. Since stricter controls for O&G are already in place in Sublette County, if O&G sources outside of Sublette County might contribute ozone or ozone precursors to the Boulder monitor, including these O&G sources in the proposed nonattainment area would provide motivation to control these sources.

In evaluating topography, the east, north and west county boundaries are natural boundaries of high mountains. These geographical and jurisdictional boundaries also coincide with population boundaries and emission source boundaries. To the south, the topographical boundaries are less dramatic, but there are rivers, valleys, and buttes that form geographic boundaries near the southern border of Sublette County. Therefore, the AQD considered the county boundary to the north, east and west to be a reasonable boundary based on geography, jurisdictions, emission sources, population and growth.

However, meteorology provided the strongest basis for setting the southern boundary of the proposed nonattainment area. Elevated ozone in the UGRB is associated with distinct meteorological conditions. These conditions have occurred in February and March in some (but not all) of the years since monitoring stations began operation in the UGRB in 2005.

Meteorological conditions in place during and just prior to elevated ozone events provide the most specific data for setting the south boundary. Elevated ozone episodes are associated with very light low-level winds, cold temperatures, sunshine, and snow cover, in conjunction with strong low-level surface-based temperature inversions. Sources outside the recommended nonattainment area would not have a significant impact on the Boulder monitor due to the presence of an inversion and the very low wind speeds, which influence the transport of emissions. Detailed meteorological data collected during intensive field studies shows that emissions from sources south of the recommended nonattainment area are generally carried toward the east and not into the UGRB during or just prior to an ozone episode. Speciated VOC data collected in the UGRB during elevated ozone episodes also has a dominant oil and gas signature, indicating the VOC concentrations are largely due to O&G development activities.

Meteorology and topography indicate that sources outside a southern boundary defined by the Little Sand Creek and Pacific Creek to the east and the Green River and Fontenelle Creek to the west do not contribute to ozone and ozone precursors which could affect the Boulder monitor.

The analysis conclusively shows that elevated ozone at the Boulder monitor is primarily due to local emissions from oil and gas (O&G) development activities: drilling, production, storage, transport, and treating. The ozone exceedances only occur when winds are low indicating that there is no transport of ozone or precursors from distances outside the proposed nonattainment area. The ozone exceedances only occur in the winter when the following conditions are present: strong temperature inversions, low winds, cold temperatures, clear skies and snow cover. If transport from outside the proposed nonattainment area was contributing to the exceedances, then elevated ozone would be expected at other times of the year. Mountain ranges with peaks over 10,000 feet border the area to the west, north and east influence the local wind patterns. Emission sources in nearby counties are not upwind of the Boulder monitor during episodes which exceed the 8-hour ozone standard in Sublette County.

The proposed nonattainment area boundary includes the violating monitor and the sources which are most likely to contribute ozone and ozone precursors to the monitored area. Using this as a boundary will allow the State to focus its resources on the emission sources that contribute to the ozone issue and will allow the State to control the ozone problem in a timely manner.

INTRODUCTION

BACKGROUND AND REGULATORY HISTORY

The U.S. Environmental Protection Agency (EPA) is charged with developing air quality standards for the protection of human health and welfare. EPA is also required to periodically evaluate those standards and revise them if scientific analyses indicate different standards would be more protective of public health and welfare. In March of 2008, EPA promulgated a new National Ambient Air Quality Standard (NAAQS) for ozone. This new standard lowered the 8-hour level of ozone from 0.08 parts per million (ppm) to 0.075 ppm, based on the fourth maximum 8-hour value at a site averaged over three years. Each state must recommend ozone designations no later than March 12, 2009 and final designations must be complete by March 12, 2010.

BASIS FOR TECHNICAL SUPPORT

This technical support document considers nine criteria, or "factors" to make a recommendation for the appropriate location and boundary of a nonattainment area. Those factors are derived from EPA's memorandum issued December 4, 2008, "Area Designations for the 2008 Revised Ozone National Ambient Air Quality Standards." States must submit an analysis of these nine factors, along with a proposed nonattainment boundary, for any areas that are not meeting the federal standard. The nine factors that must be addressed are:

- Air quality data
- Emissions data (location of sources and contribution to ozone concentrations)
- Population density and degree of urbanization (including commercial development)
- Traffic and commuting patterns
- Growth rates and patterns
- Meteorology (weather/transport patterns)
- Geography/topography (mountain ranges or other air basin boundaries)
- Jurisdictional boundaries (e.g., counties, air districts, existing nonattainment areas, Reservations, metropolitan planning organizations (MPOs))
- Level of control of air emissions

RECOMMENDED NONATTAINMENT AREA BOUNDARY

The State of Wyoming recommends that the UGRB, with boundaries described as follows, be designated as a nonattainment area for the 2008 8-hour ozone standard:

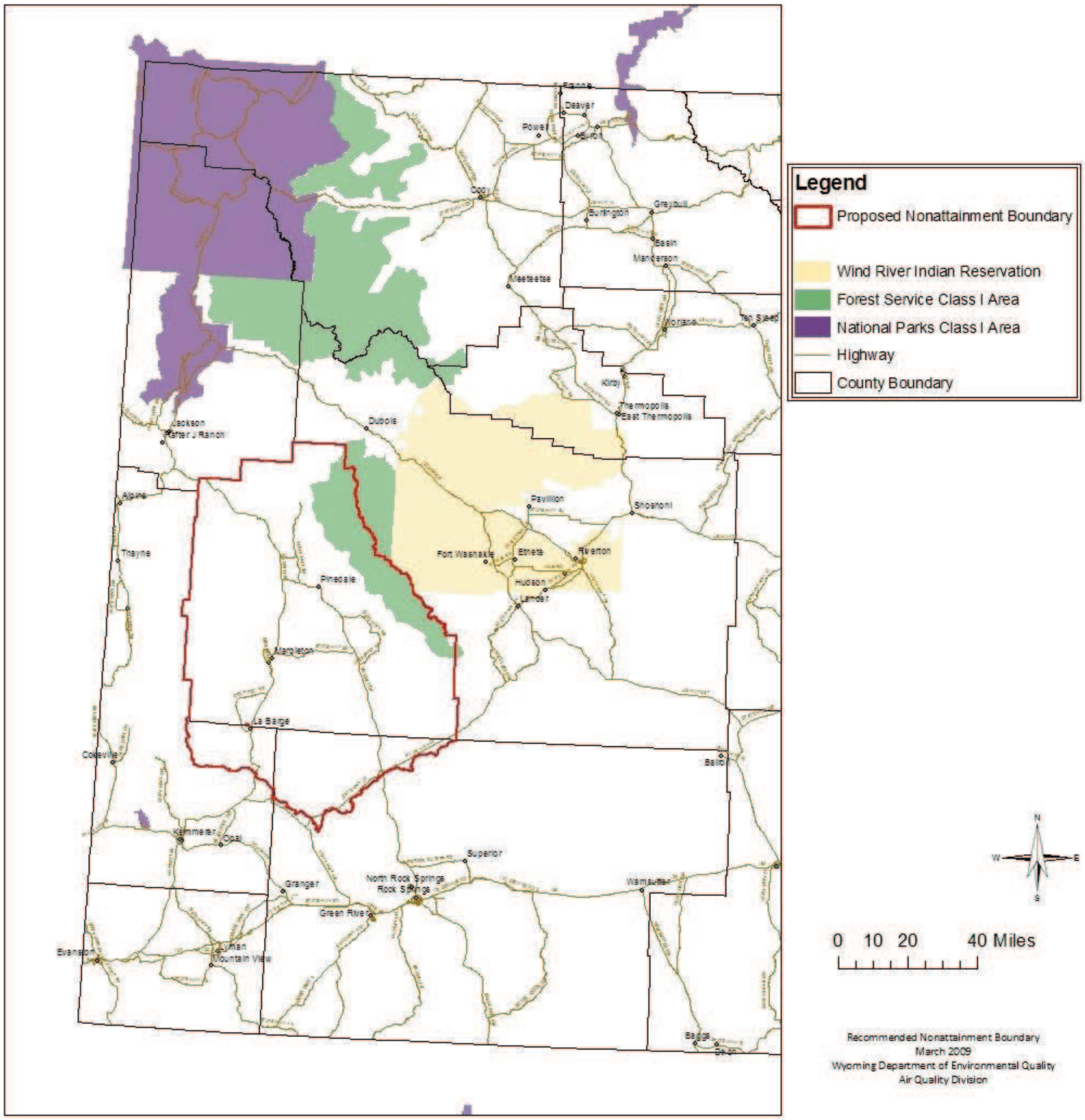
Sublette County: (all)

Lincoln County: (part) The area of the county north and east of the boundary defined by a line starting at the point defined by the intersection of the southwest corner Section 30 Range

(R) 115 West Township (T) 27N and the northwest corner of Section 31 R 115 West T 27N of Sublette County at Sublette County's border with Lincoln County. From this point the boundary moves to the west 500 feet to Aspen Creek. The boundary follows the centerline of Aspen Creek downstream to the confluence of Aspen Creek and Fontenelle Creek (in R 116 W T26N, Section 1). From this point the boundary moves generally to the south along the centerline of Fontenelle Creek to the confluence of Fontenelle Creek and Roney Creek (in R115W T24N Section 6). From the confluence, the boundary moves generally to the east along the centerline of Fontenelle Creek and into the Fontenelle Reservoir (in R112W T24N Section 6). The boundary moves east southeast along the centerline of the Fontenelle Reservoir and then toward the south along the centerline of the Green River to where the Green River in R111W T24 N Section 31 crosses into Sweetwater County.

Sweetwater County: (part) The area of the county west and north of the boundary which begins at the midpoint of the Green River, where the Green River enters Sweetwater County from Lincoln County in R111W T24N Section 31. From this point, the boundary follows the center of the channel of the Green River generally to the south and east to the confluence of the Green River and the Big Sandy River (in R109W R22 N Section 28). From this point, the boundary moves generally north and east along the centerline of the Big Sandy River to the confluence of the Big Sandy River with Little Sandy Creek (in R106W T25N Section 33). The boundary continues generally toward the northeast along the centerline of Little Sandy Creek to the confluence of Little Sandy Creek and Pacific Creek (in R106W T25N Section 24). From this point, the boundary moves generally to the east and north along the centerline of Pacific Creek to the confluence of Pacific Creek and Whitehorse Creek (in R103W T26N Section 10). From this point the boundary follows the centerline of Whitehorse Creek generally to the northeast until it reaches the eastern boundary of Section 1 R103W T 26North. From the point where Whitehorse Creek crosses the eastern section line of Section 1 R103W T 26North, the boundary moves straight north along the section line to the southeast corner of Section 36 R103W T27N in Sublette County where the boundary ends.

A picture of this area follows.



KEY ISSUES

Elevated ozone concentrations in most areas occur during the warm summer months, when there is abundant solar radiation and high temperatures. The elevated ozone concentrations at the Boulder monitor in Sublette County occur in late winter and early spring when sun angles are low so there is less solar radiation and temperatures are below freezing. Ozone formation at the Boulder monitor in Sublette County does not follow the pattern of ozone formation found in urban areas in the summer.

Moderately elevated ozone was first detected in Sublette County in February of 2005 and 2006. The Wyoming Air Quality Division (AQD) conducted intensive meteorological and ambient data collection and analyses in 2007 and 2008 in order to understand this phenomenon. AQD is continuing this effort in 2009. Although analysis of all the data is not complete, AQD has already determined that:

- Local meteorological conditions are the single most important factor contributing to the formation of ozone and the definition of the nonattainment boundary.
- Meteorological models that utilize only regional data will not correctly attribute ozone and ozone precursors to the sources which affect the UGRB.
- Trajectory analyses using detailed observation-based wind field data show that local scale transport of ozone and ozone precursors is dominant during periods of elevated ozone.
- Trajectory analyses using the wind field data show that regional transport of ozone and ozone precursors appears to be insignificant during periods of elevated ozone.

SECTION 1
AIR QUALITY DATA

SYNOPSIS

Ozone at levels exceeding the standard has been monitored at one of three stations in the UGRB – specifically, the Boulder monitor.

Measured ozone levels have not exceeded the standard in the counties adjacent to the UGRB.

Elevated ozone within the UGRB typically only occurs in January, February, or March.

VOCs detected in ambient air in the UGRB have a strong oil and gas signature.

ANALYSIS

The Wyoming Air Quality Division (AQD) operated three monitoring stations in the proposed nonattainment area in 2005-2008. Monitor locations are shown on the map in Figure S.1-1. This map also shows the location of monitors in adjacent counties.

FIGURE S.1-1: Map Showing Monitoring Stations In and Near the Upper Green River Basin

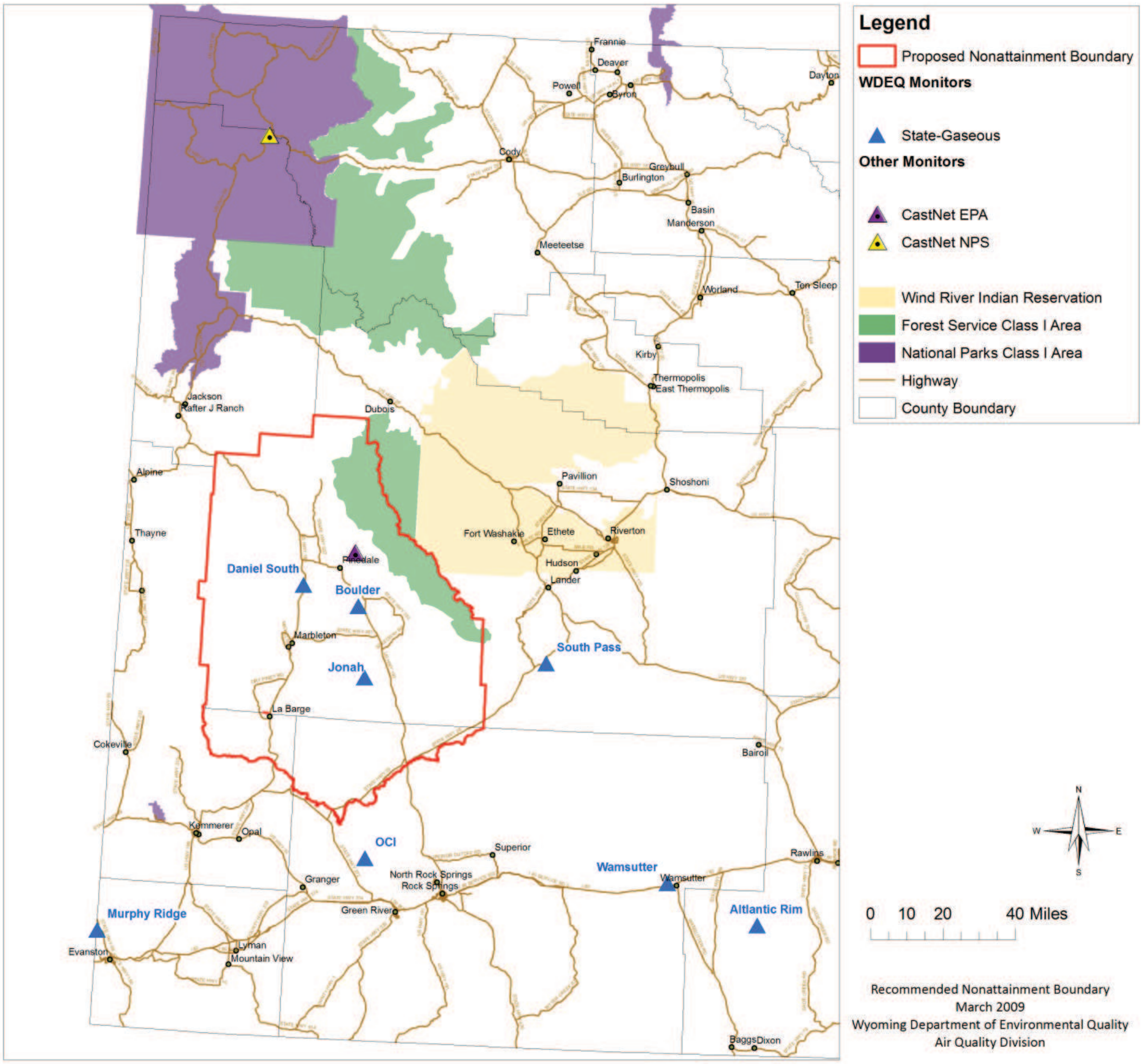


Table S.1-1 shows the ozone design values for the 8-hour standard for the Reference or Equivalent Method monitoring stations shown in Figure S.1-1. All data are collected by Reference or Equivalent Method monitors and meet EPA's criteria for quality and completeness unless otherwise noted. Please note, Pinedale CASTNet data are not included in the design values because this station was not operated in accordance with Part 58 QA requirements until 2007. The design value is the three-year average of the annual fourth highest daily maximum 8-hour ozone concentration (a calculated value less than or equal to 0.075 ppm indicates attainment of the standard; a calculated value of greater than 0.075 ppm is a violation of the standard). Table S.1-2 shows monitored data from other Federal Reference Method (FRM) or Federal Equivalent Method (FEM) ozone monitors in the counties surrounding the UGRB. These monitors have been running for less than 3 years and therefore do not have a design value calculated.

Table S.1-1: Design Values for Monitors In or Near the Upper Green River Basin

Site Name	AQS ID	Year				3-Year Average 2005-2007 (ppm)	3-Year Average 2006-2008[1] (ppm)
		2005 (ppm)	2006 (ppm)	2007 (ppm)	2008 Q1 – Q3 (ppm)		
Daniel South	56-035-0100	0.067[2]	0.075	0.067	0.074	N/A	0.072[1]
Boulder	56-035-0099	0.080[3]	0.073	0.067	0.101	0.073[3]	0.080[1]
Jonah	56-035-0098	0.076	0.070	0.069	0.082	0.072	0.074[1]
Yellowstone (NPS)	56-039-1011	0.060	0.069	0.064	0.065	0.064	0.066

[1] Data collected and validated through 3rd quarter 2008
[2] Incomplete year; began operation in July 2005
[3] Incomplete year; began operation in February 2005

Table S.1-2: 4th Maximum 8-Hour Ozone Values for Monitoring in Surrounding Counties					
Site Name	AQS ID	Year			
		2005 (ppm)	2006 (ppm)	2007 (ppm)	2008 Q1 – Q3 (ppm)
Murphy Ridge	56-041-0101	---	---	0.070	0.061[1]
South Pass	56-013-0099	---	---	0.071[2]	0.065[1]
OCI[3]	56-037-0898	---	0.071[3]	0.066	0.072[1]
Wamsutter	56-005-0123	---	0.067[4]	0.064	0.064[1]
Atlantic Rim	56-007-0099	---	---	0.047[5]	0.064[1]

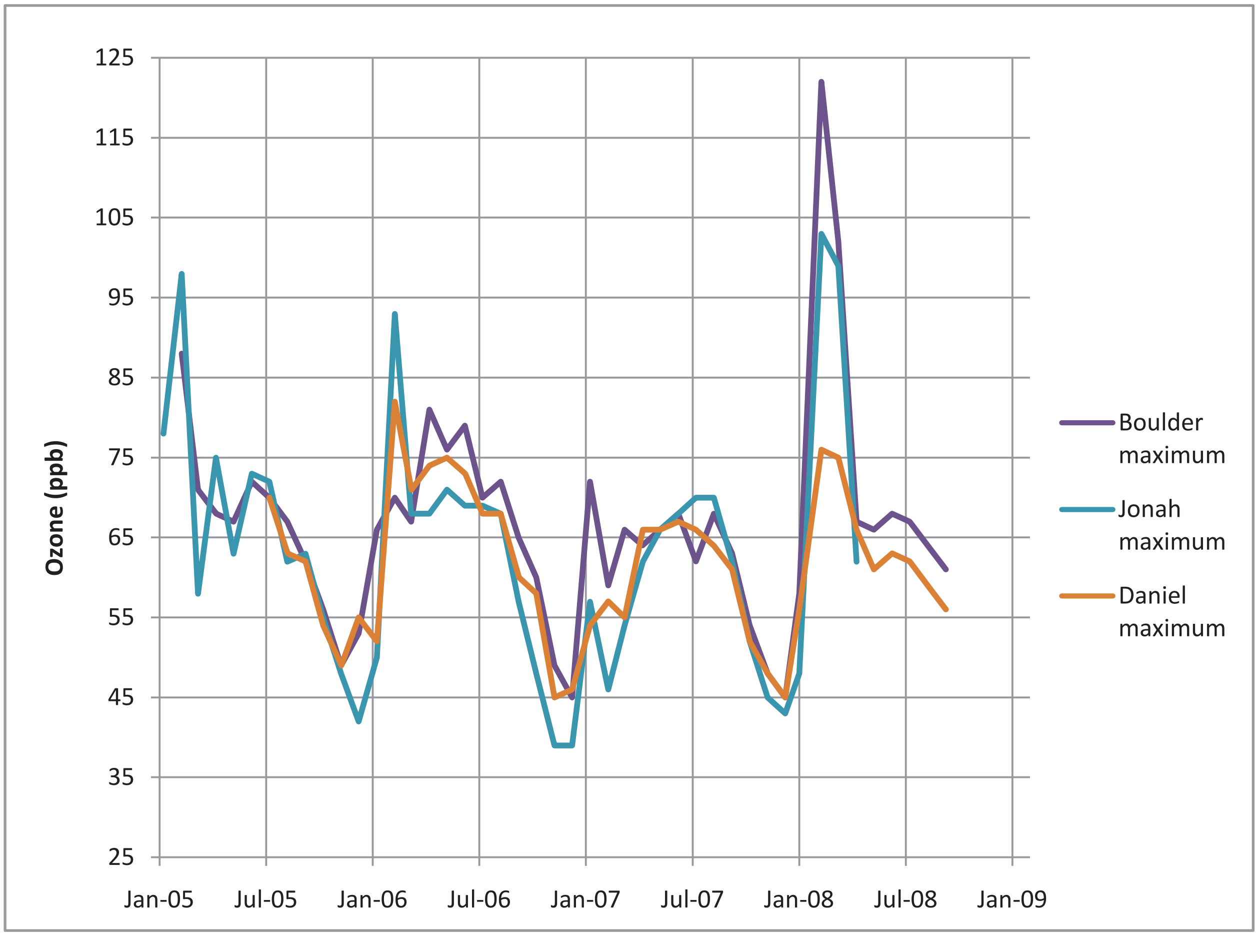
1 Data collected and validated through 3rd quarter 2008
2 Incomplete year; began operation in March 2007
3 Site operated by industry. Incomplete year; began operation in May 2006
4 Incomplete year; began operation in March 2006
5 Incomplete year; began operation in October 2007

Using only data from 2005 through 2007, the monitors for which a design value can be calculated indicate compliance with the ozone NAAQS. Year-to-date data from 2008, however, bring the 2006 - 2008 design value for the Boulder monitor to 0.080 ppm (compared to the standard of 0.075).

While monitors in counties adjacent to the UGRB have not been in operation for a full three-year period (with the exception of the Yellowstone NPS monitor), none of them have 4th-high maximum 8-hour ozone values above 0.075 ppm for any year. This would indicate that, based on ambient monitoring data, ozone levels have not been measured that exceed the standard outside of the UGRB (within Wyoming).

When the data from the Boulder monitoring station, the only monitor showing ozone levels in excess of the standard, is reviewed closely, it shows that elevated ozone typically occurs in the winter. This trend is also evident at the two stations nearby (South Daniel and Jonah). Figure S.1-2 shows the daily 8-hour maximum for these stations on a monthly basis over the last four years. This is an unprecedented phenomenon, as ozone was thought to be a summertime problem. The Wyoming DEQ, with the help of industry, has dedicated significant resources to better understand this situation. The studies indicate that elevated ozone occurs in the UGRB under very specific meteorological conditions, described in greater detail in Section 7 of this document. Briefly, these conditions are the presence of a strong temperature inversion in conjunction with low wind speeds, snow cover and clear skies. These conditions have occurred in January, February, and March.

Figure S.1-2: Monthly 8-Hour Maximum Ozone Within the UGRB



AQD performed Winter Ozone Studies in 2007, 2008 and 2009 in the UGRB. The purpose of these studies is to investigate and monitor the mechanisms of ozone formation during the winter months. These data will in turn be used to develop a conceptual model of ozone formation in the UGRB. As the study has progressed, the scope of the study has been refined as AQD has learned about the unique issue of winter ozone formation. In general terms, the scope of the winter ozone studies include:

1. Placing additional FEM and non-FEM (2B ozone analyzers) monitors throughout the UGRB to characterize spatial and temporal distribution of ground-level ozone.
2. Placing additional three-meter meteorological towers (mesonet) throughout the UGRB to characterize local micro-scale meteorology.
3. Placing additional precursor monitoring (e.g., VOC, NOx and CO) in a few sites around the UGRB to characterize precursor concentrations.
4. Flying a plane equipped with continuous ozone and $PM_{2.5}$ around the UGRB to characterize spatial distribution of ozone (above, in, and below the boundary layer).
5. Launching ozone and rawinsondes to characterize vertical meteorology and ozone distribution.

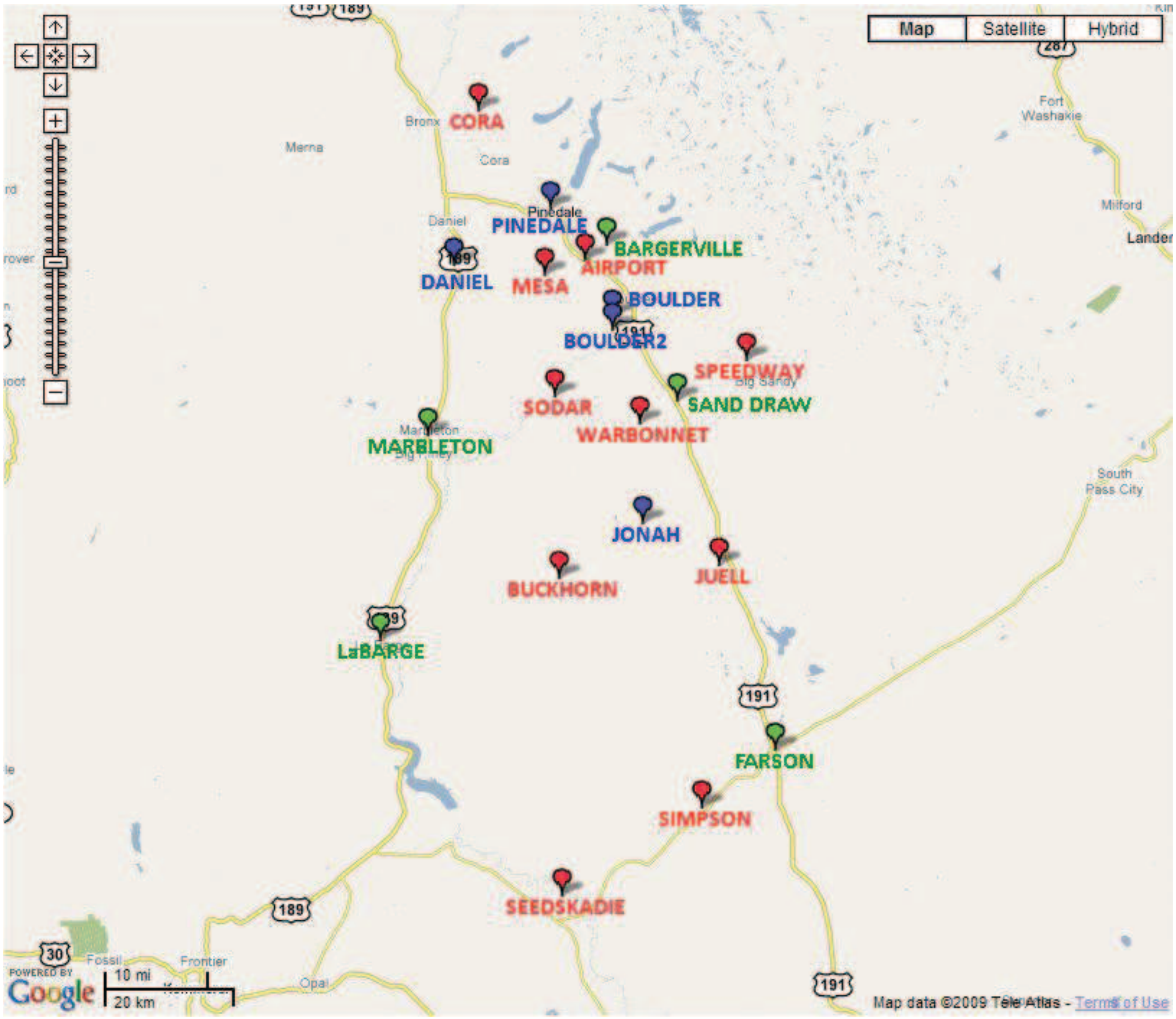
6. Operating ground based upper-air meteorological instruments (e.g., Mini-SODAR, RASS, Wind Profiler) to characterize mixing levels and inversion heights.

In 2007, meteorological conditions did not set up as they had in 2005 and 2006 and elevated ozone did not form in February and March. However, AQD collected data that helped to draw some conclusions about winter ozone formation. The speciated VOC samples collected had a strong oil and gas signature. AQD was able to investigate which detected VOC species were having a greater effect on ozone formation. UV radiation measurements showed that when fresh snow is available, greater than 80% of the ultra-violet light can be reflected.

During the 2008 winter study, several multi-day episodes of elevated ozone were studied. Six additional ozone monitoring locations were added and the plane was flown to provide more information on the spatial and temporal variability around the UGRB. AQD continued to collect speciated VOC samples which confirmed the strong oil and gas signature. These data also allowed us to identify species of interest with respect to elevated ozone formation. AQD also used a mini-SODAR and rawinsondes to characterize the mixing heights and inversion strength on elevated ozone days. It was found that on days with elevated ozone, mixing heights could be as shallow as 50-200 meters above ground level.

For the 2009 winter study, AQD has placed eleven FEM and non-FEM continuous ozone monitors around the UGRB. Additionally, AQD has placed five FEM ozone monitors in communities around the UGRB as part of an Air Toxics study. These monitors compliment the three long-term FEM ozone monitors currently operating. AQD has also added precursor monitoring at the Boulder, Jonah and SODAR stations. Figure S.1-3 shows the current configuration of ozone monitoring in the UGRB.

Figure S.1-3: Winter 2009 Ozone Monitoring in the Upper Green River Basin



While ozone data from these studies cannot be used directly for designation, AQD has used these data to support our recommendation on a nonattainment area boundary for the UGRB. Specifically, VOC data are referenced in Section 2 and mesonet data are used to develop a localized wind field referenced in Section 7. Final reports, quality assurance project plans, and databases from the 2007 and 2008 studies are available on the WDEQ/AQD website: (http://deq.state.wy.us/aqd/Monitoring%20Data.asp). Data from the 2009 study will be posted to the AQD Monitoring page after it has been fully quality assured.

SECTION 2
EMISSIONS DATA

SYNOPSIS

The primary sources of ozone-forming precursors in the recommended nonattainment area are associated with the oil and gas development and production industry in the UGRB.

ANALYSIS

Ground-level ozone is primarily formed from reactions of volatile organic compounds (VOCs) and oxides of nitrogen (NOx) in the presence of sunlight. VOCs and NOx are considered “ozone precursors.” As part of the nine-factor analysis, the Air Quality Division compiled emission estimates for VOCs and NOx for ten source categories in the proposed nonattainment area as well as counties or portions of counties surrounding the area. This information is summarized in Table S.2-1 and represents preliminary estimated first quarter 2007 emission inventory data for all potential sources. Emissions information for 2007 is used because it is the most recently available data for all source sectors. Only the first quarter is shown because elevated ozone in the UGRB occurs during limited episodes in the first three months of the calendar year. In general, quarterly emissions for the second through fourth quarters of the year are the same as for the first quarter, with the exception that biogenic VOC emissions are expected to be greater in the spring and summer months.

When comparing the raw precursor emission totals in Table S.2-1, AQD is aware that the total for the area defined as “Sweetwater Outside of Upper Green River Basin” is the largest for both VOCs and NOx. However, after carefully reviewing the other eight factors to determine an appropriate boundary, AQD has concluded that there are no violations occurring in Sweetwater County, nor are the emissions sources in most of Sweetwater County contributing meaningfully to the observed violations in Sublette County. AQD will demonstrate in this document that the emissions identified in the UGRB, along with other key factors such as site-specific air quality data (Section 1), unique meteorological and geographical conditions (Sections 6 and 7), as well as extraordinary industrial growth rates (Section 5), will explain the exceedances of the ozone standard at the Boulder monitor in Sublette County.

AQD has taken the next step to focus in on the particular emission sources believed to be contributing to high ozone levels. Figure S.2-1 shows emission inventory data for the UGRB. These emission estimates indicate that the most significant sources of ozone precursors in the UGRB are biogenics and the oil and gas industry.

<u>Biogenics</u>

During the first quarter of the year, biogenic emissions are lower than emissions from the other months of the year. The 2007 and 2008 Upper Green Winter Ozone Study (described in Section 1) analyzed canister samples for four biogenic species: isoprene, a-pinene, b-pinene, and d-limonene. Of particular interest is that isoprene, which is a common and highly reactive species of overwhelmingly biogenic origin, was not detected in any of the samples collected at the Jonah monitor and found only at levels just above the method detection limit in one sample at the Daniel monitor and two samples at the Boulder monitor. A-pinene, b-pinene and a-limonene were detected in 3% or less of the samples at each site. These results are consistent with the expected absence of biogenic VOCs in the study area during the winter months.

Biogenic emissions may be overestimated in the standard models used to prepare Table S.2-1, as typical biogenic species have not been detected in significant quantities in canister samples. Alternatively, they may be attributed to forested areas on the east and west flanks of the recommended nonattainment area, which may not influence air composition at Boulder, Daniel, and Jonah during the episodic ozone conditions when canister samples have been taken.

Oil and Gas Production and Development

Oil and gas production and development is the only significant industry emission source within the UGRB. We have divided the emissions from this industry further into those associated with construction, drilling, and completion of wells; well site production; and major sources. Oil and gas production is the largest source of VOCs, with the second largest being biogenic sources. The largest NOx emission sources are from rigs drilling the natural gas wells, natural gas compressor stations (O&G Major Sources) and gas-fired production equipment.

Figure S.2-2 shows the nonattainment boundary and the location of emission sources within and around the boundary. There are 11 major sources within the proposed boundary. Ten of these are compressor stations and one is a liquids gathering system. The figure also shows the distribution of oil and gas wells in the nonattainment and surrounding area.

The boundary encompasses areas of oil and gas development and their respective emissions sources, defined by topography (Section 6) and meteorology (Section 7), which are the most likely sources of ozone-forming precursors influencing the Boulder monitor during elevated ozone episodes.

While the Air Quality Division has been studying the emissions from oil and gas production and development for a number of years, it is an extremely complex industry to understand from an air quality perspective. AQD has made a concerted effort to estimate the emissions impacting the monitors during very unusual circumstances. These efforts will continue and AQD has plans to refine these estimates over time.

Table S.2-1: 1st Quarter, 2007 Estimated Emissions Summary (tons)

	Upper Green River Basin		Lincoln Outside of Upper Green River Basin		Sweetwater Outside of Upper Green River Basin		Uinta		Fremont		Teton	
Emissions Sources	NOx	VOCs	NOx	VOCs	NOx	VOCs	NOx	VOCs	NOx	VOCs	NOx	VOCs
On-Road Mobile Emissions	136	79	155	89	1,727	308	655	122	242	138	157	90
Non-Road Mobile Emissions	36	473	593	208	2,000	174	604	157	101	104	34	256
O&G Well Construction, Drilling & Completion	915	166	243	227	747	870	12	13	102	254	0	0
O&G Production Emissions	327	20,550	148	7,074	460	21,232	133	4,095	281	10,005	0	0
O&G Major Sources	481	198	488	63	9,631	2,200	174	196	111	20	0	0
EGUs Major Sources	0	0	3,151	24	6,335	75	0	0	0	0	0	0
Other Major Sources	0	0	0	0	2,445	1,929	0	0	0	0	0	0
Non-O&G Minor Sources	17	86	346	31	171	56	22	60	10	33	3	0
Biogenic Emissions	0	2,957	0	2,376	0	2,184	0	816	0	5,354	0	3,268
Fire Emissions	5	4	0	0	0	0	0	0	317	232	0	0
Total Emissions	**1,917**	**24,514**	**5,124**	**10,092**	**23,516**	**29,027**	**1,600**	**5,458**	**1,163**	**16,142**	**194**	**3,614**

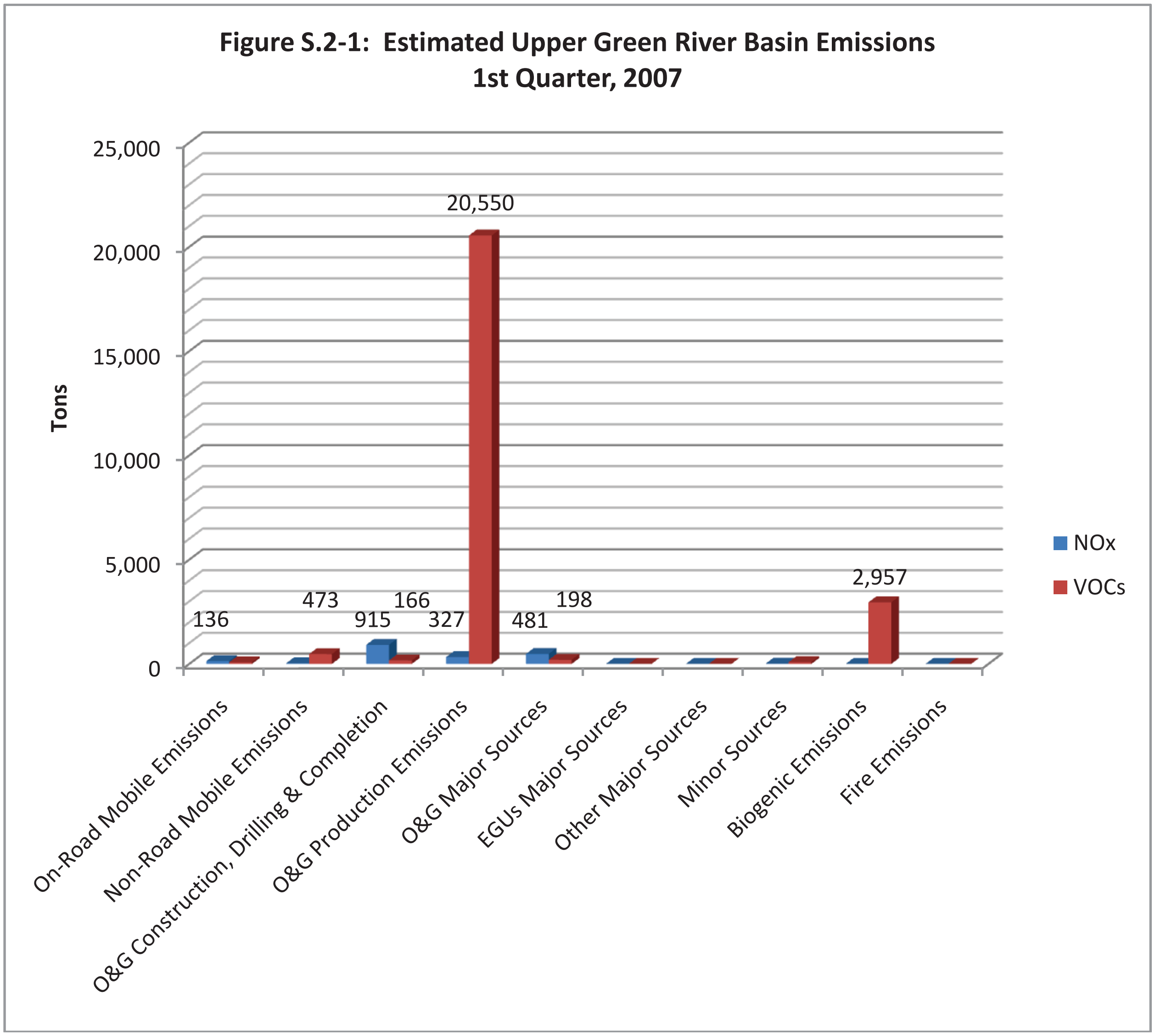


Figure S.2-1: Estimated Upper Green River Basin Emissions
1st Quarter, 2007
25,000
20,000
15,000
10,000
5,000
0
Tons
20,550
136
473
915
166
327
481
198
2,957
NOx
VOCs
On-Road Mobile Emissions
Non-Road Mobile Emissions
O&G Construction, Drilling & Completion
O&G Production Emissions
O&G Major Sources
EGUs Major Sources
Other Major Sources
Minor Sources
Biogenic Emissions
Fire Emissions

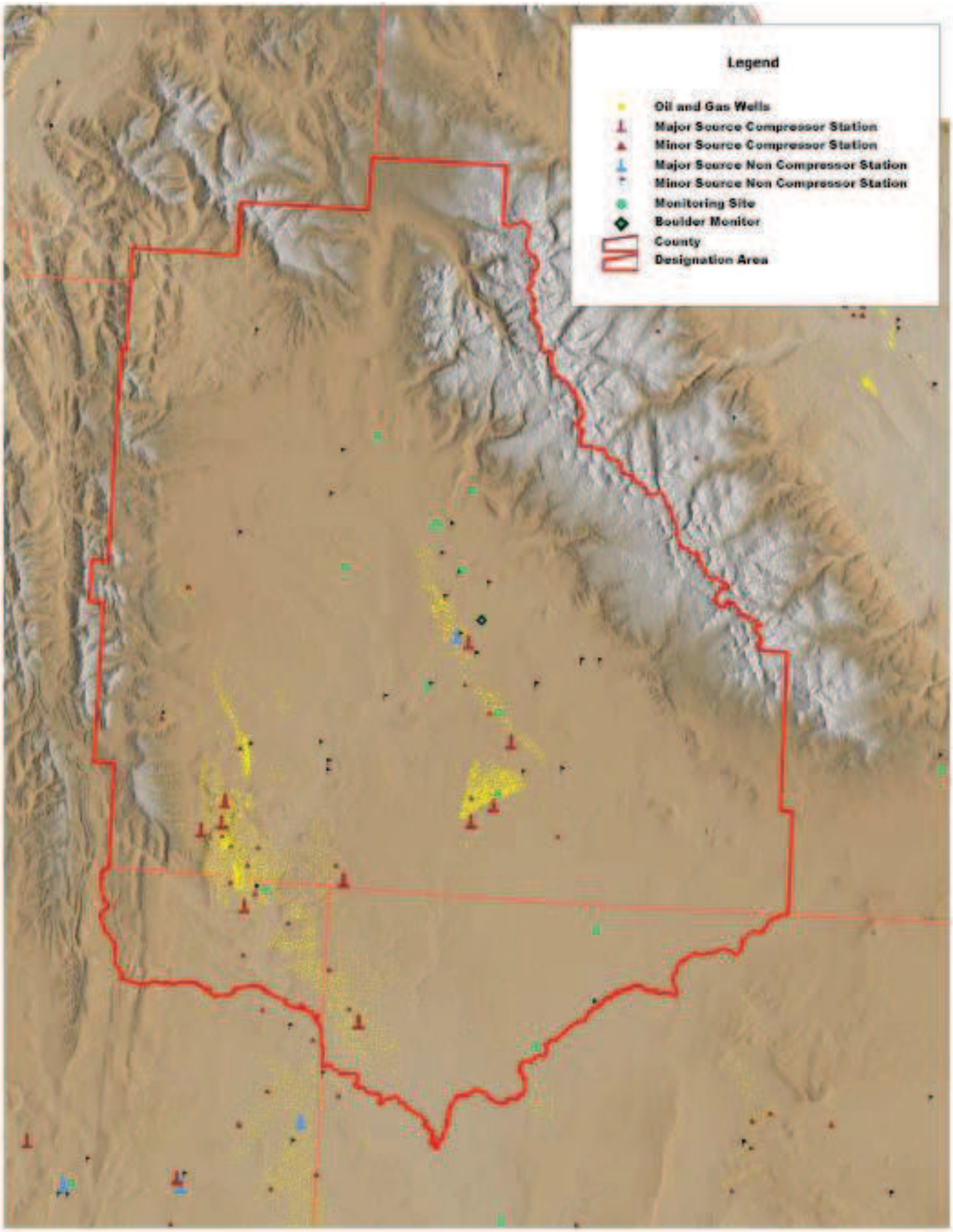


Figure 2.2-2: Designation Area Boundary

SECTION 3
POPULATION DENSITY AND DEGREE OF URBANIZATION

SYNOPSIS

Urbanized areas in surrounding counties do not affect ozone formation or precursors in the proposed nonattainment area just prior to and during elevated ozone episodes, because the urbanized areas are distant and in some cases separated by geographical features such as mountains.

The past and anticipated future rapid population growth is expected to be limited to the proposed nonattainment area, which would suggest that neighboring counties should not be included in the proposed nonattainment area.

Factors which are associated with ozone formation in urban areas have a lower significance for selecting the boundary for this nonattainment area since Southwest Wyoming is mostly rural with a low population density.

ANALYSIS

Sublette County and the surrounding counties (Table S.3-1) are rural with a low overall population density. There are no metropolitan areas with a population of 50,000 or more in this six-county area.

Table S.3-1: Population Density

	Sublette	Sweetwater	Lincoln	Uinta	Fremont	Teton
Estimated 2007 Population	7,925	39,305	16,171	20,195	37,479	20,002
Area (square mile)	4,882	10,426	4,069	2,082	9,183	4,008
Population/square mile	2	4	4	10	4	5
Percent in Urbanized Area*	0	89	20	59	48	56
Percent in Rural Area*	100	11	80	41	52	44

* Based on 2000 Census

The largest community in Sublette County is Pinedale. The estimated population in 2007 was 2,043. The largest communities in the counties surrounding Sublette are Rock Springs (population 19,659), Green River (population 12,072) and Evanston (population 11,483). Rock Springs, Evanston, Riverton and Jackson are classified by the U.S. Census Bureau as Micropolitan Statistical Areas. Table S.3-2 shows population estimates and projections from the Wyoming State Department of Administration and Information.

Table S.3-2: Population Estimates and Projections

County and Cities	2007 Estimate	2008 Forecast	2010 Forecast	2015 Forecast	2020 Forecast	2025 Forecast	2030 Forecast
Sublette	**7,925**	**8,340**	**9,170**	**11,200**	**13,370**	**15,010**	**16,930**
Big Piney	476	501	551	673	803	902	1,017
Marbleton	919	967	1,063	1,299	1,550	1,741	1,963
Pinedale	2,043	2,150	2,364	2,887	3,447	3,869	4,364
Fremont	**37,479**	**37,870**	**38,390**	**39,320**	**40,110**	**41,130**	**42,370**
Dubois	1,033	1,044	1,058	1,084	1,106	1,134	1,168
Lander	7,131	7,205	7,304	7,481	7,632	7,826	8,062
Riverton	9,833	9,936	10,072	10,316	10,523	10,791	11,116
Lincoln	**16,171**	**16,560**	**17,240**	**18,710**	**20,100**	**21,190**	**22,430**
Afton	1,782	1,825	1,900	2,062	2,215	2,335	2,472
Alpine	764	782	815	884	950	1,001	1,060
Kemmerer	2,427	2,485	2,587	2,808	3,017	3,180	3,366
Star Valley Ranch	1,567	1,605	1,671	1,813	1,948	2,053	2,174
Sweetwater	**39,305**	**40,180**	**41,700**	**44,430**	**46,530**	**47,220**	**48,130**
Green River	12,072	12,341	12,808	13,646	14,291	14,503	14,782
Rock Springs	19,659	20,097	20,857	22,222	23,273	23,618	24,073
Teton	**20,002**	**20,240**	**20,570**	**21,340**	**22,140**	**23,470**	**24,990**
Jackson	9,631	9,746	9,904	10,275	10,660	11,301	12,033
Uinta	**20,195**	**20,420**	**20,730**	**21,210**	**21,550**	**21,950**	**22,440**
Evanston	11,483	11,611	11,787	12,060	12,253	12,481	12,760
Lyman	1,990	2,012	2,043	2,090	2,124	2,163	2,211
Mountain View	1,176	1,189	1,207	1,235	1,255	1,278	1,307

Population in Sublette County and Sublette County communities is expected to increase at a rate of approximately 5% over the next 23 years. Population in surrounding counties is expected to increase more slowly at rates of 2% or less.

The population in Sublette County has increased at a greater pace than surrounding counties (Table S.3-3). In the period 2006 to 2007, Sublette County continued to see faster growth than surrounding counties.

Table S.3-3: Population Growth

Population	Sublette	Sweetwater	Lincoln	Uinta	Fremont	Teton
Estimated 2007	7,925	39,305	16,171	20,195	37,479	20,002
Estimated 2006	7,359	38,763	16,383	20,213	37,163	19,288
Estimated 2004	6,879	38,380	15,780	20,056	36,710	18,942
2000	5,920	37,613	14,573	19,742	35,804	18,251
Percent Population Increase						
2000 to 2007	34%	4%	11%	2%	5%	10%
2004 to 2007	15%	2%	2%	1%	2%	6%
2006 to 2007	8%	1%	-1%	0%	1%	4%

Sublette County does not have any urbanized areas. Urbanized areas in surrounding counties are geographically distant from the monitor with the ozone exceedance in Sublette County (the Boulder monitor). As is described in Section 7 of this document, meteorological conditions associated with elevated ozone episodes greatly limit the possibility of emissions transport. Table S.3-4 shows the approximate distance to the Boulder monitor from communities with a population greater than 9,000 in 2007. Additionally, Riverton is separated from the UGRB by the Wind River Range. (Appendix S3 - **Figure -** Wyoming Population Density by Census Tract)

Table S.3-4: Distance to Boulder Monitor
(Miles, approximate)

Riverton	Green River	Rock Springs	Jackson	Evanston
73	82	80	75	118

The analysis in Section 7 of this document will demonstrate that emissions from sources outside of the UGRB do not significantly influence ozone levels at the Boulder monitor during elevated ozone episodes.

References:

1. http://www.census.gov/main/www/cen2000.html, U.S. Census Data.
2. http://eadiv.state.wy.us/pop/CO-07EST.htm, State of Wyoming populations statistics and projections by county and city.
3. Appendix S.3., Population Density by Census Tract

SECTION 4
TRAFFIC AND COMMUTING PATTERNS

SYNOPSIS

The number of commuters into or out of Sublette County (and the UGRB) is small and does not support adding other counties or parts of counties into the nonattainment area based on contribution of emissions from commuters from other counties.

The percent of emissions from on-road mobile sources is small within the proposed nonattainment area: 7% of NOx and 0.3% of VOCs. Even if this source increases, it will remain a small percentage of total emissions.

Interstate 80, the interstate highway that is nearest to the Boulder monitor, is approximately 80 miles south of the Boulder monitor. Ozone monitors in closer vicinity to the interstate have not shown ozone exceedances. I-80 traffic is not considered to be a significant contributor of emissions that impact the Boulder monitor during ozone events.

ANALYSIS

Consistent with the rural character of the counties in southwest Wyoming including Sublette County, traffic volumes are low. The Wyoming Department of Transportation's (WYDOT)[1] inventory shows traffic volume at 447,953 daily vehicle miles traveled (DVMT) for Sublette County in 2007. WYDOT inventories are based on travel on paved roads. Table S.4-1 shows traffic volumes for Sublette County and surrounding counties for 1994, 2004 and 2007.

Emissions from mobile sources within the UGRB are very low, as would be expected from such low DVMTs. As shown in Table S.2-1, NOx emissions for the first quarter of 2007 are approximately 136 tons (7% of total NOx) and VOC emissions are 79 tons (0.3%). This makes emissions from this sector of much lower significance than is typically seen in urban nonattainment areas.

Approximately 90% of the traffic volume in Sweetwater and Uinta Counties is interstate traffic. Interstate 80 is located approximately 80 miles south of the Boulder monitor, the ozone monitor that showed the exceedance. There are five ozone monitors located closer to the Interstate: Wamsutter (~1 mile), OCI (~12 miles), South Pass (~45 miles), Murphy Ridge (~5 miles), and Jonah (~60 miles) (See Figure S.1-1). None of the monitors located closer to the Interstate have shown an ozone exceedance.

Table S.4-1: WYDOT - 2007 Traffic Surveys

	Sublette	Sweetwater	Lincoln	Uinta	Fremont	Teton
DVMT-2007	447,953	2,667,117	615,113	1,013,595	979,546	622,356
DVMT - interstate-2007		2,421,684		911,916		
DVMT-2004	342,034	2,473,882	564,771	944,416	892,814	600,836
DVMT-1994	229,553	1,917,738	466,753	761,626	737,863	504,904
Increase 1994 to 2007	95%	39%	32%	33%	33%	23%
Miles of roads	229.2	568.7	337.2	218.4	507.2	144.2
DVMT/mile of road	1954	4689	1824	4641	1931	4315

The Wyoming Department of Employment (DOE)[2] surveys commuting trends between counties. Table S.4-2 summarizes the average number of commuters for the years 2000 through 2005 that commute between Sublette County (the county with the Boulder monitor) and surrounding counties. Although commuting has increased for some neighboring counties, such as Sweetwater County, the volume of commuters is low.

Table S.4-2: Wyoming DOE Commuter Surveys 2000 Through 2005

Commuters driving to Sublette from:	2000	2001	2002	2003	2004	2005
Fremont	20	29	17	26	41	47
Lincoln	112	117	106	84	100	128
Sweetwater	62	86	79	77	111	185
Teton	49	52	45	35	38	49
Uinta	14	12	22	31	38	53
Total						462
Commuters driving from Sublette to:						
Fremont	81	67	70	37	48	44
Lincoln	77	59	76	114	97	93
Sweetwater	126	129	109	121	152	209
Teton	171	148	150	135	142	130
Uinta	33	66	55	31	20	26
Total						502

North Carolina's Economic Development Intelligence System (EDIS)[3] compiled 2000 Census data to determine the number of commuters in Wyoming counties. Extrapolating this data to 2008, to account for only population growth, the estimated number of commuters in Sublette County and surrounding counties is shown in Table S.4-3. Since rapid population growth in Sublette County is biased toward the working age population, the straight extrapolation from 2000 data is likely to underestimate the number of commuters. The EDIS data indicate the majority of commuters commute within their county of residence. The number of commuters leaving Sublette County calculated by the Wyoming DOE correlates well with the EDIS generated estimates of commuters leaving Sublette County.

Table S.4-3: Number of Commuters in Sublette and Surrounding Counties

	Sublette	Sweetwater	Lincoln	Uinta	Fremont	Teton
Estimated number of commuters in 2000*	2767	18,012	6069	8921	15,074	10,527
Estimated number of commuters in 2008	3357	18,726	7084	9114	15,761	11,811
Estimated number of 2008 commuters that stay in their county	2921	17,977	5596	7565	14,973	11,338

* 2000 Census data

Commuting patterns in Sublette County and in surrounding counties show that commuting to or from the adjacent counties is not a major source of VMT in Sublette County. Therefore, commuters from adjacent counties are not a significant factor in ozone generation in the proposed nonattainment area.

Reference:

1. Appendix S.4.A, 2007 Vehicle Miles on State Highways By County
2. Appendix S.4.B, Commuting Patterns in Sublette County
3. North Carolina Department of Commerce web site. https://edis.commerce.state.nc.us/docs/countyProfile/WY/

SECTION 5
GROWTH RATES AND PATTERNS

SYNOPSIS

The pace of growth in the oil and gas industry in Sublette County is significantly greater than in surrounding counties. While population is growing in Sublette County, the county and surrounding area is rural with a low population density. Population growth does not influence determination of a designation area boundary in this case.

ANALYSIS

Statistical data available is broken down on a county basis. The following analysis compares Sublette County to surrounding counties. While the recommended nonattainment area includes a portion of Sweetwater and Lincoln counties in addition to Sublette, the trends described for Sublette County also hold true, in general, to the recommended nonattainment area.

Population growth is described in Section 3. Sublette County population has grown at an annual rate of approximately five percent over the last seven to ten years. Sublette County is forecast to continue to grow at this rate for the foreseeable future. Counties surrounding Sublette have grown at rates of less than two percent during this time period and are forecast to continue to grow at this slower pace.

Industrial growth in Sublette County is driven by the oil and gas (O&G) industry. Table S.5-1 shows the increase in O&G production for Sublette County as shown by the number of well completions for years 2000 through 2008. Table S.5-2 shows total well completions for 2005 through 2008 for Sublette, Sweetwater, Uinta and Lincoln counties. Sweetwater and Lincoln counties also show an increasing trend in well completions, though to a lesser extent than in Sublette. Teton County is not listed because it has no oil and gas production. Fremont County is not shown because O&G production areas in Fremont County are separated from the other counties by the Wind River Mountain Range.

Table S.5-1: Completion Report Sublette County*

(Confidential Records Are Not Listed)

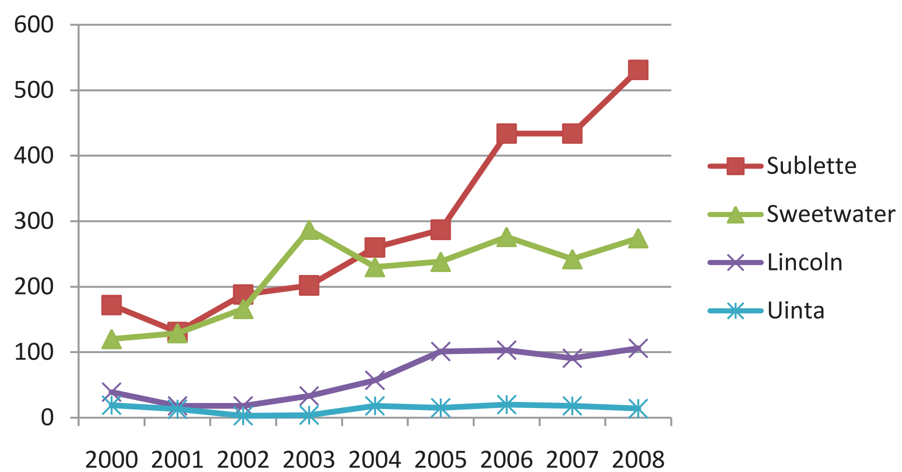
	2000	2001	2002	2003	2004	2005	2006	2007	2008
Distinct Gas Well Completion Count	126	110	150	185	252	281	428	420	517
Distinct Oil Well Completion Count	45	20	32	15	5	0	3	5	4
Total Distinct Well Completion Count	172	131	188	202	260	287	434	434	531

*Wyoming Oil and Gas Conservation Commission (WOGCC)

Table S.5-2: Total Well Completions/Oil, Gas, and CBM* (Confidential Records Are Not Listed)									
	2000	2001	2002	2003	2004	2005	2006	2007	2008
Sublette	172	131	188	202	260	287	434	434	531
Sweetwater	120	129	166	287	230	238	276	242	274
Lincoln	39	18	18	33	57	101	103	91	106
Uinta	19	13	3	4	18	15	20	18	14

*Wyoming Oil and Gas Conservation Commission (WOGCC)

Figure S.5-1: Well Completions Per County



As Figure S.5-1 shows, there have been more O&G well completions in Sublette than for the surrounding counties. Table S.5-3 and Figure S.5-2 show the steady growth in Sublette County O&G production since 2000.

Table: S.5-3 Sublette County Production Levels			
	Oil Bbls	**Gas Mcf**	**Water Bbls**
2008	7,666,396	1,143,614,170	22,921,983
2007	7,096,499	1,008,001,400	18,251,807
2006	5,769,581	880,855,575	13,203,000
2005	5,102,164	814,748,425	11,641,926
2004	4,705,836	731,276,509	11,812,077
2003	4,539,385	655,573,062	10,526,328
2002	4,380,011	571,000,866	13,950,895
2001	3,840,436	493,577,283	7,785,291
2000	3,345,063	448,281,668	7,364,792

Figure S.5-2: Sublette County Gas Production Mcf

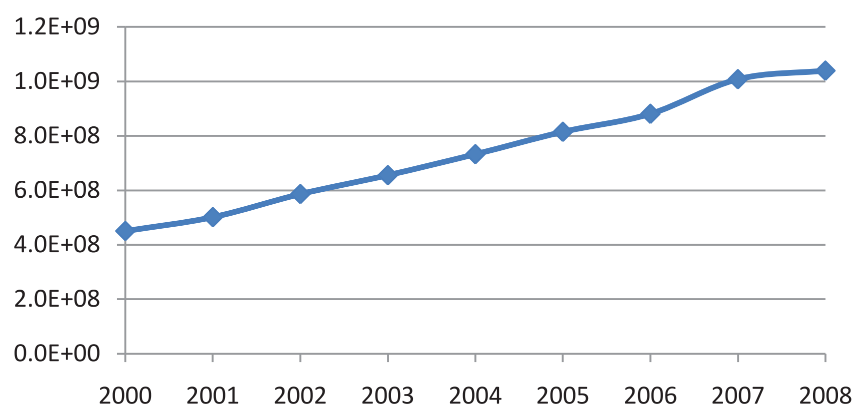


Table S.5-4 shows growth in the oil and gas industry by county through the following three measures: oil production (in barrels), gas production (in thousand cubic feet), and produced water generation (in barrels). Growth in production of gas and water is increasing in Sublette County and is either static or decreasing in the surrounding counties.

Table S.5-4: Four County Production				
	Oil Bbls			
	Sublette	Lincoln	Sweetwater	Uinta
2008	7,666,396	819,751	5,392,316	1,341,993
2007	7,096,499	801,807	5,738,262	1,506,562
2006	5,769,581	782,165	5,295,610	1,914,262
2005	5,102,164	762,801	4,872,531	2,246,896
	Gas Mcf			
2008	1,143,614,170	89,516,900	240,214,449	130,282,928
2007	1,008,001,400	89,189,164	235,687,851	128,068,870
2006	880,855,575	85,753,007	238,339,251	139,700,716
2005	814,748,425	83,579,467	222,772,057	141,490,407
	Water Bbls			
2008	22,921,983	1,228,058	42,026,953	3,011,981
2007	18,251,807	1,300,854	47,522,714	2,843,082
2006	13,203,000	1,375,969	49,928,115	2,641,554
2005	11,641,926	1,065,943	45,110,120	2,950,473

References:

Wyoming Oil and Gas Conservation Commission (http://wogccms.state.wy.us/)

SECTION 6
GEOGRAPHY/TOPOGRAPHY

SYNOPSIS

The Wind River Range, with peaks up to 13,800 feet, bounds the UGRB to the east and north; the Wyoming Range, with peaks up to 11,300 feet, bounds the UGRB to the west.

Significant terrain influences the weather patterns throughout Southwest Wyoming. Other terrain features such as river and stream valleys also influence local wind patterns.

Mountain-valley weather patterns in the UGRB tend to produce limited atmospheric mixing during periods when a high pressure system is in place, setting up conditions for temperature inversions, which are enhanced by the effect of snow cover.

ANALYSIS

Southwest Wyoming and the UGRB are within the Wyoming Basin Physiographic Province. Topography in the UGRB is characterized by low, gently rolling hills interspersed with buttes. Elevations range from approximately 7,000 to 7,400 feet above mean sea level (AMSL) in the lowest portions of the UGRB. The Wind River Range, with peaks up to 13,800 feet, bounds the UGRB to the east and north and the Wyoming Range, with peaks up to 11,300 feet, bounds the UGRB to the west. There are also important low terrain features such as the Green River Basin and the Great Divide Basin.

Mountain elevations decrease moving south along both the Wyoming and Wind River ranges. Along the western boundary of the Green River Basin, in the southern part of the Wyoming Range, the elevation decreases to about 6,900 feet above mean sea level (AMSL) with some peaks in the 7,500 to 8,000-foot range. Moving south along the Wind River Range, the elevation decreases to 7,800 feet at South Pass.

Figure S.6-1: Nonattainment area shown (blue outline) against an aerial view of the topography in the Upper Green River Basin and adjacent areas.

The surrounding significant terrain features effectively create a bowl-like basin in the northern portion of the Green River Basin, which greatly influences localized meteorological and climatological patterns relative to geographical areas located outside of the UGRB. Although difficult to quantify over the entire UGRB valley, the UGRB is roughly 900 to 1,300 meters (3,000 to 4,300 feet) lower than the terrain features bounding the UGRB to the east and west. Typical elevation profiles within the UGRB are illustrated in two different cut-planes (transects) across the UGRB, as shown in Figure S.6-2.

The southern boundary of the area is defined by river and stream channels. To the east the Big Sandy, Little Sandy and Pacific Creek drainages define the boundary and to the west the Green River and Fontenelle Creek drainages define the boundary.

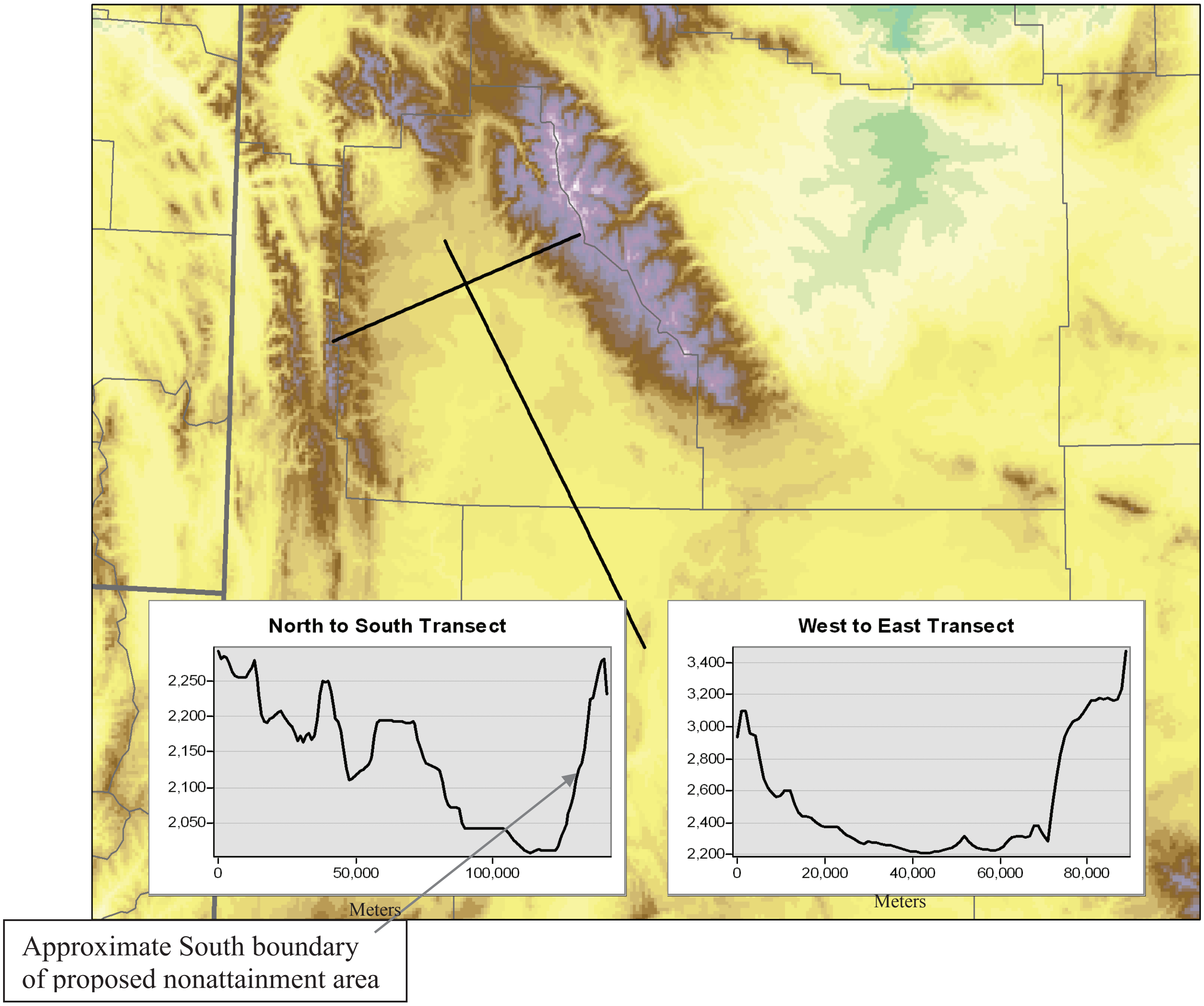


Figure S.6-2: Transects across the Upper Green River Basin (running north-south and west-east) showing cross sections of the terrain; terrain elevations and distance units shown in the transects are in meters.

Significant terrain in the UGRB has an impact on the local meteorology (wind speed, wind direction, and atmospheric stability). In mountain-valley areas – such as the UGRB – during the night cold air will accelerate down the valley sides (downslope winds), while during the day warmer air will flow up the valley sides (upslope winds). At night, this can create a cold pool of air within the UGRB that stratifies the atmosphere (inhibits mixing) since colder, denser air exists at the surface with warmer air above. Further, at the valley floor, the wind speed is likely to be lower than in an open plain as the roughness of the surrounding terrain tends to decrease wind speeds at the surface. The terrain obstacles surrounding the UGRB also tend to cut-off, block, or redirect air that might normally flow through the valley. This effect is exacerbated during times of calm weather, such as the passage of a high pressure system that tends to set up conditions for strong surface-based temperature inversions.

The Wind River Range on the east and the Wyoming Range on the west provide significant barriers to movement of ozone and ozone precursors into the area proposed for a nonattainment area designation. Although the recommended southern boundary is not bordered by a mountain range, the southern boundary lies along two significant drainage divides: the Fontenelle/Green River and the Pacific/Big Sandy River. These geographic features influence air flow, although they do not provide an absolute barrier to migration. The influence of these geographic features on wind flows, especially during periods of low winds which are needed for ozone formation is illustrated in Figure S.7-17. This figure shows winds generally conforming to the drainages which establish the southern boundary of the proposed nonattainment area. The conclusions about the southern boundary are further supported by the meteorological analyses presented in Section 7.

SECTION 7
METEOROLOGY

SYNOPSIS

The unique meteorology in the UGRB of Wyoming creates conditions favorable to wintertime ozone formation.

The meteorology within the UGRB during winter ozone episodes is much different than on non-high ozone days in the winter, and is also much different than the regional meteorology that exists outside of the UGRB during these wintertime high ozone episodes.

The 2008 field study data reveal that, for the days leading up to the February 19-23, 2008 ozone episode, sustained low wind speeds measured throughout the monitoring network were dominated by local terrain and strong surface-based inversions, which significantly limited the opportunity for long-range transport of precursor emissions and ozone to reach the Boulder monitor.

Minimal emissions transport and dispersion, due to the influence of localized winds (light winds) in the UGRB characterize the February 19-23, 2008 ozone episode.

An ozone-event specific wind field was developed to more accurately simulate meteorological conditions in the UGRB and surrounding areas, and was used to drive a trajectory model for air parcel movement into and out of the UGRB.

Trajectory analyses were used to develop a reasonable southern boundary for the nonattainment area.

The unique meteorological conditions in the UGRB are one of the most significant factors for assigning this nonattainment boundary.

ANALYSIS

General

There is significant topographic relief in Wyoming which affects climate and daily temperature variations. This is a semiarid, dry, cold, mid-continental climate regime. The area is typified by dry windy conditions, with limited rainfall and long, cold winters. July and August are generally the hottest months of the year, while December and January are the coldest. Pinedale's mean temperature in January is 12.5°F with a mean of 60°F in July (Western Regional Climate Center, 2009). The high elevation and dry air contribute to a wide variation between daily minimum and maximum temperatures. At Pinedale, the total annual average precipitation is about 10.9 inches, and an average of 61 inches of snow falls during the year.

Strong winds are common in Wyoming, especially in the south. Wind velocity can be attributable, in part, to the prevailing westerly winds being funneled through the Rock Mountains at a low point in the Continental Divide.

The meteorological conditions conducive to the formation of high ozone levels in the UGRB during the winter and early spring are characterized by:

- A stable atmosphere, characterized by light low-level winds

- Clear or mostly sunny skies
- Low mixing heights or capping inversions
- Extensive snow cover
- Low temperatures

The above conditions take some time to develop (at least 48 hours after a storm frontal passage), and occur during periods when the synoptic weather is dominated by high pressure over the western Rockies.

Looking at the meteorological conditions in the UGRB, elevated ozone episodes in 2005, 2006 and 2008 were associated with strong temperature inversions and light low-level winds. This was the case during the February 19-23, 2008 ozone episode, in which the highest ozone concentrations monitored to date in the UGRB were recorded at the Boulder monitor. Because these meteorological conditions are common to all of the high ozone episodes in the UGRB observed to date, the ozone episode of February 19-23, 2008, a 5-day period marking the longest consecutive ozone episode observed, is considered to be representative of other ozone episodes. This particular 5-day ozone episode is the primary focus of this section on meteorological influences and wintertime high ozone.

Winter Ozone Field Studies

After elevated ozone levels were monitored in the winter of 2005 and 2006; the AQD initiated intensive field studies to collect meteorological and ambient data in the first quarter of 2007, 2008, and 2009 throughout the Green River Basin to better understand the relationships between winter meteorological conditions and high ozone levels versus low ozone levels. In spite of careful planning to record data, the winter of 2007 did not produce conditions conducive to the formation of ozone. In contrast, the winter of 2008 provided a significant amount of data on ozone formation since there were several high ozone episodes. A map showing the monitoring sites employed in the 2008 field study and regional terrain features in the 2008 study area is shown in Figure S.7-1. The entire data set and reports on the winter studies completed to date are available on the WDEQ/AQD website (http://deq.state.wy.us/aqd/Monitoring%20Data.asp). AQD has continued field studies into 2009, but those results will not be available until later in 2009.

During January and the beginning of February 2008, the study area was under the influence of a series of weak to moderately strong synoptic disturbances that migrated from the Gulf of Alaska, across the Pacific Northwest and southern British Columbia and the northern Great Basin and into the Northern Rockies. These weather features generally moved rapidly through southwest Wyoming as they migrated along a belt of strong westerly to northwesterly winds aloft that were associated with a persistent high pressure ridge located over the eastern Pacific, off California. In addition, a number of deep Pacific troughs moved across the area earlier in the winter and into the first half of January. The end result of all this activity was the deposit of substantial snow cover in southwestern Wyoming, including the UGRB, which was to remain in place through the rest of the winter. After mid-February, the eastern Pacific ridge exhibited a tendency to extend or migrate into the interior west until it finally moved directly over southwest Wyoming by February 20, 2008.

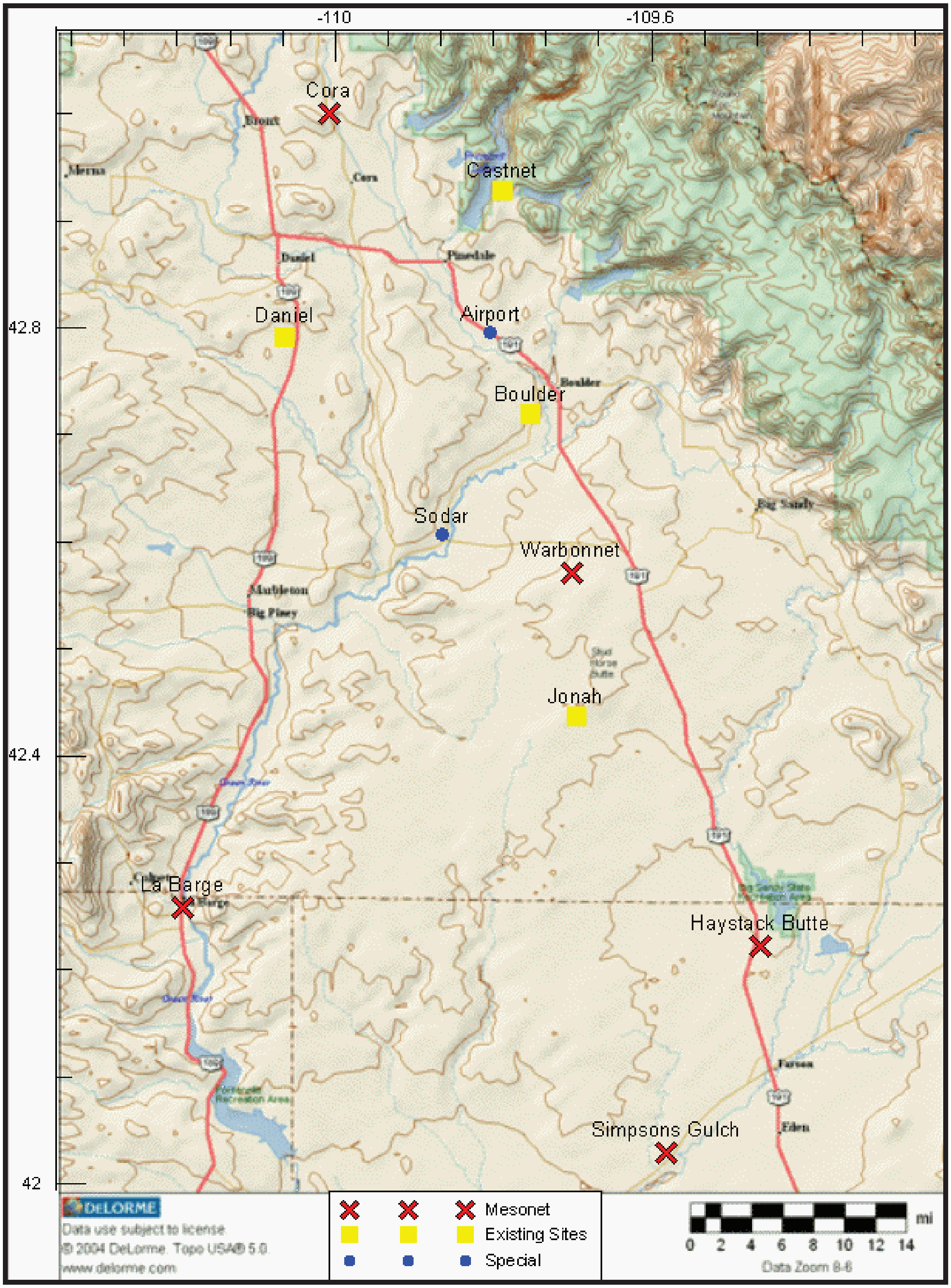


Figure S.7-1. Surface and upper air monitoring sites employed in the 2008 field study.

Comparison of 2007 and 2008 Field Study Observations

Snow Cover and Sunlight

Comparison of meteorological conditions in 2008 with those prevailing during the 2007 field study revealed that one of the key differences was the extensive snow cover in 2008 which was not present during 2007. Snow cover appears to be a key ingredient in winter ozone development, specifically, fresh snow, which results in higher surface albedo, perhaps as great as 0.9. The increased surface albedo results in greater actinic flux and therefore elevated NO_2 photolysis rates. The elevated photolysis rate due to the high (snow cover driven) albedo is likely greater than the photolysis rate in the UGRB in the summer months.

During the 2007 field study, although there were extended periods when synoptic-scale meteorological conditions were conducive to poor horizontal dispersion, the lack of snow cover and subsequent lower UV albedo reduced the amount of UV radiation available for photolysis and associated ozone production. In addition, the 2007 and 2008 field studies suggest that the sensible and radiative heat flux impacts of the snow cover enhance low-level atmospheric stability, substantially reducing vertical mixing during most or all of the daylight hours.

Low Wind Speeds

Stable, stagnant weather conditions occurred in southwest Wyoming during the period from February 18 through 22, 2008. The main synoptic feature responsible for this was a strong Pacific high pressure ridge that slowly migrated across the western United States. This period was dominated by low wind speeds in the boundary layer, which reduced pollutant transport and dispersion. This effect is shown in Figure S.7-2 where ozone concentrations and wind speeds are plotted for the Boulder monitor for February and March of 2008.

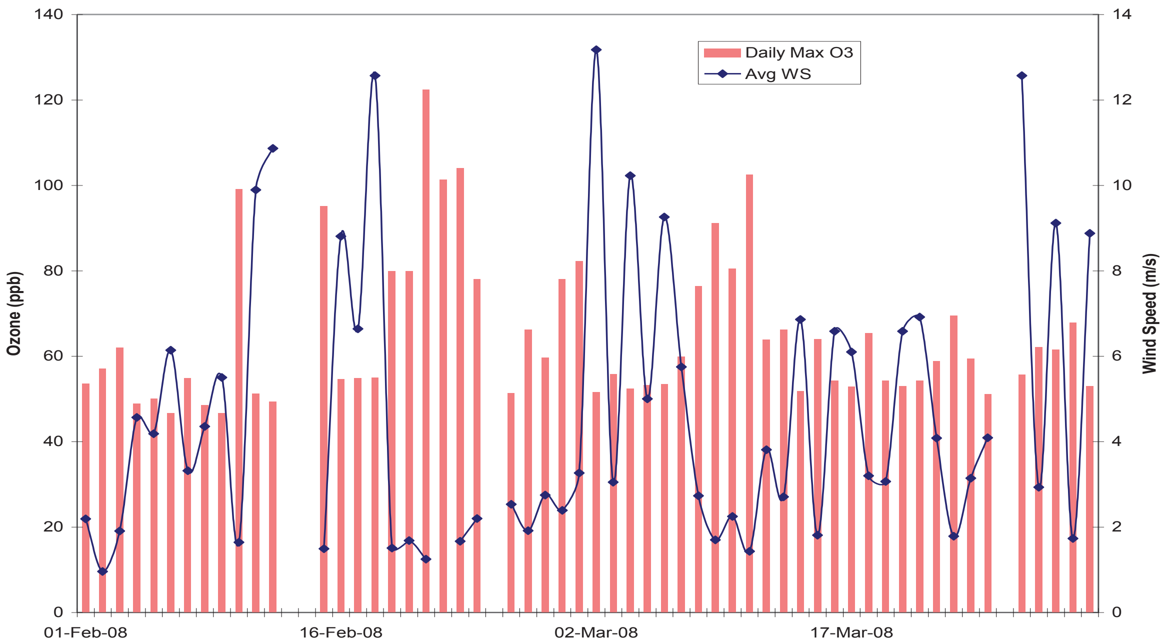


Figure S.7-2. Wind speed and ozone concentrations plotted for the Boulder monitor in February and March 2008.

The 2008 field study data reveal that the sustained low wind speeds measured throughout the monitoring network were dominated by local terrain and strong surface-based inversions, which significantly limited the opportunity for long-range transport of precursor emissions and ozone on the days leading up to the February 19-23, 2008 ozone episode.

Ozone Carryover

When the favorable synoptic conditions described above develop late in the day or during the night hours, the first high ozone concentrations typically develop the following day between approximately 11:00 and 13:00 so long as favorable conditions for high ozone formation persist. During a day of elevated ozone, such as February 20, 2008, the high readings at the monitors in the UGRB peak in the afternoon. As the day progresses, lower but still elevated concentrations continue, in some cases lasting well into the evening hours and, in a few cases, past midnight before lowering. When the following day continues to have these favorable weather conditions, the ozone levels begin to rise earlier than the previous day and frequently to much higher levels, indicative of some carryover of ozone and precursors from one day to the next. Once high ozone concentrations have formed, ozone levels were observed to remain elevated even with increasing cloud cover ahead of an approaching storm system. Additionally, wind reversals, which were most apparent at the Jonah and Boulder monitors, were observed at many of the monitoring sites during the field study; which further assisted in the carryover and build-up of ozone and ozone precursors from emission sources in close proximity to the monitors. Ozone concentrations do not return to near background conditions until brisk (usually west or northwesterly) winds have arrived and scoured out the surface inversion.

Atmospheric Mixing

The observed weather patterns in the 2007 field study showed that the winter storm systems generally did not provide a strong push of cold air and did not produce much precipitation in the project area, but did allow strong wind speeds aloft with considerable mixing of the atmosphere. Specifically, the weather conditions over the study area during February and March of 2007 were characterized by less precipitation (including less snow depth), stronger winds aloft and much warmer surface temperatures compared to the previous two winters. High pressure systems in 2007 tended to keep the air mass over the study area relatively well mixed and mild, which in turn did not allow for snow accumulation and strong inversion development.

Feb. 19 – 23, 2008 Case Study Illustrating the Specific Weather Conditions Which Produce Elevated Ozone in the Upper Green River Basin

This ozone episode is of particular interest for study, as it: 1) occurred over five days, marking the highest 1-hour and 8-hour ozone concentrations recorded at the Boulder monitor to date, 2) occurred during a field study Intensive Operating Period (IOP) that was in place to measure detailed actual ambient and meteorological conditions leading up to and during this multi-day winter ozone episode, 3) provides a high quality database of observations for several meteorological parameters, both during IOPs and regular hourly observations during this ozone episode, and 4) provides information which clearly shows how the topography in the Upper Green River Basin creates different meteorological conditions within the UGRB. A summary of the daily maximum 8-hour averaged ozone concentrations monitored at the Jonah, Boulder, and Daniel FRM monitors during this ozone episode, as well as the day immediately preceding it, are provided in Table S.7-1.

Date	Jonah (ppb)	Boulder (ppb)	Daniel (ppb)
2/18/09	45	55	54
2/19/08	80	79	74
2/20/08	75	79	76
2/21/08	84	122	62
2/22/08	102	101	76
2/23/08	76	104	74

Table S.7-1. Summary of daily maximum 8-hour averaged ozone concentrations monitored at the Jonah, Boulder, and Daniel monitors during February 18-23.

A synopsis of the particular meteorological conditions associated with the February 19-23, 2008 winter high ozone episode is provided below, describing the evolution of the meteorological conditions that were in place during the February 19-23, 2008 ozone episode.

Synopsis of 19 – 23 February 2008 Ozone Episode

Figure S.7-3 shows the 700 millibar (mb) chart for the morning of February 19, 2008, which shows the axis of the Pacific ridge extending north and south from the Four Corners area, through northwestern Idaho and up into eastern British Columbia. At that time, the ridge axis was still west of Wyoming, resulting in fairly strong northwesterly gradient flow (winds blowing from the northwest along the isobars) just above ground level in southwest Wyoming. With clear skies accompanying the approaching ridge, and a good snow cover at the surface, a capping inversion formed overnight and persisted throughout the next day in the UGRB. However, the strong winds above the stable layer, along with mixing heights on the order of several hundred meters, transferred sufficient momentum downward, allowing these northwest winds to mix down to the surface during the day resulting in predominant northwesterly wind patterns within the UGRB.

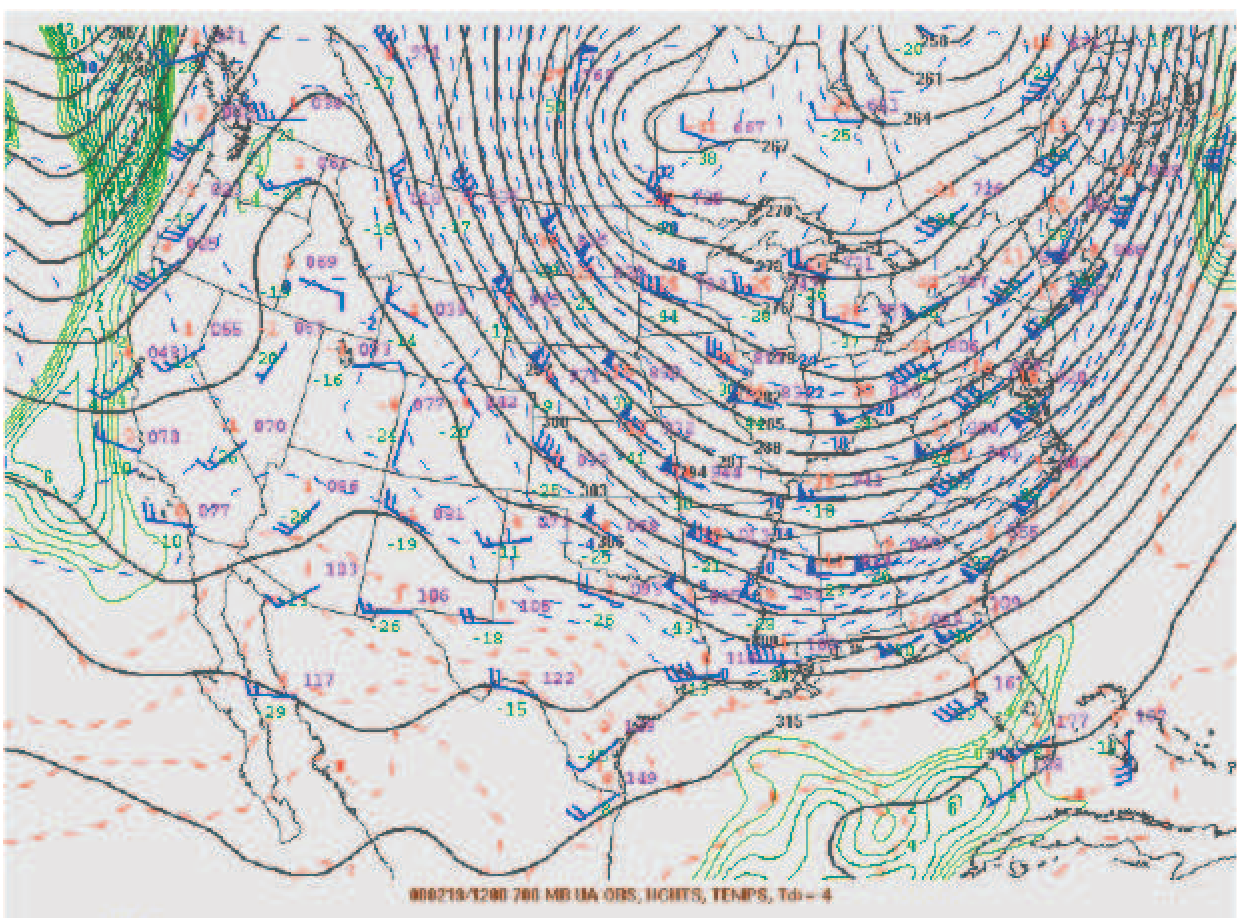


Figure S.7-3. Constant pressure map for 700 mb, 02/19/08 (1200 UTC) [(5 am LST)].

The high pressure ridge continued to progress slowly eastward during February 20th resulting in the central axis pushing into southwestern Wyoming by the middle of the day. As a result, a capping low-level inversion was observed throughout the day, and a weakened northwest gradient wind flow allowed the establishment of local valley flow patterns in the area. Local valley flow patterns are characterized by light variable winds with pronounced down slope winds at night. A weak storm system that moved out of California and across the southern Great Basin during February 20th forced some broken high cloudiness over southwestern Wyoming during the afternoon, but the clouds failed to curtail ozone production in the area, based on monitored data.

Figure S.7-4 shows the 700 mb chart for the evening of February 21, 2008. Although the high pressure ridge had weakened by the afternoon of February 21st, it had also flattened and the central ridge axis was over southwestern Wyoming through the entire day. The resulting light wind situation, characterized by low wind speeds and significantly reduced air flow movement within the UGRB, enabled the strongest ozone production seen to date in Sublette County.

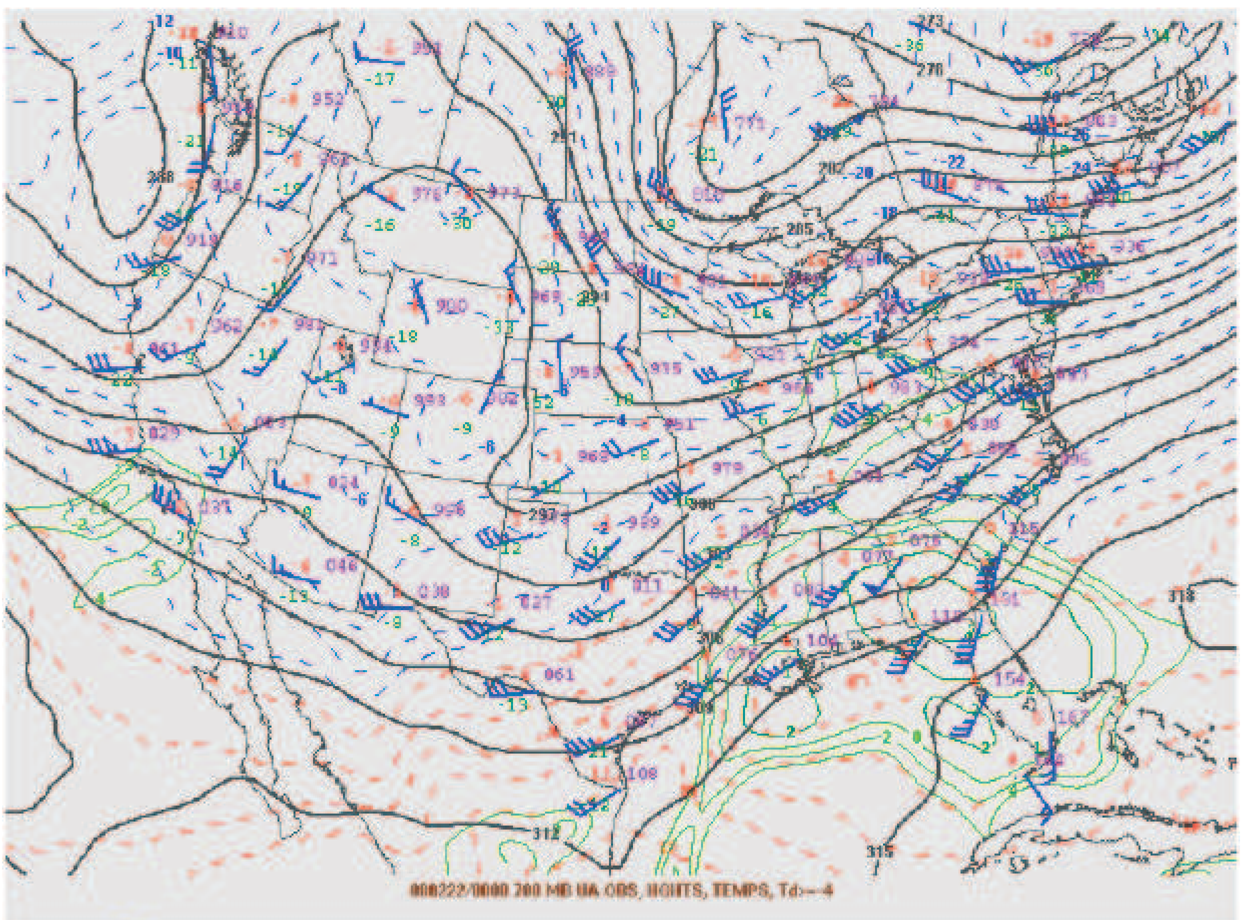


Figure S.7-4. Constant pressure map - 700 mb, 02/22/08 (0000 UTC) [02/21/08 (5 pmLST)].

On February 21, 2008, the low level inversion stayed intact through the entire daylight period, keeping ground level emissions trapped near the surface. With the very light and variable winds above the inversion (see Figure S.7-10) localized wind flow patterns near the ground level developed during the day allowing emissions to transport along those pathways (see Figure S.7-6 and Figure S.7-7). The height of the 700 mb pressure surface during the day was around 3,020 meters (MSL), the temperature averaged about -6° C, and the wind speeds were less than 5 knots. The height of the 500 mb pressure surface averaged around 5,550 meters (MSL) and the wind speeds at that height were around 15 knots.

The high pressure ridge continued to weaken during February 22, 2008, while a shortwave low pressure trough approached southwestern Wyoming from the northwest. Skies became mostly cloudy during the morning hours and light precipitation spread over the area later in the afternoon; the low level inversion stayed intact well into the afternoon, and ozone concentrations remained high during most of the day. It was anticipated that the stable layer would be mixed-out by the trough by early morning the next day and trapped emissions would be dispersed. Instead, the late arrival of the trough allowed one more day of high ozone concentrations.

Description of Surface Wind Data

With the addition of the temporary mesonet monitoring sites to the existing permanent meteorological monitoring stations in the 2007 and 2008 field studies, a fairly detailed picture of wind flow patterns within the UGRB was obtained, revealing that the wind flow patterns were distinctly different throughout the northern and southern portions of southwest Wyoming. A composite map of wind rose plots generated from meteorological data collected throughout southwest Wyoming during the time period 18 – 22, February 2008 is provided in Figure S.7-5.

As can be seen in Figure S.7-5, the wind patterns in the northern portion of Sublette County reflect the prevailing northwest winds typical of this area during most of the year. However, this moderately strong, organized northwest flow does not extend to the southern monitoring sites (Haystack Butte and Simpsons Gulch). Monitoring sites located in Sweetwater, Lincoln and Uinta Counties experienced a generally westerly wind flow, which was also a characteristic of the prevailing flows noted during the 2007 field study at those monitoring sites. Additionally, during the afternoon, winds reversed at some monitoring sites in the UGRB, shifting from the northwest to the southeast; this mid-day flow reversal is typical of high ozone days in the UGRB, and is thought to be causing recirculation of pollutants within the UGRB.

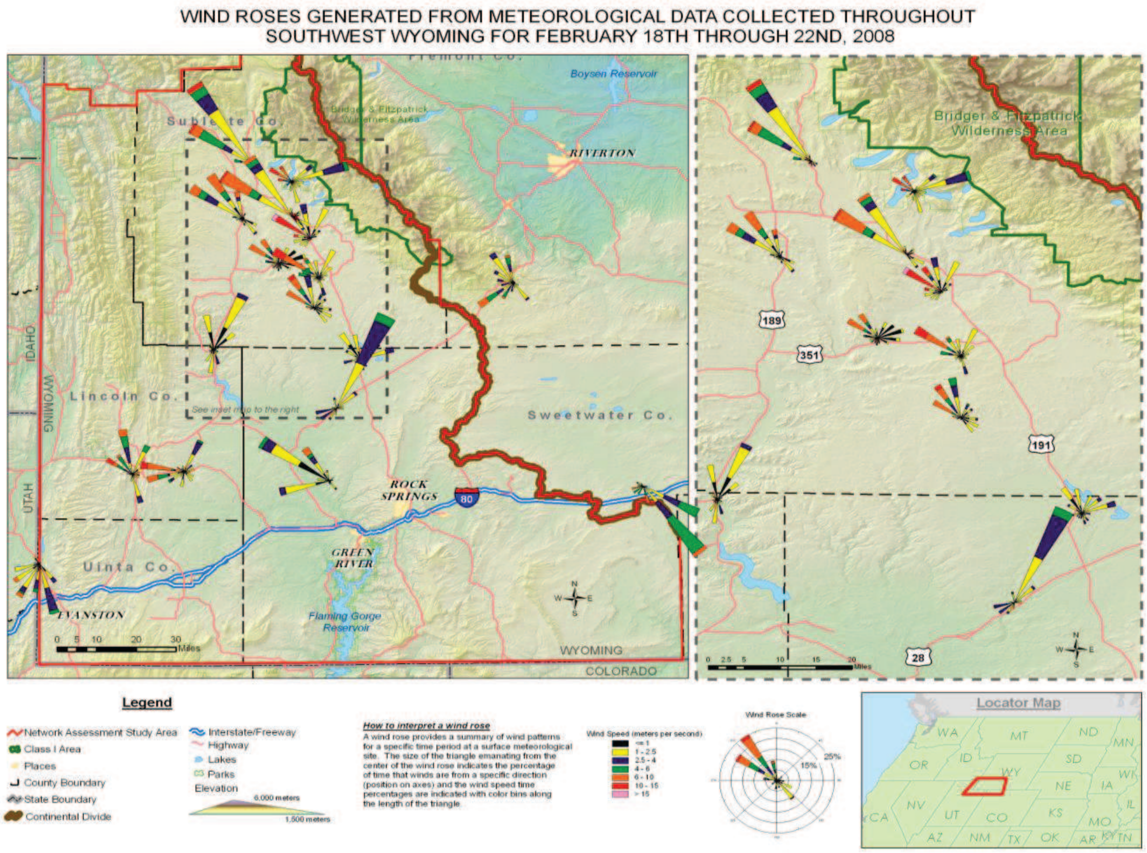


Figure S.7-5. Composite wind rose map for February 18 – 22, 2008 at monitoring sites located throughout Southwest Wyoming.

Wind vector fields were also examined spatially to gain an understanding of flow patterns in the field study area. Winds on a typical ozone episode day (February 20th), and on the day with the highest 8-hour ozone concentration recorded at the Boulder monitoring site (February 21st) are shown in Figure S.7-6 and Figure S.7-7.

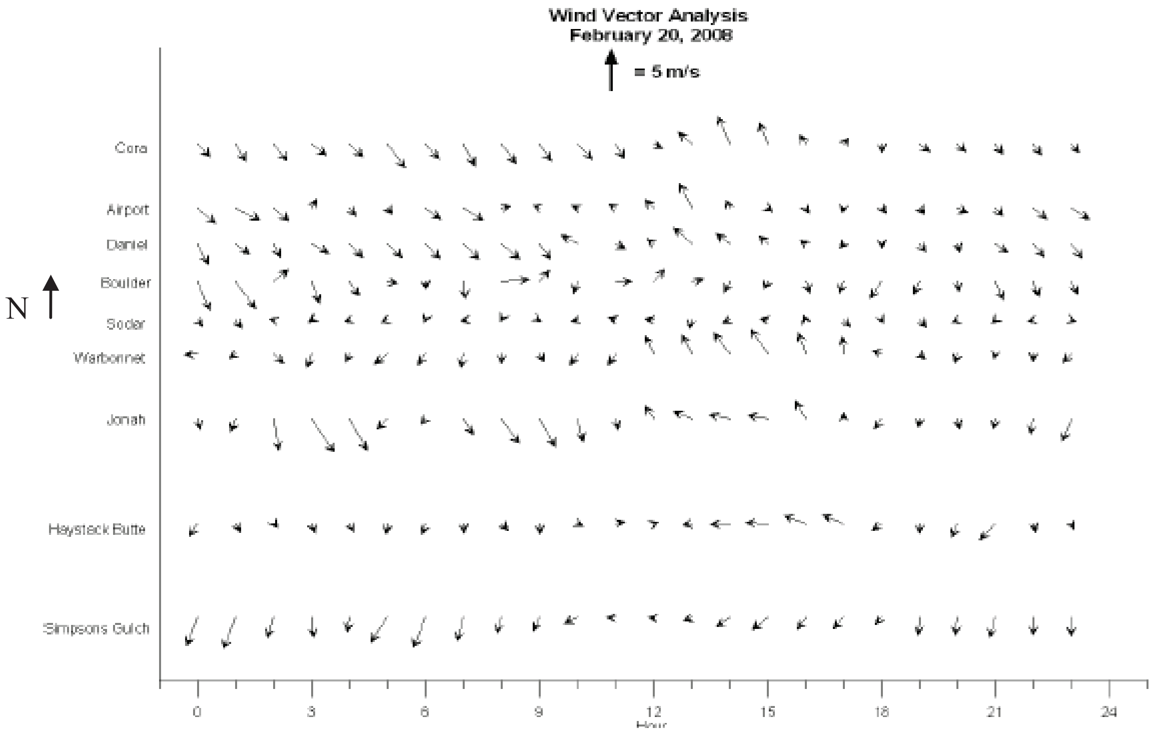


Figure S.7-6. Time-series showing February 20, 2008 hourly wind vectors for monitors used in 2008 field study monitoring network.

As shown in Figure S.7-6, winds in the UGRB are generally out of the northwest in the morning until about mid-day, at which point the flow has reversed with southeasterly winds, or at least southerly component winds are observed at most sites. This continues through the afternoon until 18:00 MST at which time the flow begins to switch back to the northwest, and by 6:00 MST the following morning, winds are northwest or northeast at nearly all of the monitoring sites. The switch from an overnight flow consisting of generally northwesterly or down slope winds, which last until approximately mid-day before reversing to a generally southeasterly wind flow pattern during the afternoon, was repeated on many of the 2008 ozone episode days.

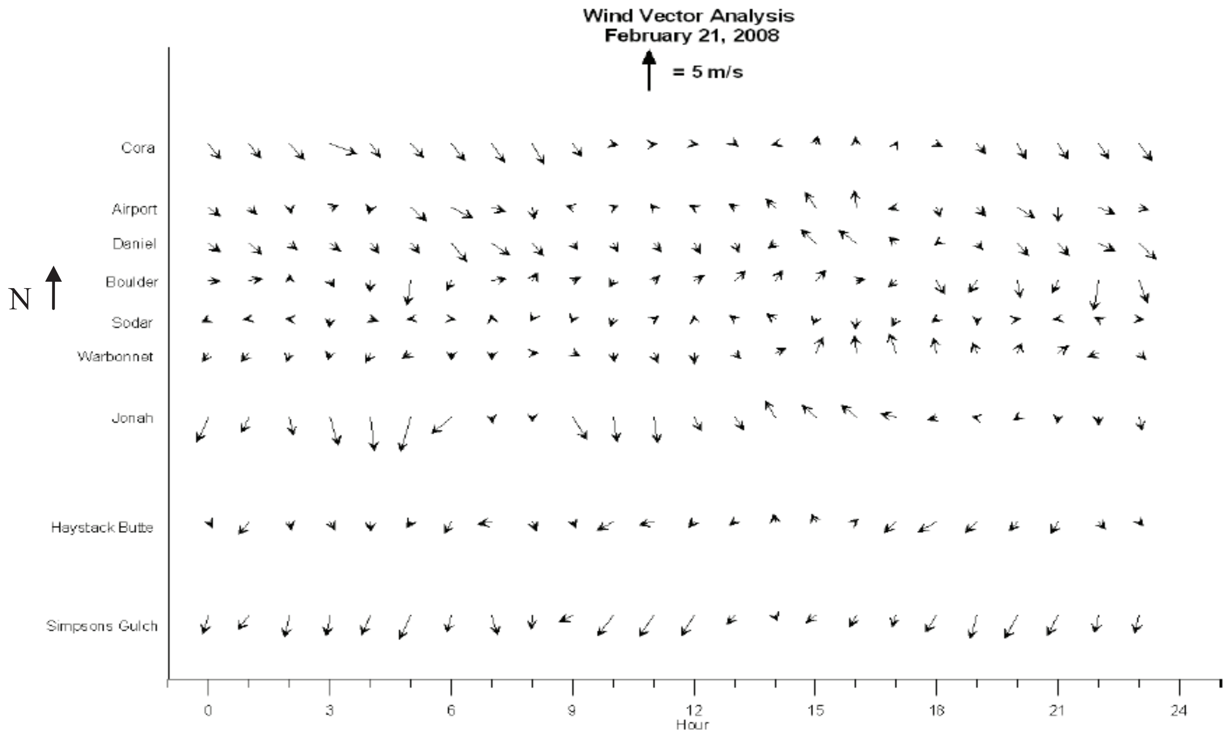


Figure S.7-7. Time-series showing February 21, 2008 hourly wind vectors for monitors used in 2008 field study monitoring network.

As shown in Figure S.7-7, winds on February 20th and 21st were generally light with variable directions throughout the monitoring network. There were two notable exceptions. After midnight, there was a general light northwest flow suggestive of a regional drainage pattern as colder, heavier air from the higher elevations flows downhill.

Generally stronger winds were measured at Jonah in the forenoon hours relative to the other sites in the network; this effect is also sometimes seen at Daniel and is likely due at least in part to the fact that winds at these two sites are measured on a standard 10 meter tower whereas the other sites made use of 3 meter high tripod mounted anemometers. During the afternoon, winds reversed at some sites, shifting to the southeast. This mid-day flow reversal is typical of high ozone days in the UGRB. On February 20, 2008, peak 8-hr ozone concentrations in the 70-85 ppb range were measured at sites throughout the study area; on February 21, 2008, the Boulder monitor recorded a 122 ppb 8-hr average ozone concentration. High ozone continued on February 22, 2008 with the Jonah monitor recording a daily maximum 8-hour average ozone concentration of 102 ppb. Minimal emissions transport and dispersion, due to the light winds in the UGRB, were characteristic throughout the February 19-23, 2008 ozone episode.

The South Daniel FRM monitor which is in the northwest portion of the recommended nonattainment area is typically upwind of local precursor sources and the Boulder monitor. On February 20 ambient nitrogen dioxide (NO_2) concentrations at the Daniel monitor were essentially equal to zero (0) ppb for all 24 hours; very low concentrations of VOCs were also measured in the VOC canister samples collected at Daniel on this day. Nearly identical values were observed at the Daniel monitor and in the Daniel VOC canister samples obtained throughout the ozone episode (February 19-23, 2008); this was also the case during all three IOPs. The canister samples collected at the Daniel monitor in the 2007 field study also showed consistently low VOC concentrations. Additionally, monitored NOx concentrations recorded at Daniel have been very low since this site began operation nearly four years ago; the VOC canister data and the NOx monitoring conducted at Daniel clearly indicate the air coming into this area has low ozone precursor concentrations. Additionally, based on the 2008 field study data at the Daniel monitor, background ozone concentrations during the winter are typically in the 50 - 60 ppb range. Daily maximum 8-hour ozone concentrations at the Daniel monitoring site during the February 19-23, 2008 ozone episode ranged between 62-76 ppb.

One view of the surface wind direction-ozone relationship is shown on Figure S.7-8, which presents a wind rose using measurements from the Boulder monitoring site. This diagram is constructed using the daily peak 8-hr ozone level and 15:00 MST hourly averaged winds. These results show that high ozone levels were associated with afternoon winds from a variety of directions, reflecting the "light and variable" nature of the surface layer winds when the monitored 8-hour ozone levels were above 75 ppb, as opposed to 8-hour ozone concentrations that were less than 75 ppb, which tend to be associated with persistent higher wind speeds and the predominant northwest flow direction along the valley axis.

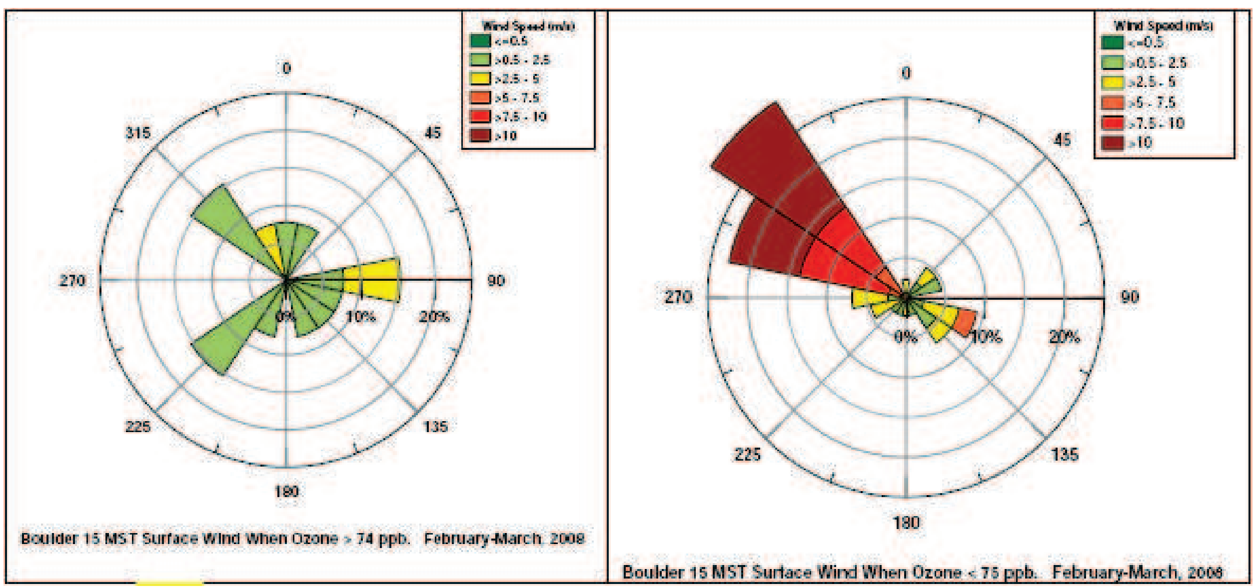


Figure S.7-8. Wind roses based on 15:00 (MST) data from the Boulder site for days with maximum 8-hour average ozone a) greater than 74 ppb (left) and b) less than 75 ppb (right).

Description of Conditions Aloft

A multi-level SODAR was operated continuously at a location approximately 3 miles southwest of the Boulder monitoring site during the 2008 field study. The SODAR provided two types of data: 1) vertical profiles of wind speed and wind direction at 10-meter increments up to 250 meters above ground level, and 2) information which allows an estimation of mixing height (mixed layer depth). The regular hourly observations during the 2008 field study were supplemented with high resolution measurements of vertical wind speed, wind direction, and temperatures during the IOPs. The hourly meteorological data capture rate was excellent. Comparing the measured wind data with peak 8-hour ozone concentrations at Boulder, a strong correlation between ozone concentrations and low mixed layer average wind speeds is evident. Looking at SODAR data on the afternoon of February 21, 2008, a day when 8-hour ozone concentrations above 75 ppb were noted throughout the field study area, reveals a top to the mixing layer at about 100 meters above ground level (AGL) representing a very shallow layer trapping ozone precursors and other pollutants in high concentrations near the surface.

Similar vertical profiles (soundings) and boundary layer development were measured by balloon-borne observations (ozone measurements, temperature, relative humidity and winds) on each of the high ozone days. Stable atmospheric conditions prevailed, and were characterized by strong low-level temperature inversions with very shallow mixing heights and light boundary-layer winds**.** Peak ozone concentrations were often observed somewhat above the surface but still within the stable inversion layer. As shown in Figure S.7-9, at low mixing heights (below 100 meters), the highest values of ozone were observed. Table S.7-2 provides a summary of the days with low-level capping inversions, and the measurements obtained, including the date and time of each balloon launch, the ground temperature and maximum inversion temperature (temperature at top of inversion layer), the difference between the maximum inversion temperature and the ground temperature (inversion layer Delta T), which reflects the strength of the temperature inversion. Note the highest inversion layer temperature measured is 14.5 (^{o}C) and occurs on February 19th.

Launch Date	Launch Time (MST)	Ground Temp (^oC)	Max Inversion Temp (^oC)	Inversion Layer ΔT (^oC)	Inversion Height (meters AGL)
2/18/08	11:00	-3.8	-3.2	0.6	150
2/18/08	16:00	-1.8	-1.7	0.1	47
2/19/08	7:00	-14.8	-0.3	14.5	489
2/19/08	1100	-8.1	1.3	9.4	442
2/19/08	13:00	-5.3	2.2	7.5	403
2/19/08	16:00	-4.5	1.8	6.3	445
2/20/08	7:00	-13.6	-2.4	11.2	398
2/20/08	1100	-13.9	-2.0	11.9	342
2/20/08	13:00	-7.7	-3.2	4.5	449
2/20/08	16:00	-5.4	-2.3	3.1	543
2/21/08	7:00	-17.4	-4.0	13.4	500
2/21/08	1100	-7.9	-3.0	4.9	405
2/21/08	13:00	-3.4	-2.6	0.8	373
2/21/08	16:00	-5.7	-2.9	2.8	494
2/27/08	8:00	-9.7	-1.4	8.3	670
2/27/08	1100	-5.4	0.1	5.5	711
2/27/08	13:00	-2.3	1.0	3.3	608
2/27/08	16:00	-1.2	0.7	1.9	527
2/28/08	8:00	-8.6	-2.3	6.3	149
2/28/08	1100	-1.4	-2.4	-1.0	265
2/28/08	13:00	1.8	0.0	-1.8	91
2/28/08	17:00	0.5	1.0	0.5	190
2/29/08	8:47	-6.2	-2.5	3.7	460
2/29/08	1100	-8.9	-0.3	8.6	396
2/29/08	13:00	-1.4	0.3	1.7	314
2/29/08	16:00	-0.3	1.5	1.8	470
3/10/08	8:00	-12.2	-5.8	6.4	470
3/10/08	1100	-7.6	-5.0	2.6	480
3/10/08	14:00	-1.6	-2.1	-0.5	312
3/10/08	17:00	-1.3	-2.0	-0.7	705
3/11/08	8:00	-13.1	1.3	14.4	373
3/11/08	1100	-2.4	1.5	3.9	312
3/11/08	13:00	2.1	2.0	-0.1	252
3/11/08	17:00	0.5	1.2	0.7	236
3/12/08	8:00	-9.3	-2.1	7.2	142
3/12/08	1100	2.3	2.5	0.2	90
3/12/08	15:00	3.5	-0.3	-3.8	261

Table S.7-2. Summary of low-level temperature measurements, and related data on inversion strength.

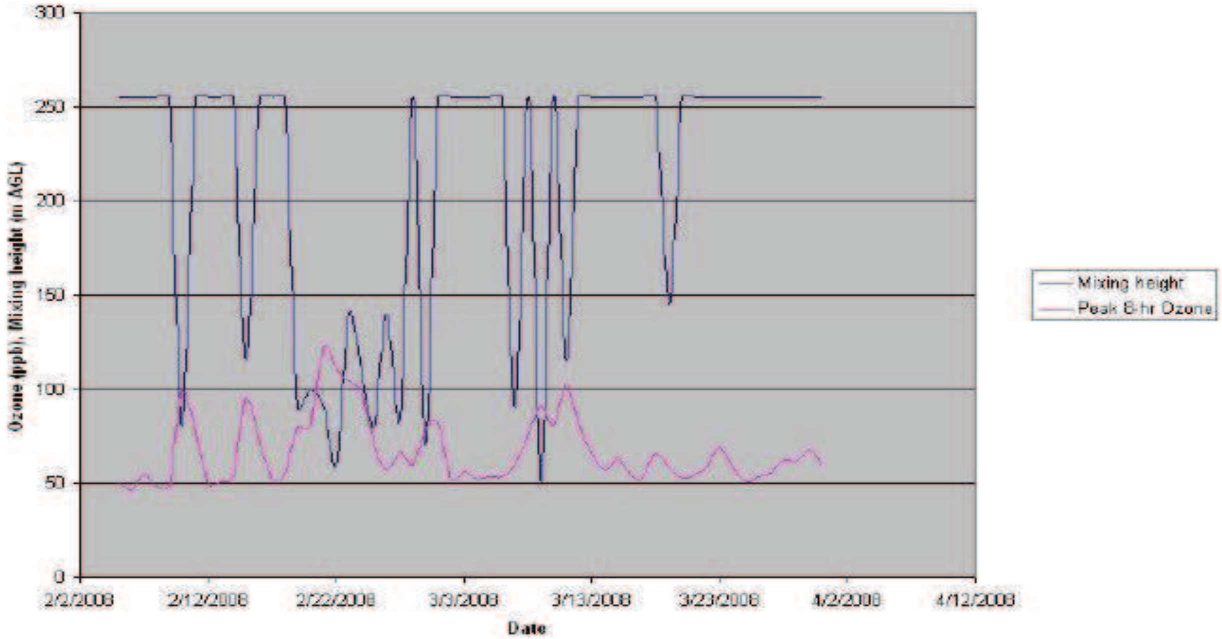


Figure S.7-9. SODAR-reported mixing height versus peak daily 8-hour ozone concentrations at Boulder. Measurements limited to below approximately 250 meters above ground level (AGL).

Soundings taken in the forenoon and afternoon of February 21, 2008 are shown in Figure S.7-10. Profiles for ozone (black line), temperature (red line), dew point temperature (dashed blue line) and winds (vectors) are plotted as functions of height above the ground elevation of the balloon launch site. A strong low-level inversion was present up to 2,500 meters-msl (~ 400 meters-agl) with a maximum temperature at the top of the inversion of -2.9 ^{o}C, several degrees warmer than the temperature at the surface. Boundary-layer winds in the forenoon were light from the west when ozone levels were ~50 ppb, before becoming southeast in the afternoon.

Figure S.7-10 shows the inversion is setting up in the morning of February 21, 2008, and that the inversion persisted through daylight hours, resulting in high ozone concentrations beneath the inversion. Figure S.7-10 also shows that at 11:00 (MST) ozone concentrations were ~ 50 ppb below the inversion height of 2,500 meters (MSL) which is shown by the green circle (left pane) towards the bottom of Figure S.7-10; measured ozone levels above the inversion layer were also generally ~ 50 ppb.

Normally, some vertical mixing of the air would exist, as the temperature aloft begins to fall off with increasing height above ground; however, the strong surface-based inversion persists to 4:00 pm, effectively inhibiting vertical mixing. A shallow layer of high ozone (> 110 ppb) was present in the afternoon (16:00 MST) sounding, which is shown by the green oval (right pane) towards the bottom of Figure S.7-10. Ozone concentrations decrease rapidly with height below the inversion; ozone levels above the inversion are about 50 ppb. Note that the vertical wind shear measured at the top of the inversion layer height above ground (wind arrows on the right side of graphs) attest to the complete decoupling of the boundary layer air from layers aloft.

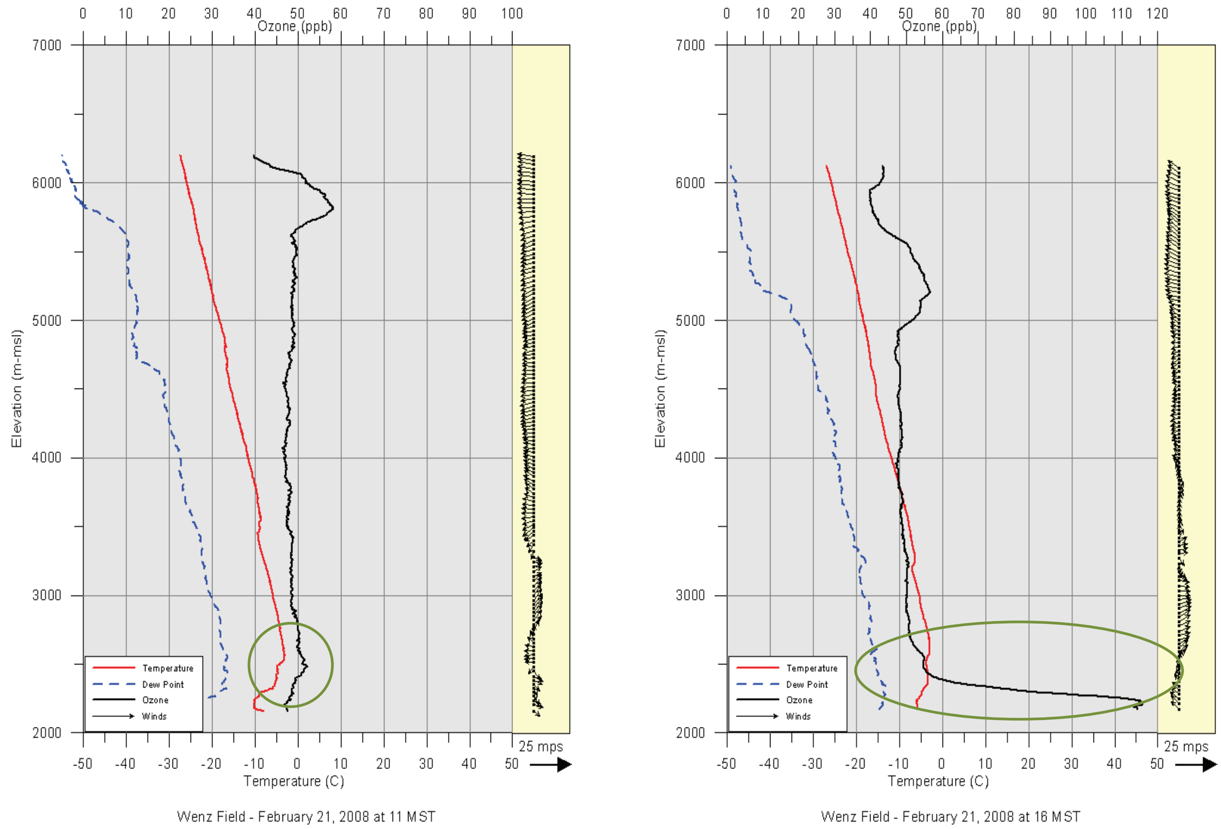


Figure S.7-10. February 21, 2008 balloon-borne soundings; Sounding at 11:00 (MST) (left); Sounding at 16:00 (MST) (right).

Tools to Evaluate Air Parcel Transport: HYSPLIT vs. AQplot Back Trajectory Analyses

Trajectory analyses were used to determine possible air parcel transport into the UGRB during February 20, 2008, as a means of evaluating possible precursor emissions and ozone transport in the UGRB and at the Boulder and Jonah monitors.

The HYSPLIT (HYbrid Single-Particle LaGrangian Integrated Trajectory) model is a trajectory model that is used for computing simple air parcel trajectories. HYSPLIT can use meteorological data from several archived meteorological modeling databases, including the NCEP Eta Data Assimilation System (EDAS), which is based on a 40 kilometer resolution data (2004-present). However, 40 kilometer (km) data may not provide sufficient resolution to resolve the significant terrain features that influence the wind flow patterns in the UGRB. The result of using such low resolution data to represent the terrain features in and surrounding the UGRB will be that the modeled terrain will be much smoother, and will not match the actual terrain (see Figure S.7-11). This will affect the wind trajectory analysis because the roughness of the terrain as well as terrain blocking and channeling effects may not be well represented, which would otherwise influence the wind speeds and the trajectory path lengths. In very complex terrain, such as in the UGRB, the HYSPLIT model trajectories may not be very accurate unless the local wind flow patterns are being driven by the large-scale synoptic conditions (e.g., strong winds).

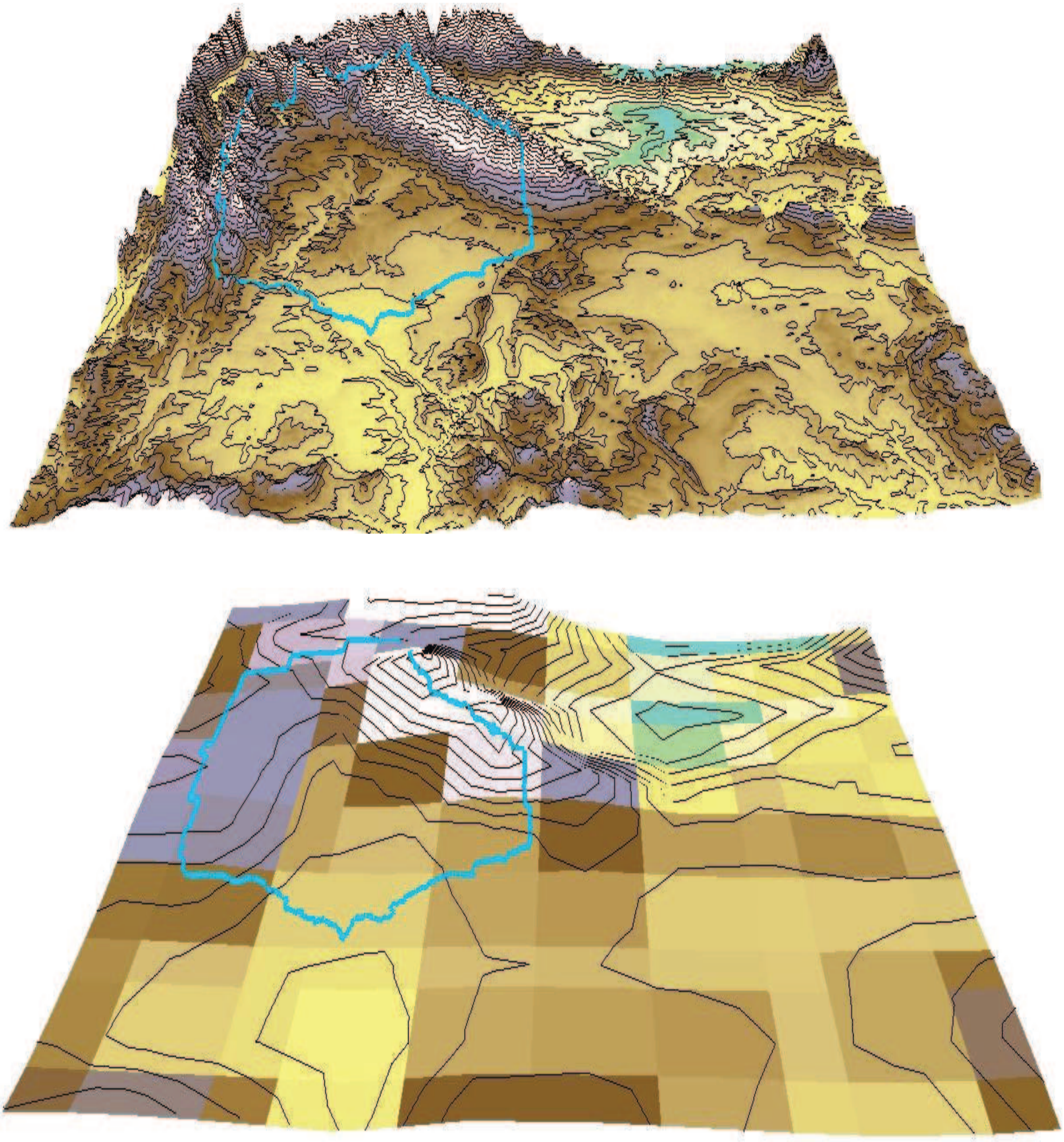


Figure S.7-11. A comparison of the local terrain features at 1 km and 40 km resolution, respectively, and the resulting "smoothed" terrain as shown in the 40 km 3-D topographic plot.

Figure S.7-12 shows a similar comparison of the local terrain features at 1 km and 40 km resolution as depicted in the 2-dimensional contour plots. Note the terrain features in the bottom pane are much less resolved (less terrain detail and decreased roughness) than those terrain features as shown in the top pane.

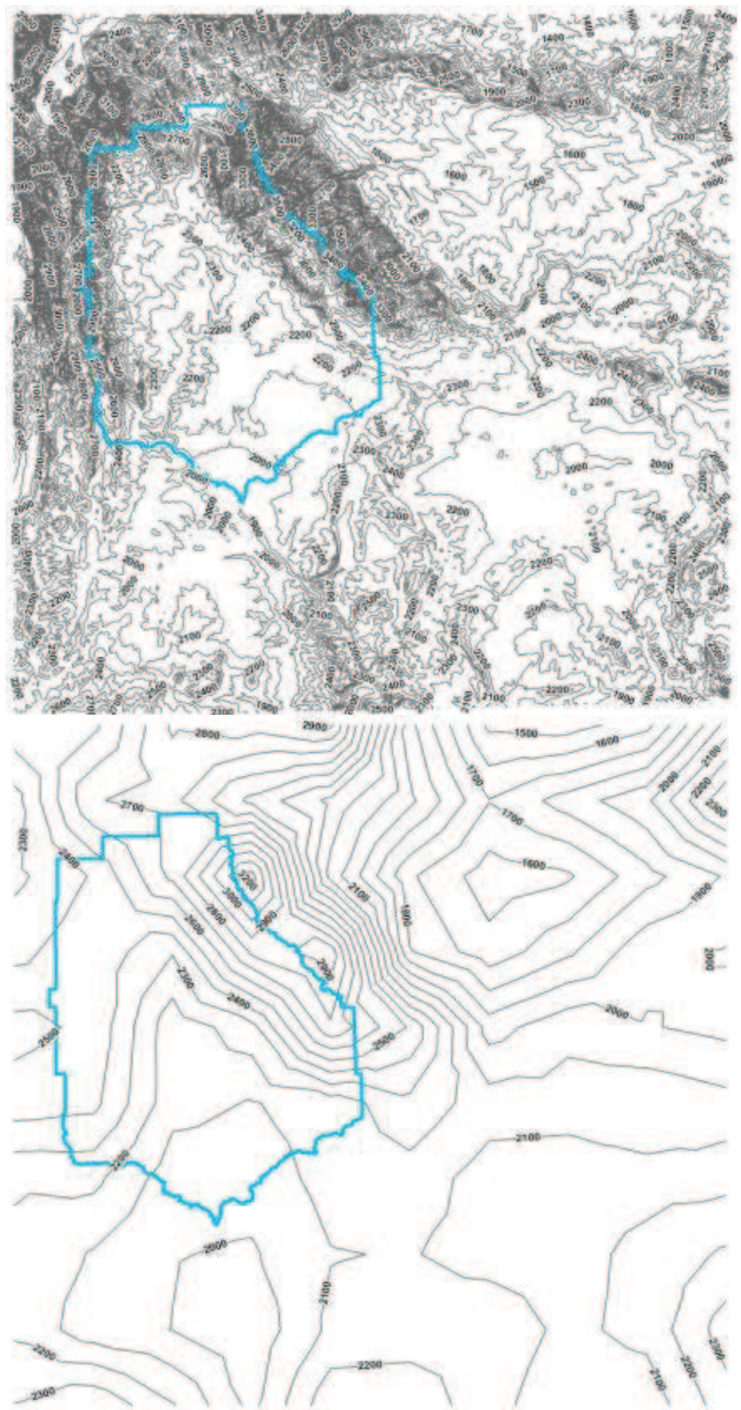


Figure S.7-12. A comparison of the local terrain features at 1 km and 40 km resolution, respectively, as depicted in the 2-D contour plots.

While the trajectory model is a useful tool in assessing approximate air parcel movement, and can be used to better understand potential pathways for pollutants moving within and into and out of the UGRB, trajectories are a highly simplified representation of the complex, two- and three-dimensional transport and turbulent diffusion processes that move pollutants from place to place. Thus, a particular trajectory path is subject to uncertainty and should not be interpreted as an exact representation of actual pollutant transport. Generally, the longer an air mass is tracked forward or backward in time, the more uncertain is its position (Kuo et al., 1985; Rolph and Draxler, 1990; Kahl and Samson, 1986).

Additionally, the trajectory model error is a function of the complexity of the meteorological scenario under study. In this analysis, the strong surface-based inversion layer in place on February 19-22, 2008 results in a decoupling of the upper air layers (above the inversion layer) and the lower air layers (below the inversion) and winds in the upper and lower layers will at times blow in different directions at different speeds. Winds are light and variable in the lower layer, adding to the complexity of the situation. This very complex meteorological scenario is difficult to represent accurately in a trajectory model.

AQD ran a comparison of 12-hour back trajectories from the Jonah and Boulder monitoring sites, using the HYSPLIT model with the EDAS 40 kilometer meteorological data, and AQplot, (a 2-dimensional trajectory model) using actual meteorological data from the Jonah and Boulder monitoring sites, respectively. This comparison shows that much different back trajectories are produced by these two models, as shown in Figures S.7-13 and S.7-14. The 2-dimensional trajectory model (AQplot), used in these analyses, was developed by the Texas Commission on Environmental Quality.

Additional trajectory analyses using a 3-D trajectory model are discussed in the next section. However, for this particular comparison, a 2-D trajectory model is an acceptable model to assess trajectories near the monitoring sites because the surface winds in the UGRB under these episodic winter conditions have been effectively decoupled from the upper air layers. The amount of vertical air movement is limited due to the capping inversion in place – in other words, the movement of air parcels below the inversion is not influenced by winds above the inversion, and there is little vertical mixing of air near the ground. Monitoring data of the localized meteorological patterns in the proposed nonattainment area boundary show that under these episodic conditions, the wind patterns are 2-dimensional, and the use of the 2-D AQplot trajectory model for this particular application is reasonable under these winter meteorological conditions (inversion, low mixing height, and stable atmosphere) as the air parcel trajectories start off and tend to stay close to the ground.

As shown in Figures S.7-13 and S.7-14, the resulting short trajectories never get very far away from the monitor site; considering the short duration of the trajectory analysis, less interpolation error would be expected. The HYSPLIT model does not consider the wind influences as measured in the 2008 field study surface monitoring network; the AQplot local-scale back trajectories are a more accurate depiction of what is going on because of the input of local data.

Figure S.7-13. Comparison of HYSPLIT (red) and AQplot (pink) 12-hour back trajectories from the Boulder monitoring site on February 20, 2008.

Figure S.7-14. Comparison of HYSPLIT (red) and AQplot (green) 12-hour back trajectories from the Jonah monitoring site on February 20, 2008.

This comparison demonstrates that the HYSPLIT model overestimates the back trajectory path length because the localized low wind speed conditions and the wind flow reversal are not reproduced in 40 kilometer EDAS meteorological analysis fields. Additionally, the HYSPLIT model trajectory shows a less dramatic shift in wind direction and much higher wind speeds leading to a completely different result. A trajectory model that accurately reflects the terrain influence, sustained low wind speeds, and local-scale observed wind flow patterns was needed to effectively evaluate air parcel transport throughout the UGRB under these episodic conditions.

AQplot Back Trajectory Analysis

Back trajectories using the AQplot model and the meteorological data collected during the field study on February 20, 2008 are shown in Figure S.7-15; the trajectories were used to evaluate air parcel movement near the monitors during the 12 hours leading up to the February 20, 2008 monitored high ozone concentrations. These back trajectories start at 2:00 pm (MST), and show that the wind patterns leading up to the afternoon high monitored ozone concentrations at the Boulder monitoring site (and other monitors in close proximity to the Boulder monitor) produce short trajectories, with the air parcels remaining in close proximity to these monitors during this 12-hour period, due to the observed low wind speeds and recirculation patterns (wind reversals).

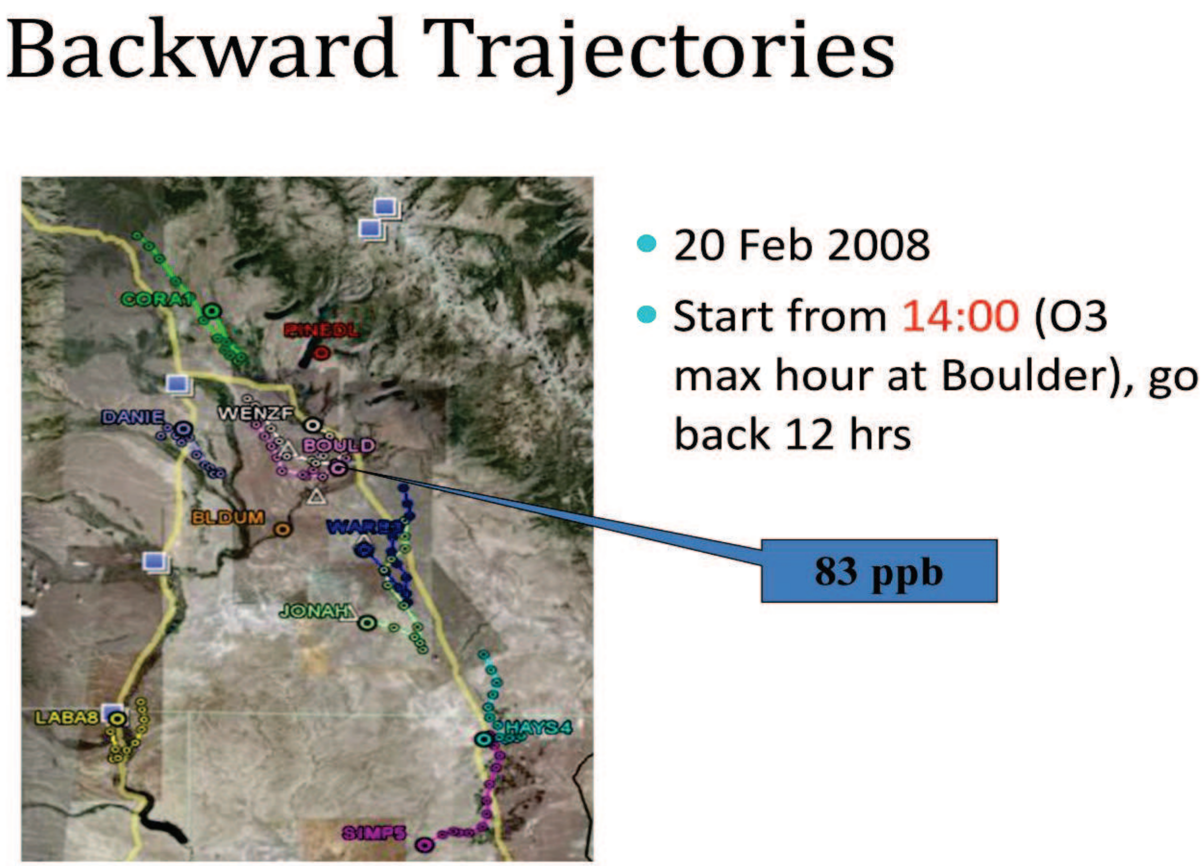


Figure S.7-15. 12-hour back trajectories near field study monitors on February 20, 2008.

Due to the complexity of the winds in the UGRB during February 19-23, 2008, including the significant terrain-dominated effects on localized winds, stable conditions, and wind flow reversals, as discussed, and the terrain-dominated regional meteorology outside of the UGRB, a high resolution 3-dimensional (3-D) wind field was needed that could correctly reproduce:

1) Shallow inversions and near-field wind flow patterns as measured at the SODAR, which is near the Boulder monitor; and
2) Regional-scale wind flow patterns.

This particular wind field would be utilized in conjunction with a full 3-D trajectory model to evaluate:

1) Air parcel movement in the study area;
2) Influences from the surrounding regional terrain on air parcel movement;
3) Air parcel inflow (ozone or precursor emissions transport) into Sublette County on the days leading up to and during the February 19-23, 2008 ozone episode.

AQD contracted out the development of a 3-D CALMET wind field to evaluate the above, which is discussed in the following section.

CalDESK Trajectory Analysis

AQD developed a high resolution (spatial and temporal) 3-dimensional wind field that uses the National Center for Environmental Prediction (NCEP) Rapid Update Cycle (RUC) model at 20 kilometer resolution, coupled with the high resolution observational database of surface and upper air meteorological data measurements obtained during the 2008 field study. It should be noted that the terrain elevation data used in this wind field is based on much higher terrain resolution than is currently used in the HYSPLIT model. The RUC and field meteorological data were processed through the CALMET diagnostic wind model to generate a 1 kilometer gridded wind field, using high resolution terrain and land use/land cover data, and actual observations of daily snow cover to account for actual snow cover (and albedo effects) within the CALMET domain. The complexity of the terrain, as represented in this 3-dimensional (3-D) CALMET wind field in shown in Figure S.7-16.

This CALMET wind field was developed to evaluate the ozone episode-specific meteorology associated with the February 18-23, 2008 ozone episode. The CALMET domain was set up using the same meteorological modeling domain (464 km x 400 km) developed for the Southwest Wyoming Technical Air Forum (SWWYTAF) modeling analyses (1999), with increased vertical resolution to total 14 vertical layers; the lower layers having small vertical depths in order to better resolve complex flow patterns and temperature inversions near the surface.

Figure S.7-17 provides a snapshot of the wind field based on the winds at 4:00 am (MST) on February 20, 2008, and shows the complexity of the terrain surrounding the UGRB is very well represented in the CALMET wind field. The wind field captures the strong terrain-dominated down slope winds during the early morning hours, and the strong channeling and drainage effects which are exhibited throughout the UGRB – CALMET "sees" the influence of the terrain.

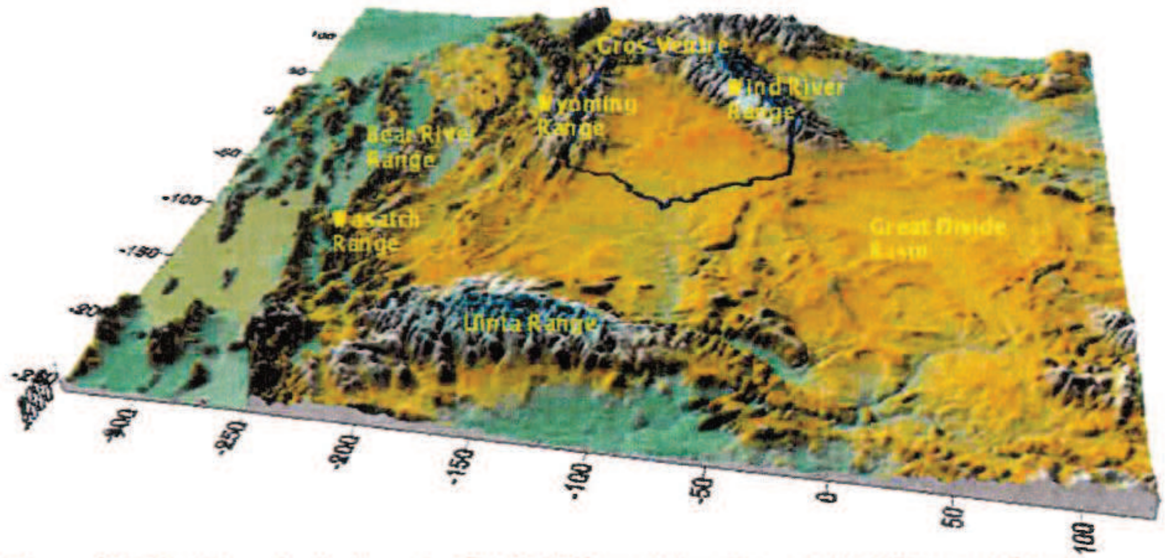


Figure S.7-16. Terrain features in CALMET modeling domain (464 km x 400 km).

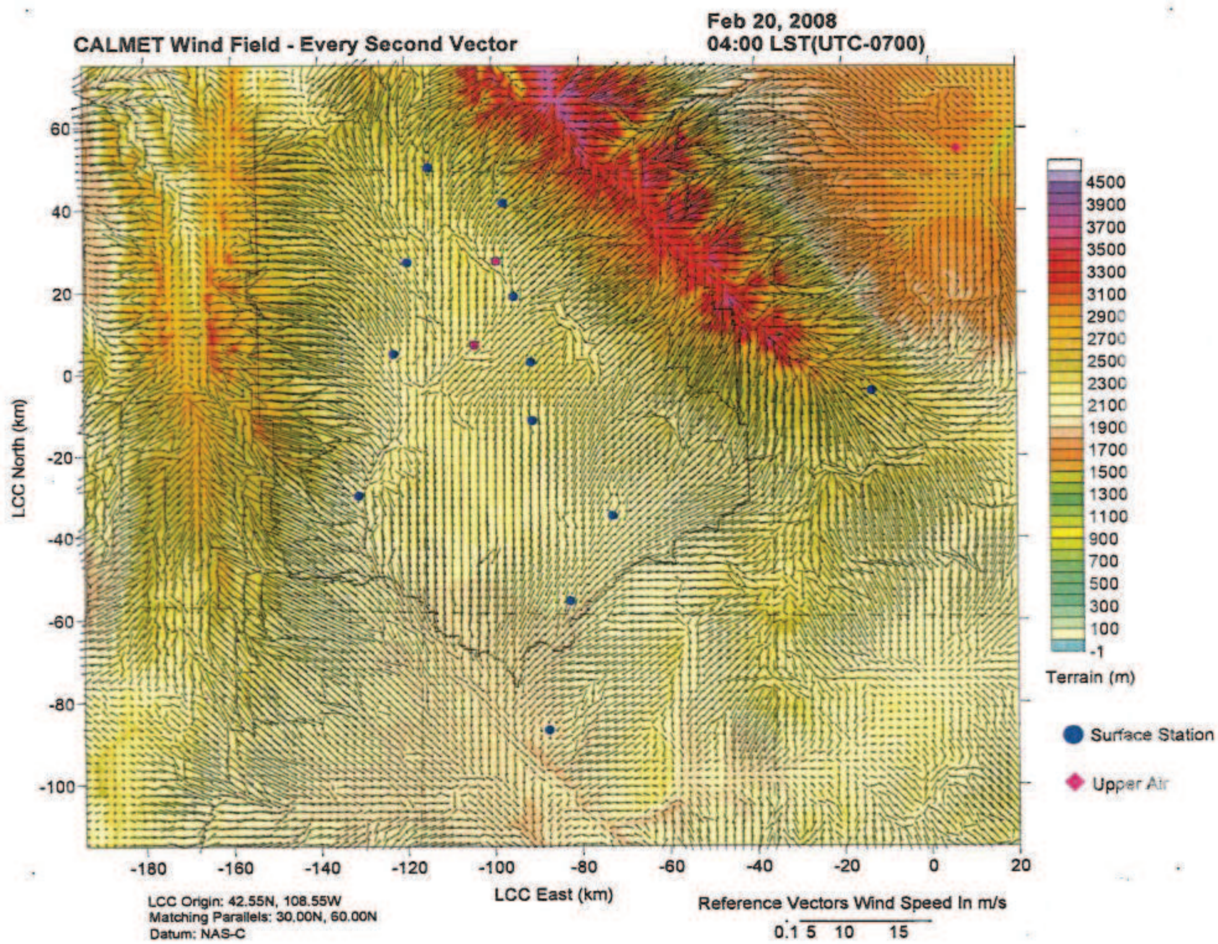


Figure S.7-17. CALMET wind field at 4:00 am (MST) on February 20, 2008. The 2008 field study meteorological monitoring sites are shown for reference.

The 3-D CALMET wind field accurately depicts meteorological conditions in the UGRB and surrounding area. A detailed report discussing the development of the CALMET wind field and the validation of the wind field compared to observations, entitled, "Upper Green River Winter Ozone Study: CALMET Database Development Phase I" will be posted on the DEQ web site and will be sent under separate cover to EPA shortly. Validation of this wind field has shown that the local-scale observed meteorological conditions are being reproduced:

- Temperature lapse rates associated with inversion conditions and low mixing heights
- Wind speeds and wind reversals
- Duration of down slope winds, which last until approximately mid-day before reversing to a generally southeasterly wind flow pattern

The trajectory analyses using this wind field lead to the conclusion that regional transport is insignificant, and local-scale precursor emissions transport is the dominant means of precursor transport during the high ozone periods. The trajectory analyses that follow were a key factor in selection of an appropriate southern boundary of the nonattainment area. The trajectory analyses demonstrate that the proposed southern boundary of the nonattainment area is reasonable, and that there is no significant contribution of ozone or ozone precursors from areas or sources outside the proposed nonattainment area during elevated ozone events.

Specific Examples of Trajectory Analyses Using CalDESK

Based on this wind field, AQD used the CalDESK visualization software to run forward trajectory analyses to evaluate air parcel transport into and out of the UGRB, specifically with respect to air parcels from large stationary sources (power plants and Trona plants) located to the south of the UGRB, and to evaluate the southern extent of air parcel inflow into the UGRB. A series of CalDESK forward trajectory analyses follow, along with a brief discussion of the resulting trajectories generated by CalDESK during February 18-23, 2008. CalDESK Forward Trajectory Analyses (FTA) for February 18, 2008 are shown in Figures S.7-18 through S.7-22.

NOTE: Trajectory figures (Figures S.7-18 through S.7- 49) are being updated to show the proposed nonattainment area boundary. Those figures will be available shortly. AQD will send those figure to EPA as replacement pages.

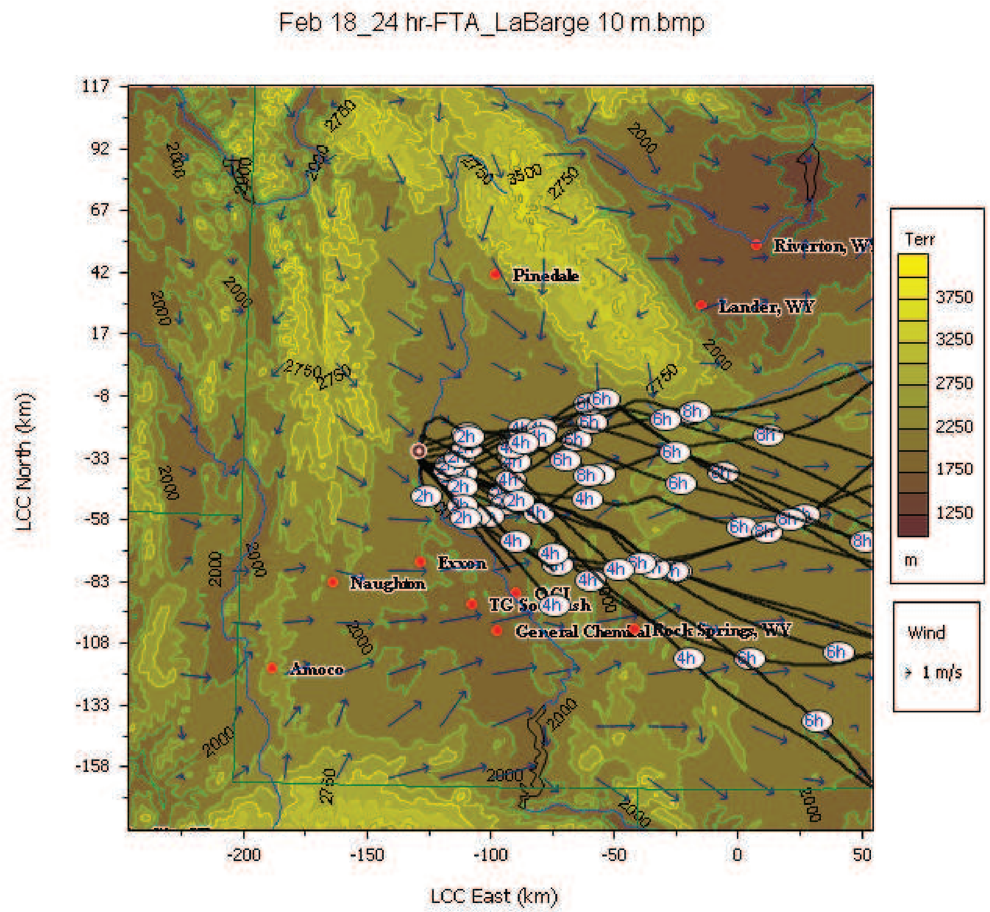


Figure S.7-18. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 18, 2008.

As shown in Figures S.7-18 through S.7-22, the prevailing northwest winds within the UGRB on this day limit air parcel transport into the UGRB from sources located south of Sublette County, which is reflected in the trajectory analysis for the LaBarge and Moxa Arch areas, the Naughton power plant, the OCI Trona processing facility, and the Bridger power plant. Additionally, the wind speeds at the monitoring sites on the Pinedale Anticline were also generally high and reflect the prevailing northwest winds typical of the study area during most of the year. This moderately strong, organized northwest flow does not extend to the field study southern monitoring sites (Haystack Butte and Simpsons Gulch); these southern monitoring sites experienced a generally westerly wind. The 2008 field study monitoring sites are shown in Figure S.7-1.

Wind speeds were generally high throughout the monitoring network on February 18th. These conditions continued throughout the night until the early morning of February 19th. Winds decreased significantly thereafter becoming light and variable for the remainder of the day, setting the stage for the next several days. Ozone levels were relatively low, in the 50 ppb range on February 18th; increasing on February 19th, with both the Boulder and Jonah monitoring sites experiencing 8-hr peaks of 80 ppb.

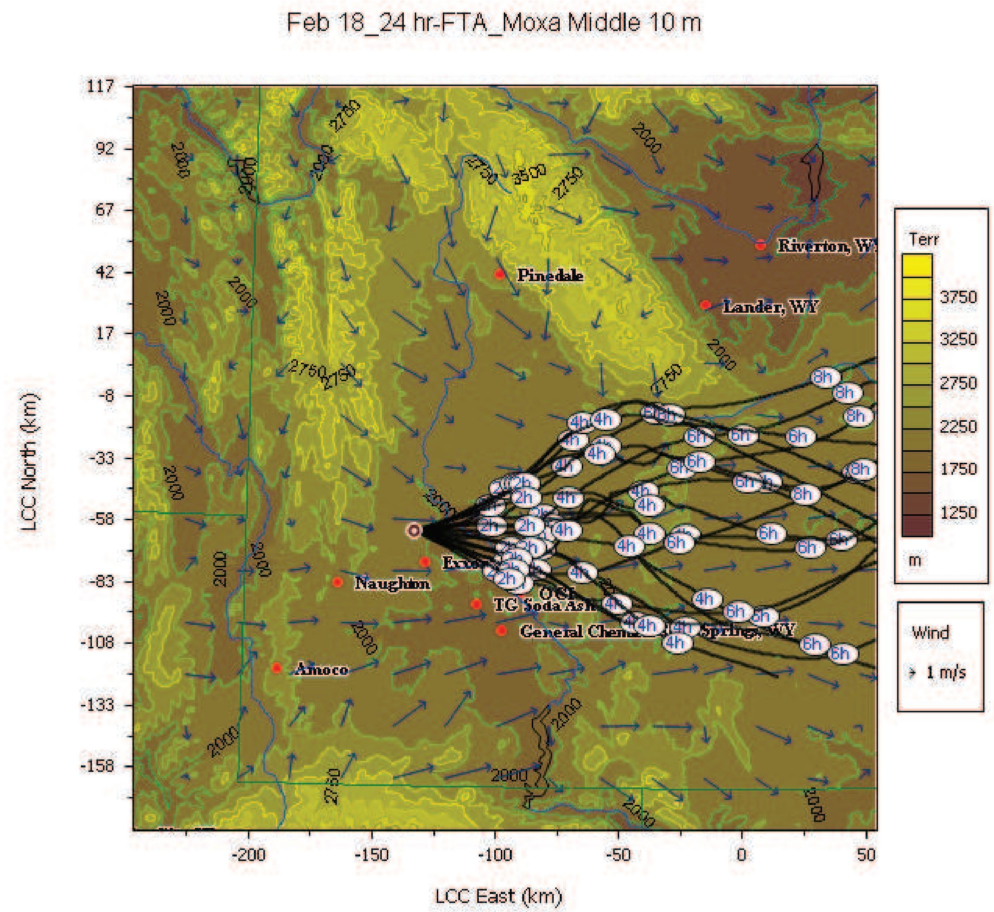


Figure S.7-19. 24-hour forward trajectory analysis in the Moxa Arch area on February 18, 2008.

The trajectory analysis shown in Figure S.7-19 places the initial air parcel release point in the northern part of the Moxa Arch field. The predominant paths shown trend to the east, and there is a slight northerly component to several of the modeled trajectories. These trajectories generally parallel the southern boundary of the proposed nonattainment area along Pacific Creek. While some of the trajectory paths lie within the proposed nonattainment area, none of the paths indicate that sources within the Moxa Arch cause or contribute to elevated ozone levels within the proposed nonattainment area.

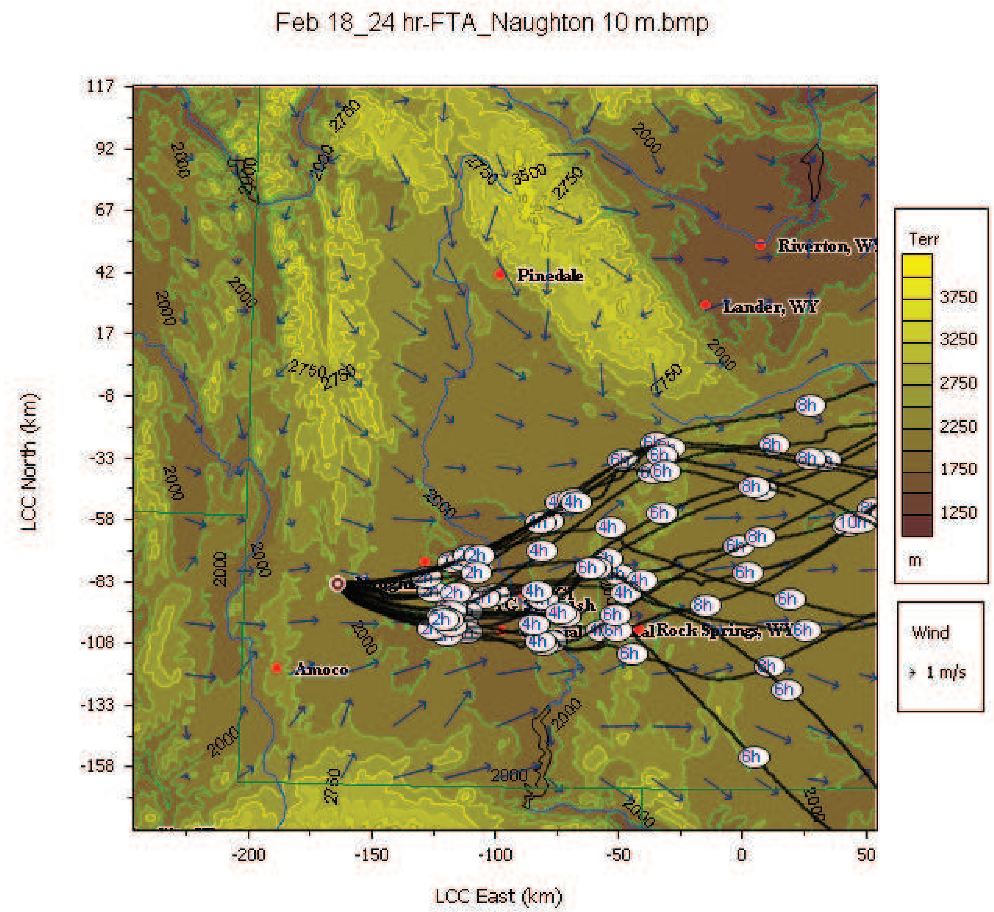


Figure S.7-20. 24-hour forward trajectory analysis at Naughton power plant on February 18, 2008.

The trajectory analysis in Figure S.7-20 shows all modeled trajectories from Naughton not entering the proposed nonattainment area.

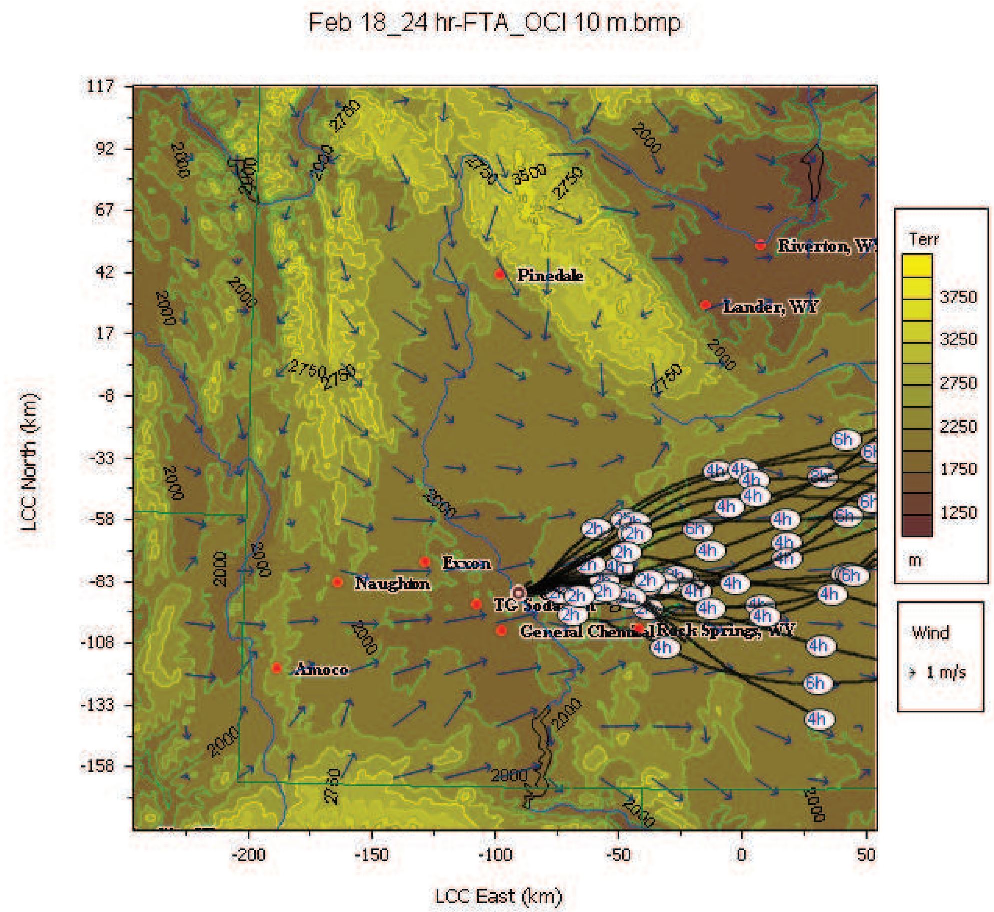


Figure S.7-21. 24-hour forward trajectory analysis at OCI Trona plant on February 18, 2008.

The trajectory analysis in Figure S.7-21 shows all modeled trajectories from OCI not entering the proposed nonattainment area.

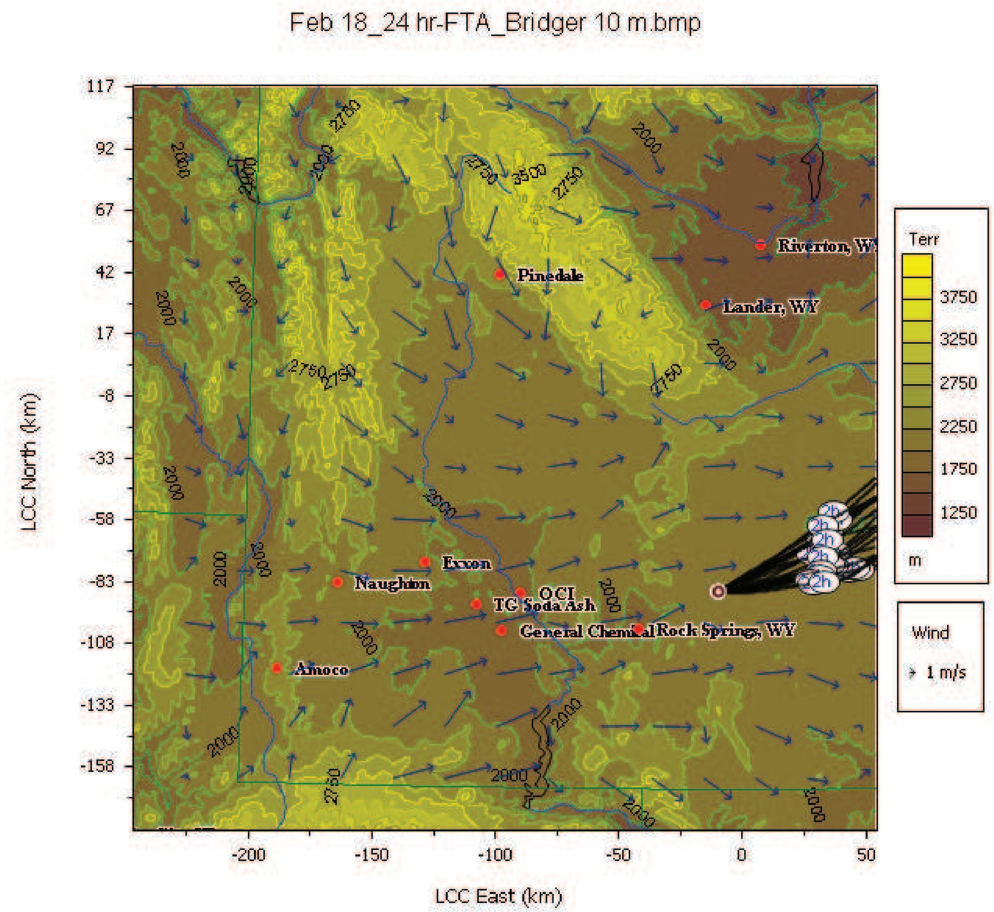


Figure S.7-22. 24-hour forward trajectory analysis at Bridger power plant on February 18, 2008.

The trajectory analysis in Figure S.7-22 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

CalDESK Forward Trajectory Analyses for February 19, 2008 are shown in Figures S.7-23 through S.7-29.

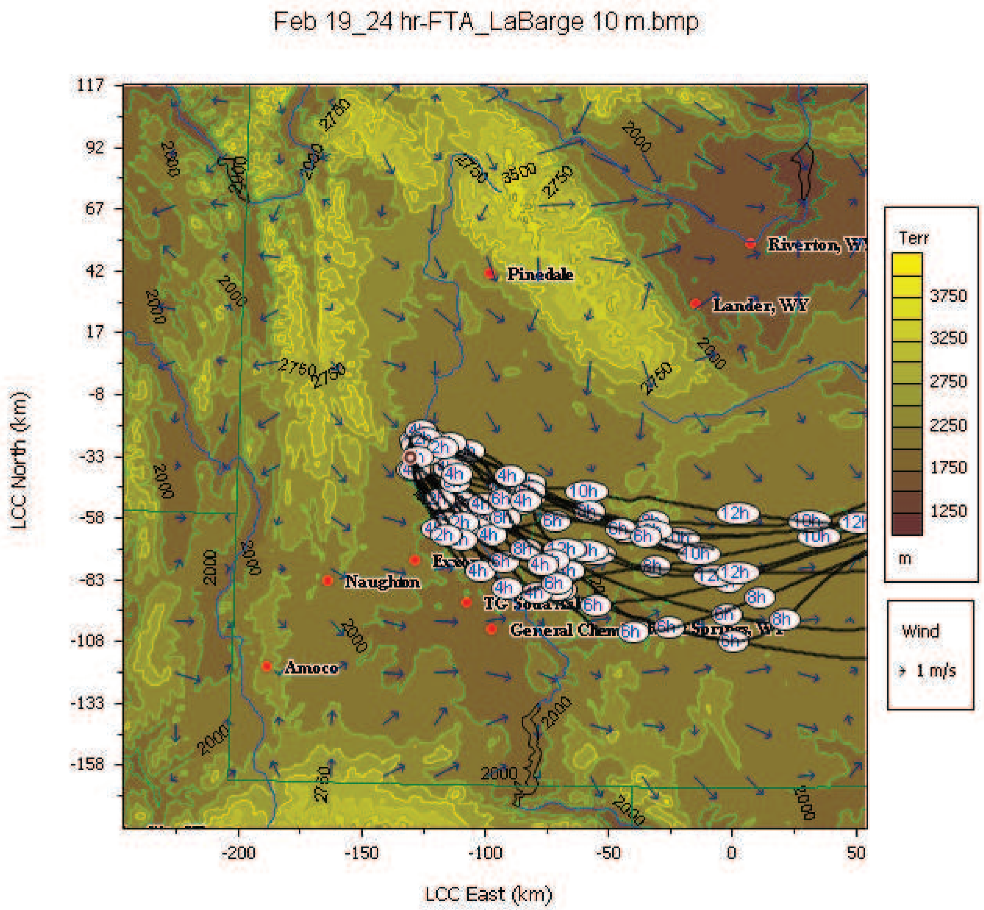


Figure S.7-23. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 19, 2008.

As shown in Figures S.7-23 through S.7-27, the prevailing northwest winds on February 19th continue to limit air parcel transport into the UGRB from the south, which is reflected in the trajectory analysis for the LaBarge and Moxa Arch areas, the Naughton power plant, the OCI Trona processing facility, and the Bridger power plant.

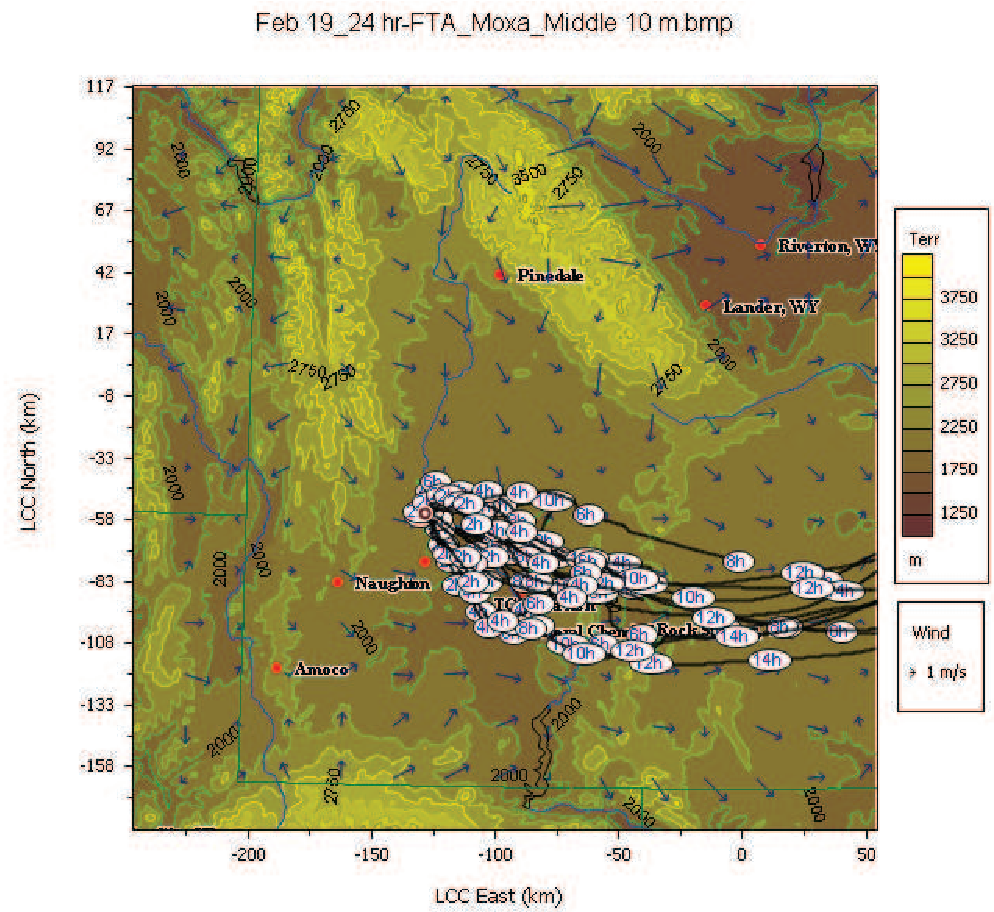


Figure S.7-24. 24-hour forward trajectory analysis in the Moxa Arch area on February 19, 2008.

The trajectory analysis in Figure S.7-24 shows all modeled trajectories from Moxa Arch not entering the proposed nonattainment area.

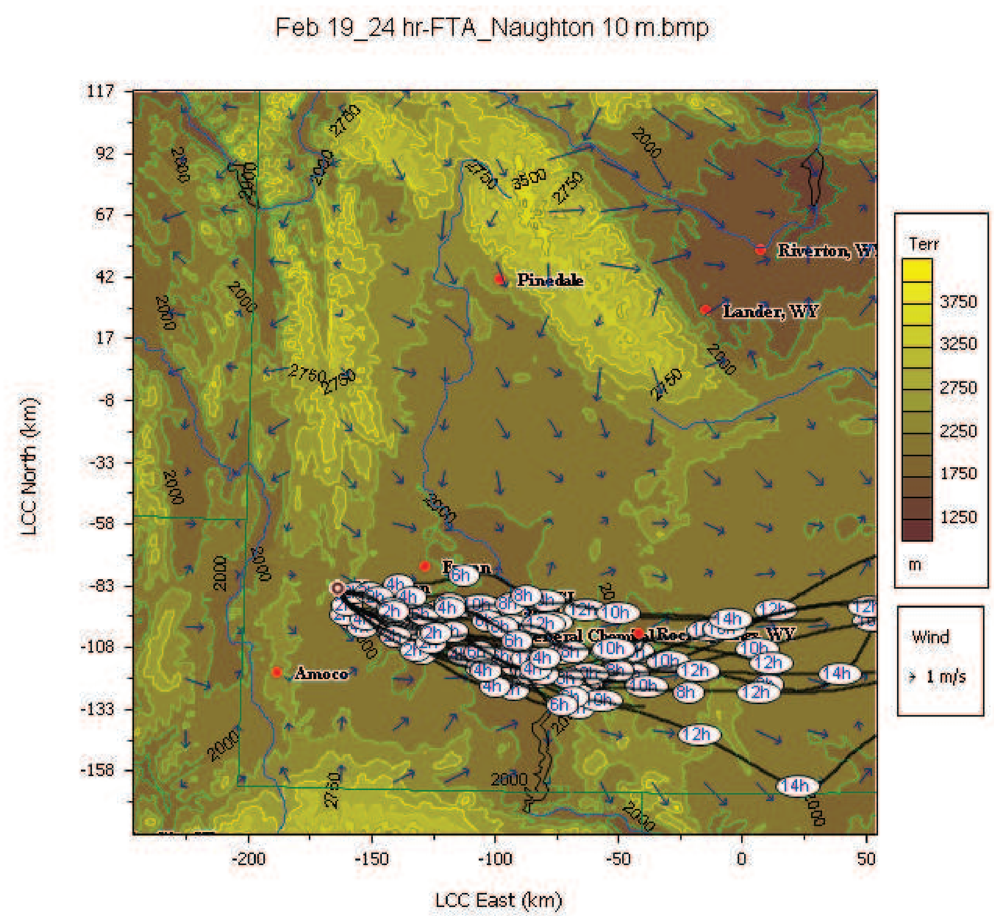


Figure S.7-25. 24-hour forward trajectory analysis at Naughton power plant on February 19, 2008.

The trajectory analysis in Figure S.7-25 shows all modeled trajectories from Naughton not entering the proposed nonattainment area.

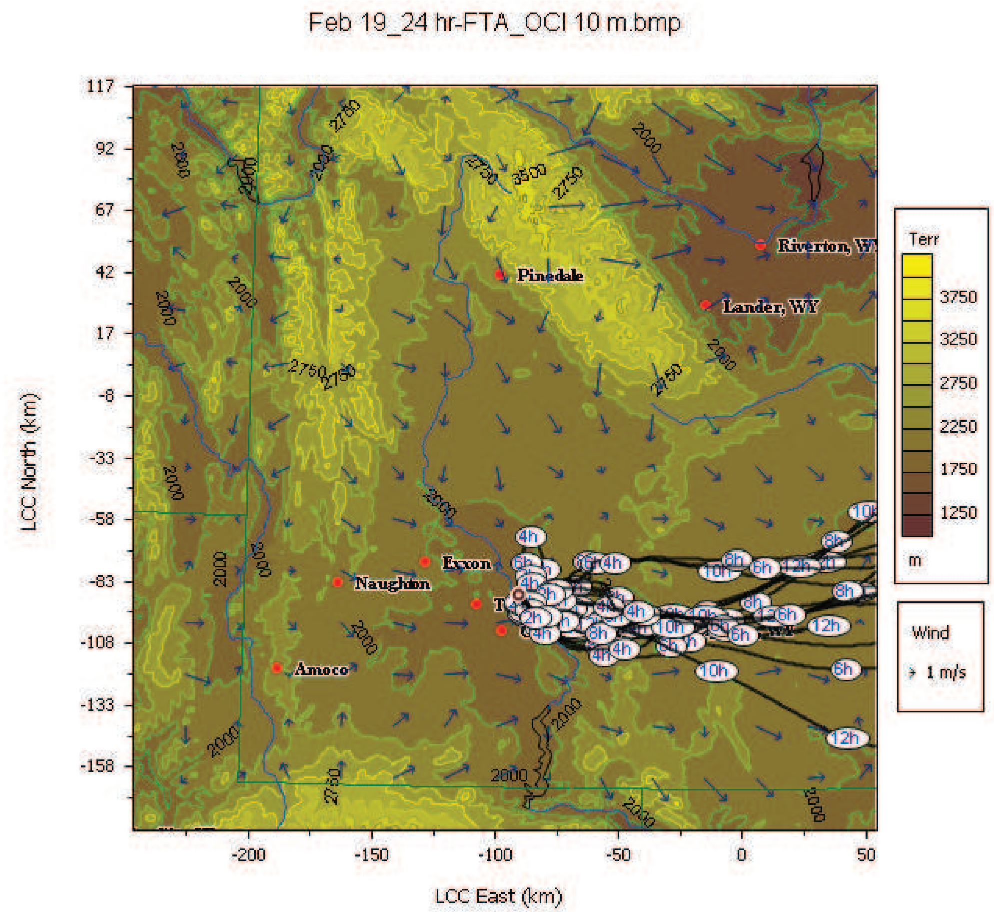


Figure S.7-26. 24-hour forward trajectory analysis at OCI Trona plant on February 19, 2008.

The trajectory analysis in Figure S.7-26 shows all modeled trajectories from OCI not entering the proposed nonattainment area.

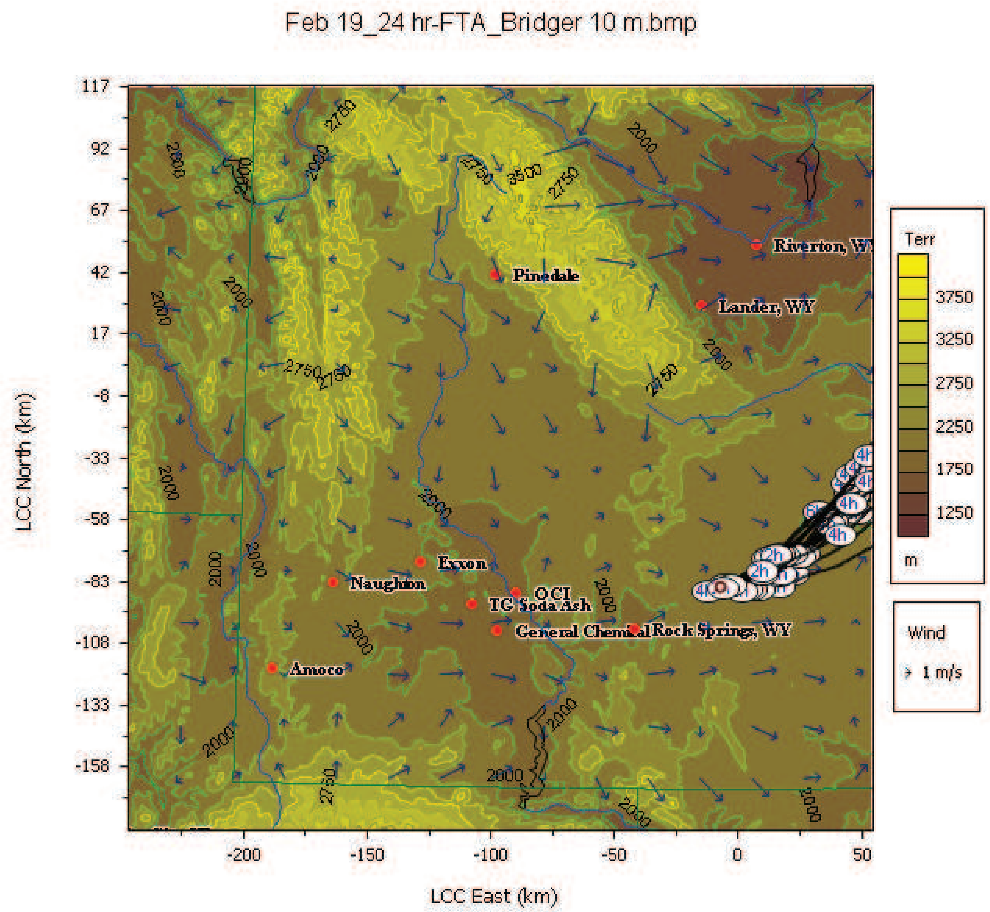


Figure S.7-27. 24-hour forward trajectory analysis at Bridger power plant on February 19, 2008.

The trajectory analysis in Figure S.7-27 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

CalDESK Forward Trajectory Analyses for February 20, 2008 are shown in Figures S.7-28 through S.7-32.

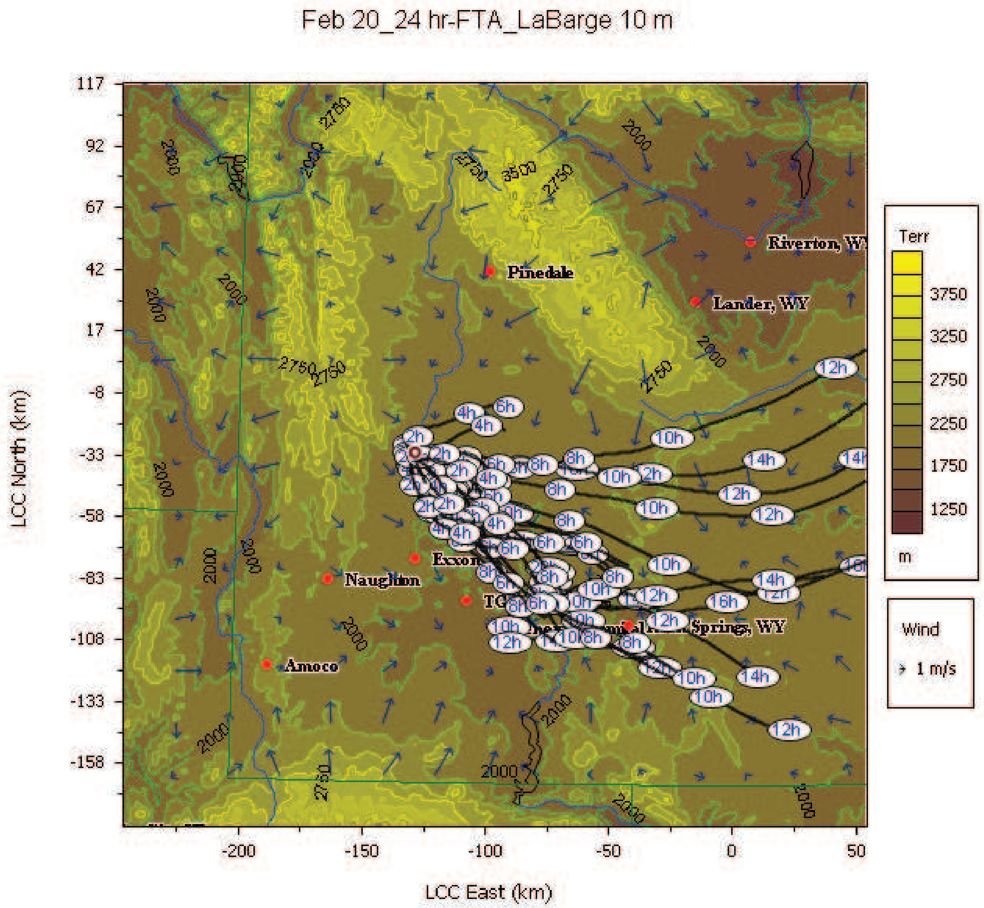


Figure S.7-28. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 20, 2008.

As shown in Figure S.7-28, on February 20, 2008, the trajectory analysis for the LaBarge area begins to exhibit a few possible trajectory paths into the area west of the Jonah oil and gas field, indicating some potential for upwind emissions transport at the Jonah monitor. Figures S.7-29 through S.7-32 show the prevailing northwest winds continue to limit southerly transport of emissions into the UGRB, along with the prevailing southwesterly winds along the Interstate-80 corridor, which are reflected in the trajectory analysis for the Moxa Arch area, the Naughton power plant, the OCI Trona processing facility, and the Bridger power plant.

It is important to note that as the trajectory start point is located further south, and out of the UGRB, the dominant northwest winds taper off, and the airflow at the south end of the UGRB mixes with the prevailing winds along the Interstate-80 corridor, which tend to dominate air parcel transport once the air parcel is out of the UGRB, south of the Wyoming Range terrain influence.

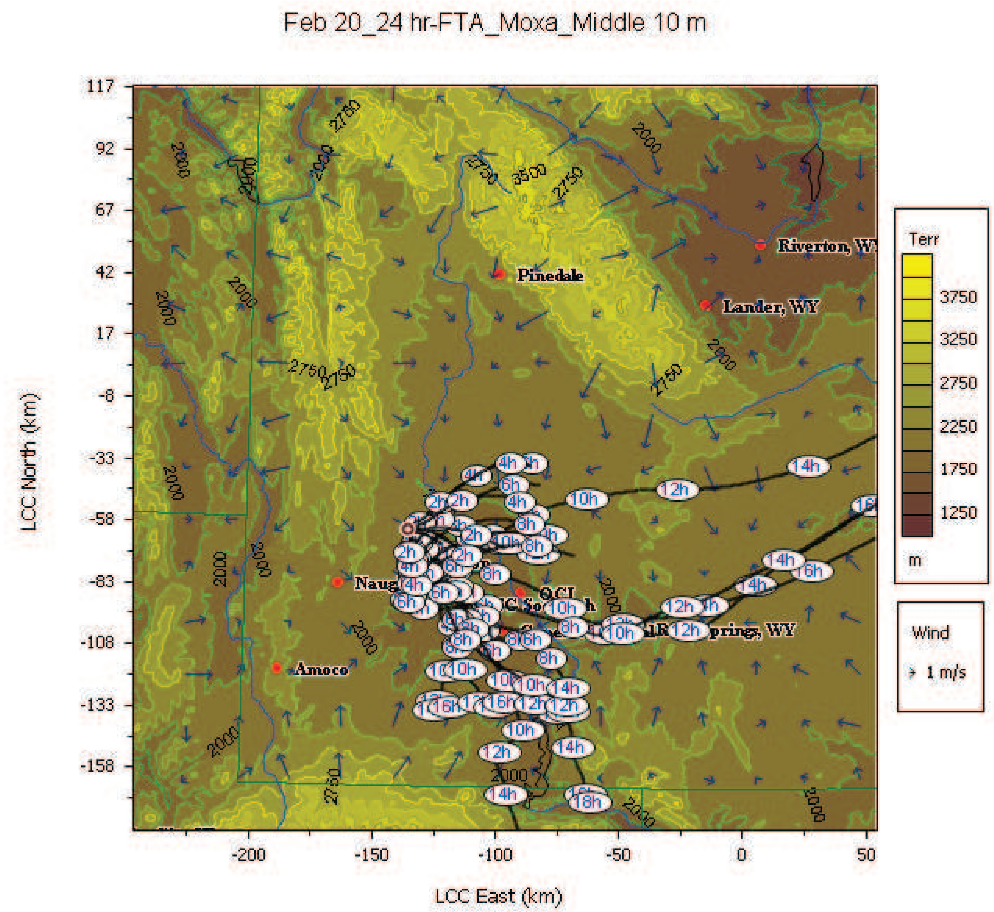


Figure S.7-29. 24-hour forward trajectory analysis in the Moxa Arch area on February 20, 2008.

The trajectory analysis in Figure S.7-29 shows all modeled trajectories from Moxa Arch not entering the proposed nonattainment area.

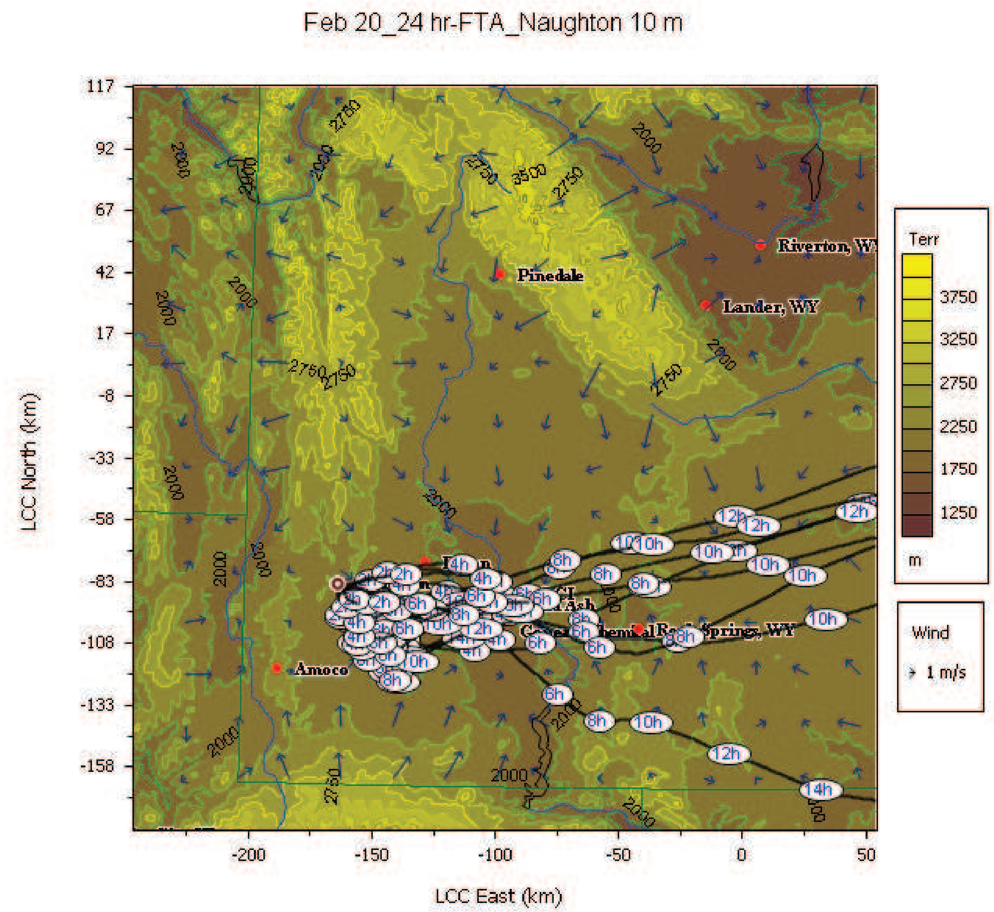


Figure S.7-30. 24-hour forward trajectory analysis at Naughton power plant on February 20, 2008.

The trajectory analysis in Figure S.7-30 shows all modeled trajectories from Naughton not entering the proposed nonattainment area.

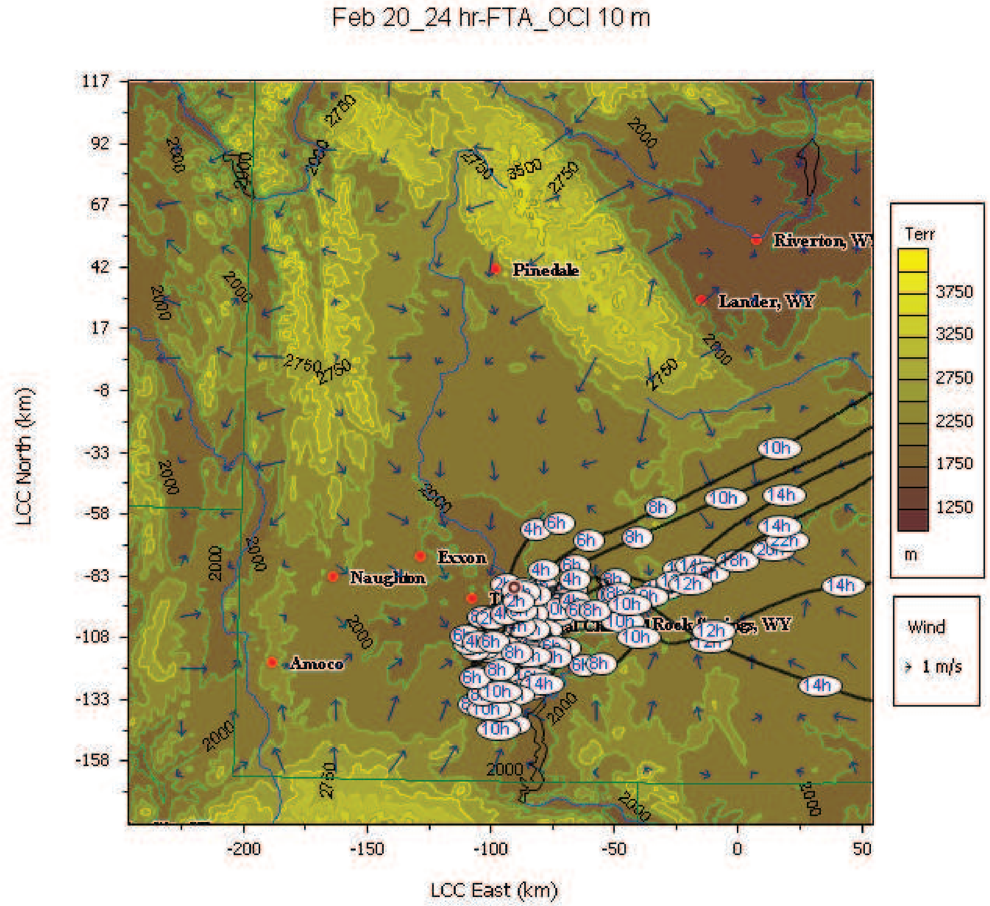


Figure S.7-31. 24-hour forward trajectory analysis at OCI Trona plant on February 20, 2008.

The trajectory analysis in Figure S.7-31 shows all modeled trajectories from OCI not entering the proposed nonattainment area.

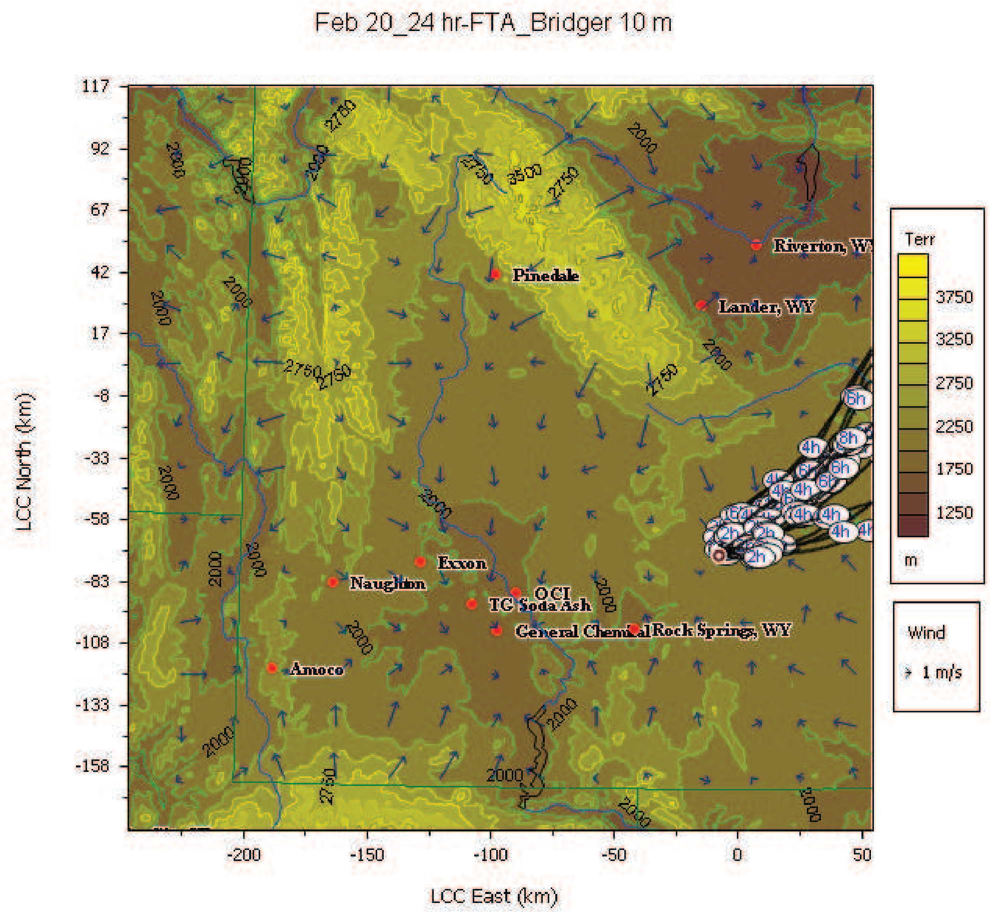


Figure S.7-32. 24-hour forward trajectory analysis at Bridger power plant on February 20, 2008.

The trajectory analysis in Figure S.7-32 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

CalDESK Forward Trajectory Analyses for February 21, 2008 are shown in Figures S.7-33 through S.7-37.

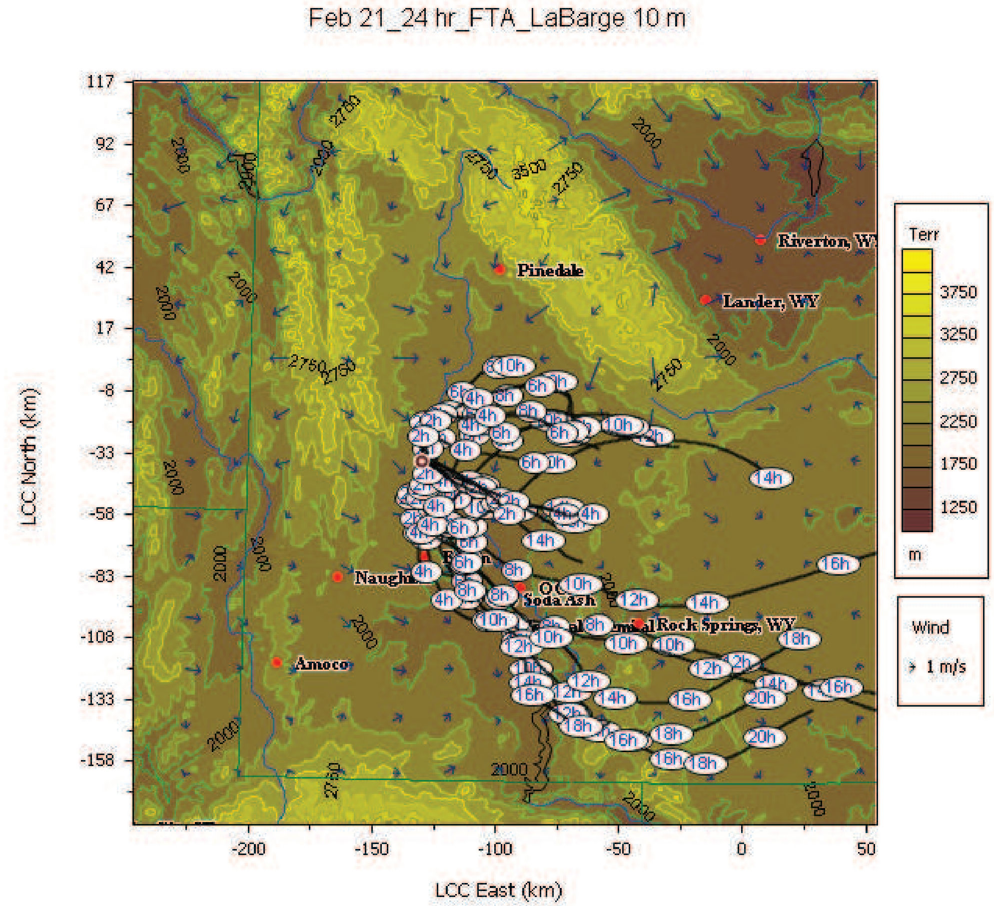


Figure S.7-33. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 21, 2008.

By the afternoon of February 21, 2008, the high pressure ridge had weakened, and had also flattened, and the central ridge axis was over or just east of southwestern Wyoming through the entire day; the resulting light wind stagnant situation also enabled the highest ozone production recorded at the Boulder monitoring site to date. These conditions were monitored during the first IOP, conducted February 18-21, 2008, in which a set of intensive meteorological and ambient measurements were collected when meteorological conditions similar to those associated with high ozone episodes during 2005 – 2006 had been forecast to occur during the 2008 field study.

The low level inversion was not quite as strong as on February 19, 2008, but it did stay intact through the entire daylight period, keeping ground level emissions trapped near the surface. With the very light and variable winds above the inversion, localized flow patterns near the ground level developed during the day allowing emissions to transport along those pathways.

As shown in Figure S.7-33, the trajectory analyses for the LaBarge area exhibit several possible air parcel paths to the northwest on February 21, 2008. Figure S.7-34 shows the trajectory analysis for the Moxa Arch area, which exhibits a few trajectories initially moving into the southernmost portion of the UGRB, but the strong northerly winds in the UGRB dominate the flow. This limits northward air parcel transport into the UGRB, and the vast majority of the trajectories continue to travel south out of the UGRB. The trajectory start point at Moxa Arch is approximately fourteen (14) miles south of the LaBarge trajectory start point, where the dominant northwest wind influence in the UGRB valley is tapering off, and mixes with prevailing westerly winds.

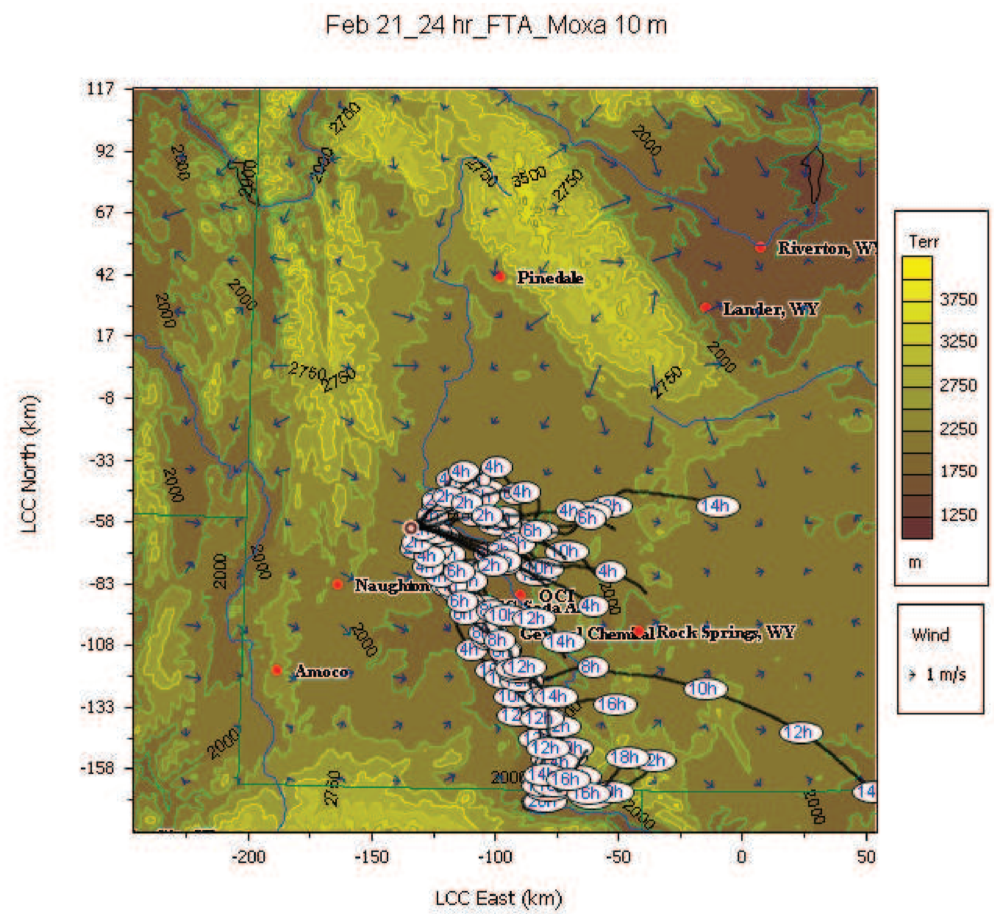


Figure S.7-34. 24-hour forward trajectory analysis in the Moxa Arch area on February 21, 2008.

Figure S.7-35 shows prevailing westerly winds at Naughton with air parcels moving eastward. The strong northwest winds in the UGRB and the terrain blocking effects of the Uinta Range to the south, collectively, influence the trajectory paths as they move from the Naughton power plant trajectory start point. The trajectory analysis in Figure S.7-35 shows all modeled trajectories from Naughton not entering the proposed nonattainment area

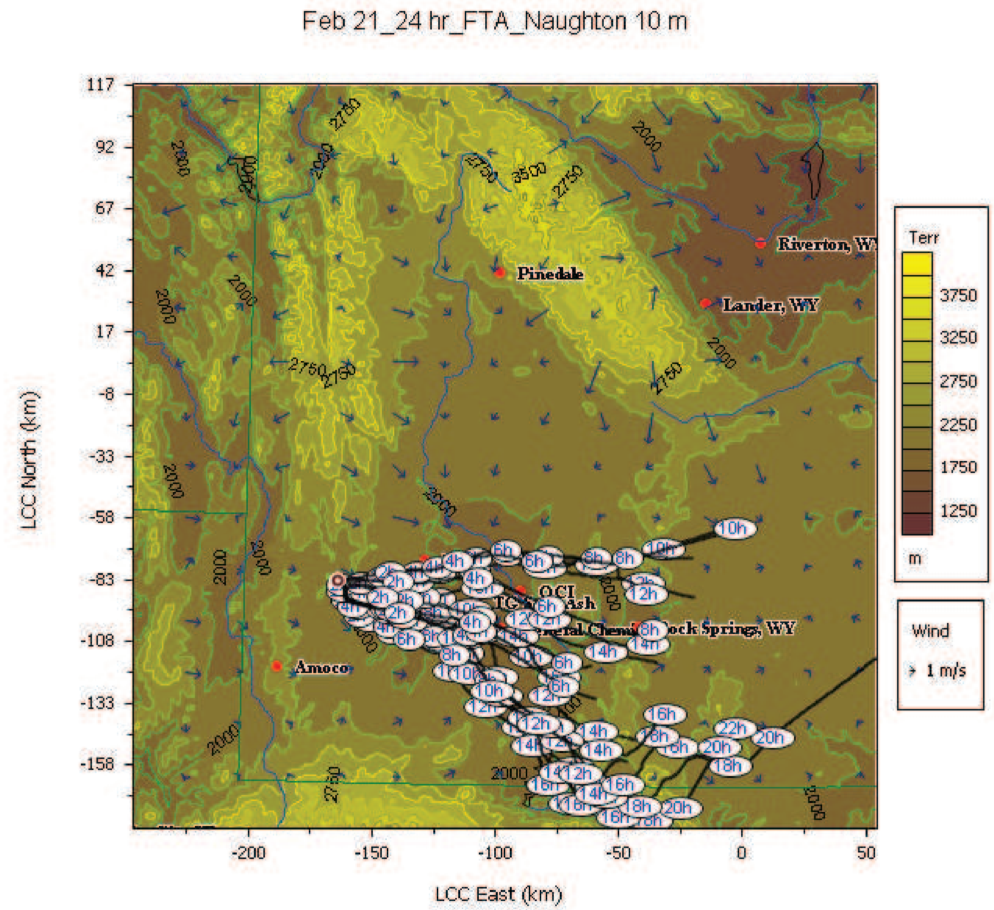


Figure S.7-35. 24-hour forward trajectory analysis at Naughton power plant on February 21, 2008.

Figures S.7-36 and S.7-37 show the prevailing westerly winds at the OCI Trona plant and the Bridger power plant, with the air parcels moving eastward and then northward. As noted with the forward trajectory paths from Naughton power plant, the strong northwest winds in the UGRB and the terrain blocking effects of the Uinta Range to the south continue to influence the trajectory paths as they move from the OCI and Bridger trajectory start points. The trajectory analysis in Figures S.7-36 and S.7-37 shows all modeled trajectories from OCI and Bridger not entering the proposed nonattainment area.

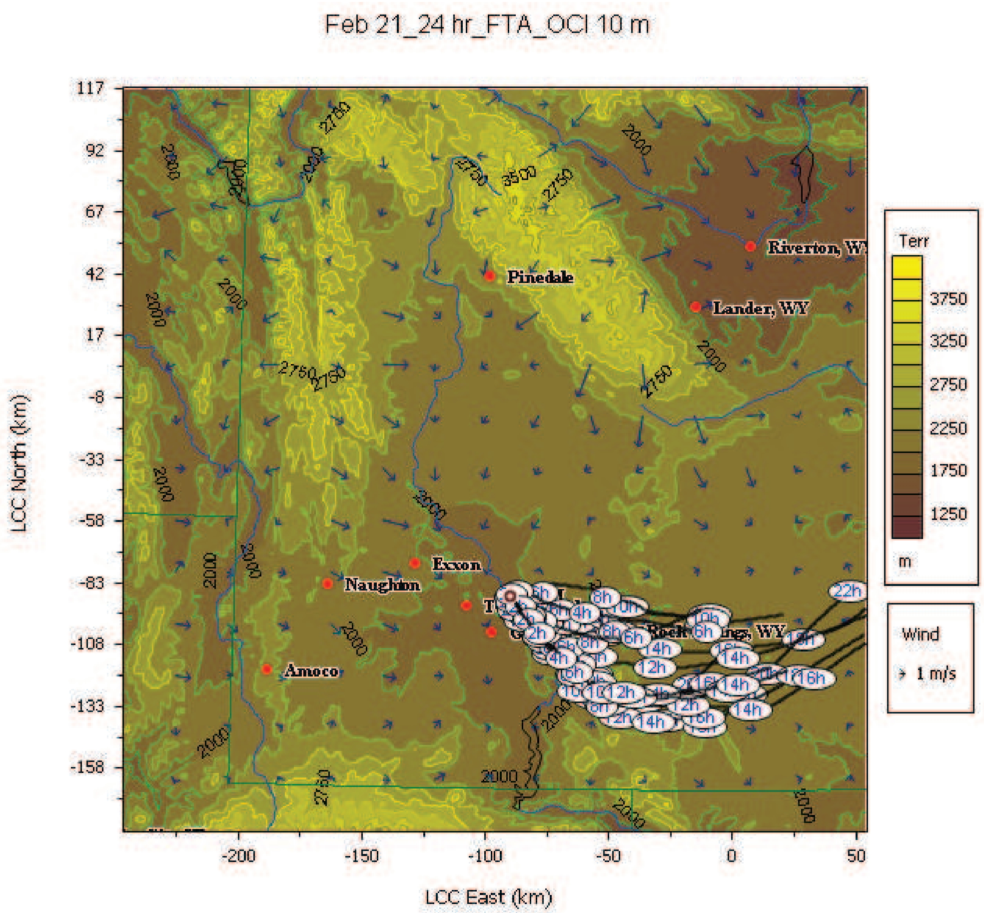


Figure S.7-36. 24-hour forward trajectory analysis at OCI Trona plant on February 21, 2008.

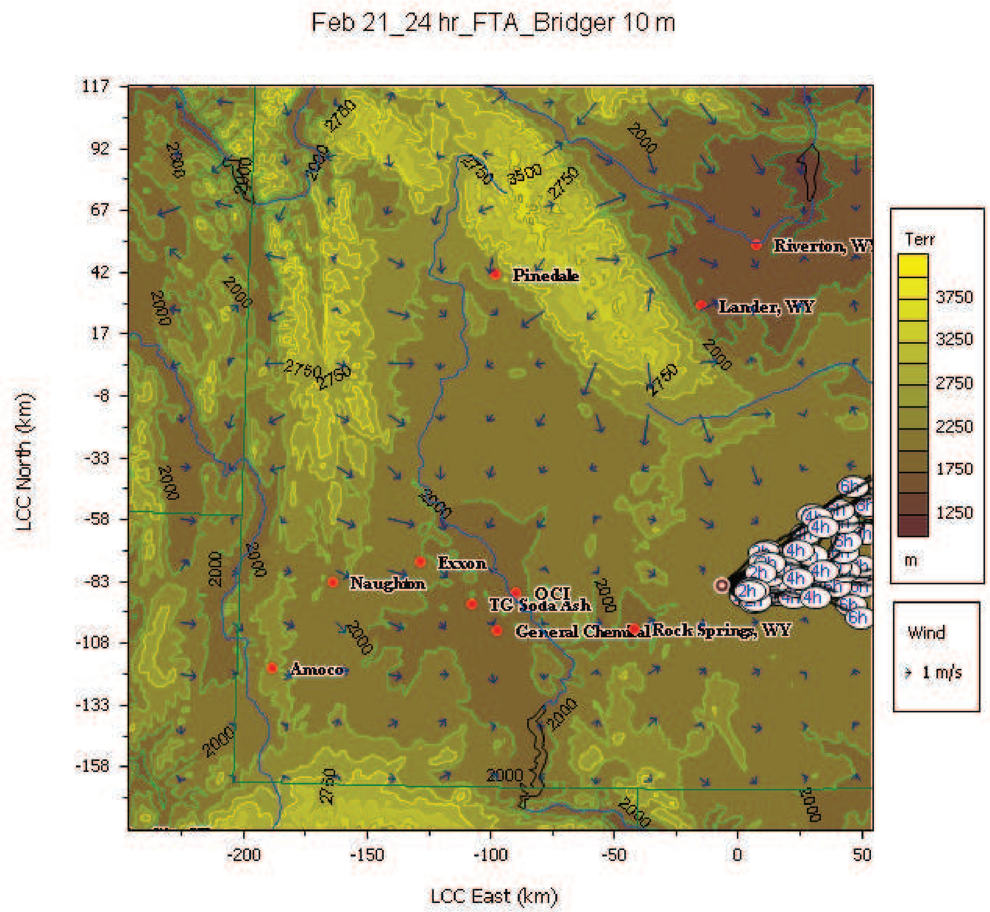


Figure S.7-37. 24-hour forward trajectory analysis at Bridger power plant on February 21, 2008.

As discussed previously, the localized meteorology within the UGRB during the ozone episodes influences air parcel movement within the UGRB, typically leading to shorter trajectory paths than if the trajectories were based on a start point located outside of the UGRB. CalDESK trajectory analyses that are initiated within the UGRB reflect the wind flow reversals and sustained low wind speeds; hence, shorter trajectory paths (and flow recirculation) are produced, which is consistent with the observed wind patterns.

During these wind reversals, the air flow changes direction. The winds are initially out of the northwest in the early morning, then out of the northeast, and then turn such that the winds flow out of the southeast later in the morning; the NW to SE wind flow reversal occurs approximately at 11:00 at the Boulder monitor on February 21, 2008.

CalDESK Forward Trajectory Analyses for February 22, 2008 are shown in Figures S.7-38 through S.7-42.

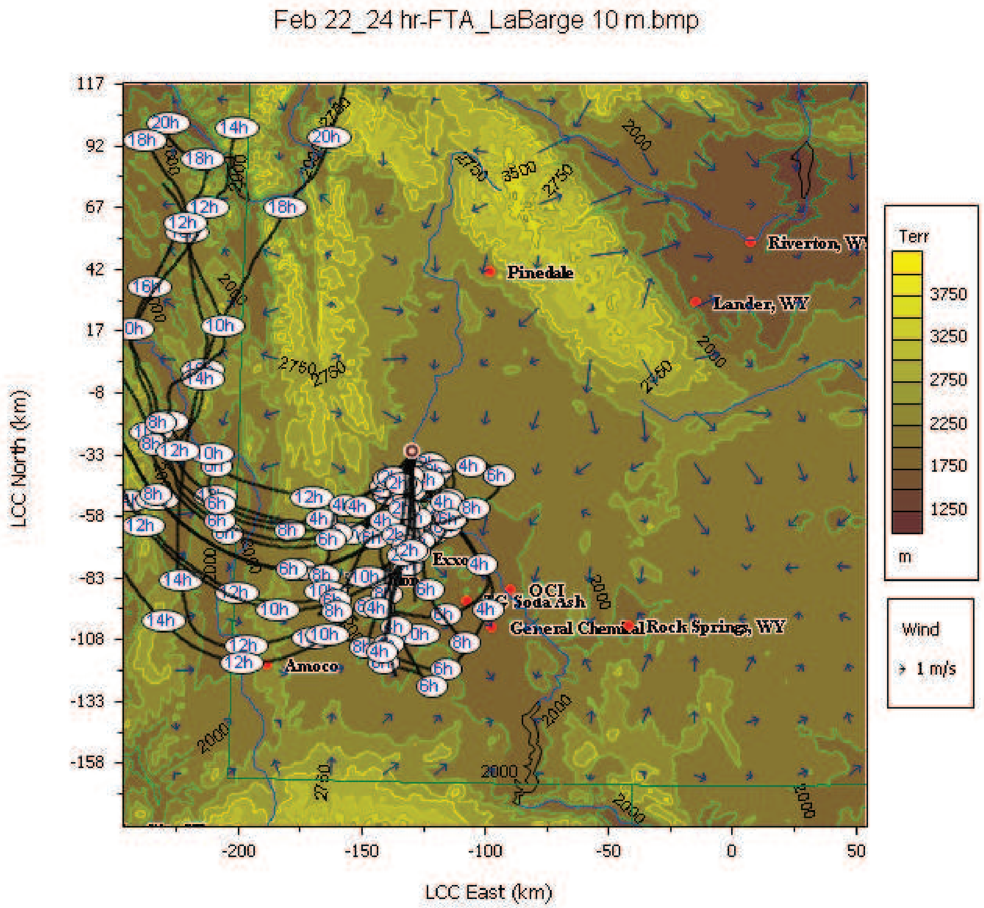


Figure S.7-38. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 22, 2008

The high pressure ridge continued to weaken during February 22, 2008, while a shortwave low pressure trough approached southwestern Wyoming from the northwest. Skies became mostly cloudy during the morning hours and light precipitation spread over the area later in the afternoon. However, the low level inversion stayed intact well into the afternoon, and ozone concentrations remained high during most of the day. No IOP operations were conducted this day because it was anticipated that the stable layer would be mixed-out by the trough by early morning and, therefore, trapped emission would be dispersed. Instead, the late arrival of the trough allowed one more day of high ozone concentrations.

As shown in Figure S.7-38, the trajectory analysis for the LaBarge area shows that most of the possible forward trajectory paths are now moving away from the UGRB during February 22nd. Figures S.7-38 through S.7-40 show air parcels tend to be blocked and channeled westward and then northward around the Wyoming Range, with limited air parcel movement into the UGRB. There are 1-2 trajectory paths showing air parcel movement from the Moxa Arch and Naughton areas into the UGRB, however, the vast majority of the air parcel trajectories do not enter the UGRB, due to the significant terrain blocking and channeling effects of the terrain that make up the Wyoming Range and the Wasatch Range. Terrain blocking and channeling effects can also be seen in Figure S.7-42 in the forward trajectories originating from the OCI Trona plant.

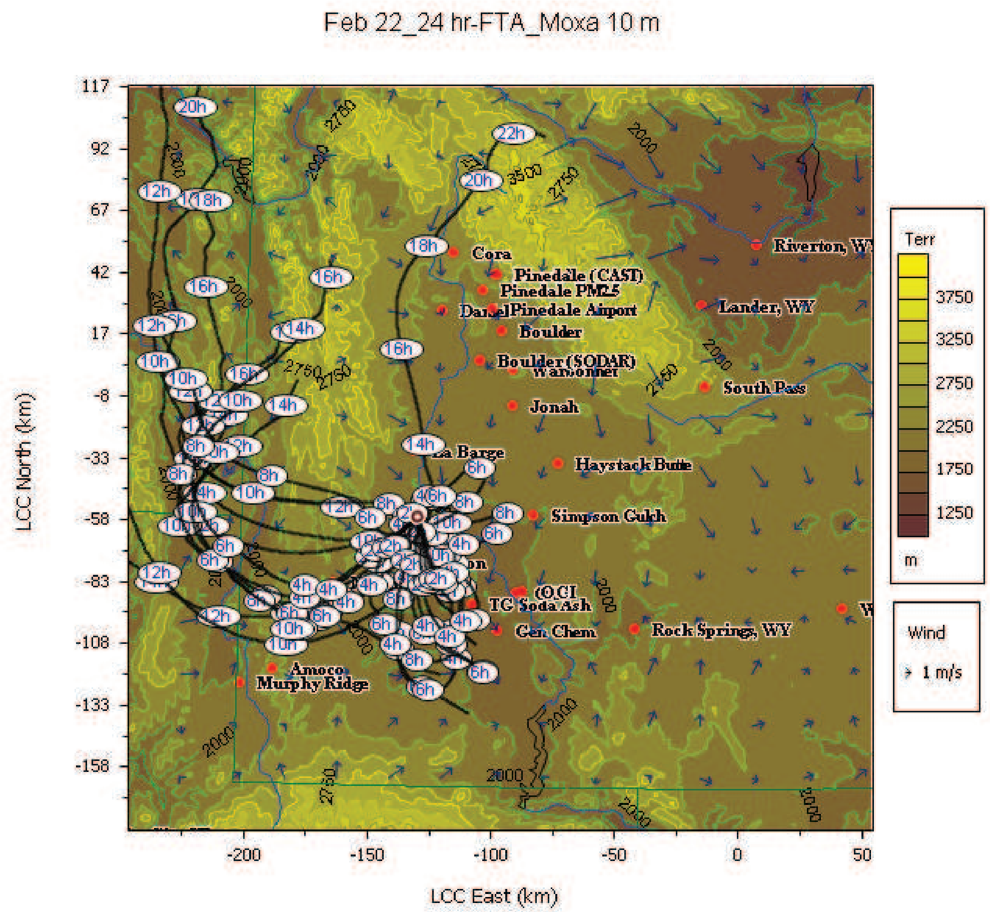


Figure S.7-39. 24-hour forward trajectory analysis in the Moxa Arch area on February 22, 2008.

Figure S.7-39 shows air parcels tend to be blocked and channeled westward and then northward around the Wyoming Range, with limited air parcel movement into the UGRB. There are 1-2 trajectory paths showing air parcel movement from the Moxa Arch into the UGRB, however, the vast majority of the air parcel trajectories do not enter the UGRB, due to the significant terrain blocking and channeling effects of the terrain that make up the Wyoming Range and the Wasatch Range.

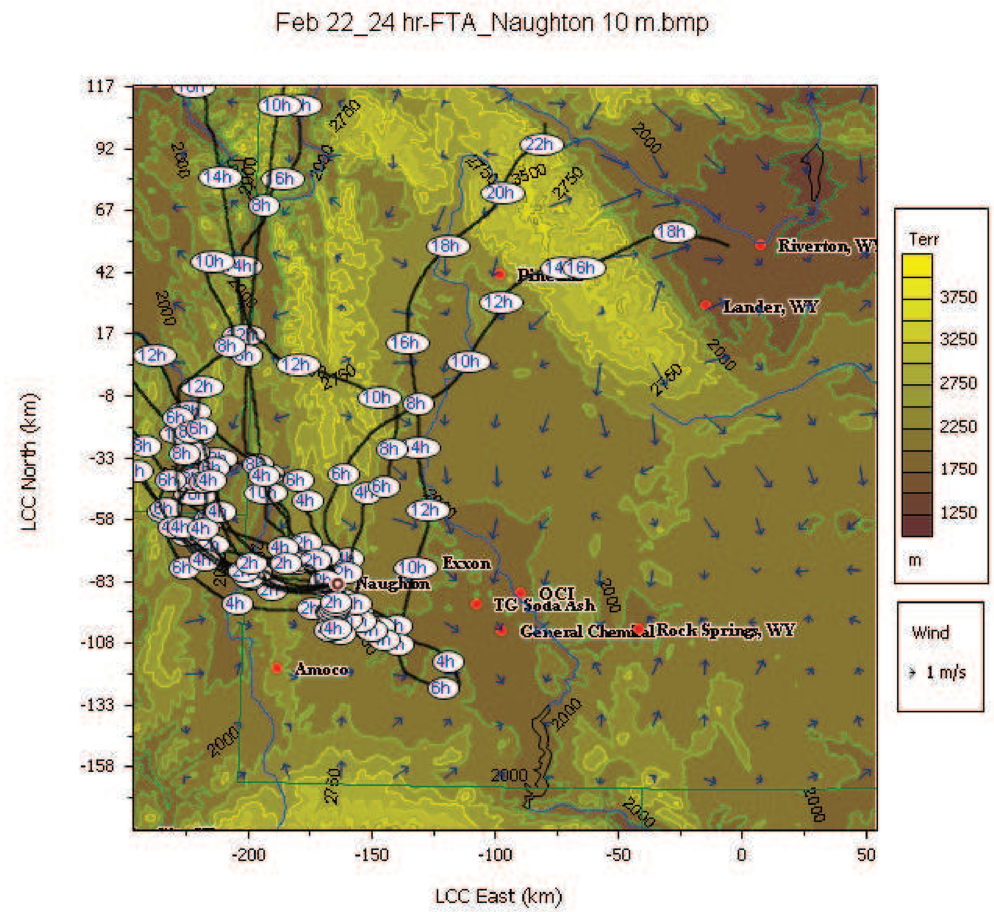


Figure S.7-40. 24-hour forward trajectory analysis at Naughton power plant on February 22, 2008.

There are two forward trajectory paths (2 am and 6 am) which show possible air parcel transport from the Naughton power plant into the UGRB. A 12-hour back trajectory analysis was performed at the Boulder monitor location (2 am – 2 pm) for February 22, 2008 to evaluate potential air parcel trajectories that could reach the Boulder monitor during this same time period (2 am and 6 am). The results of this back trajectory analysis are shown in Figure S.7-41.

Figure S.7-41 shows the calculated back trajectories of air parcels at the Boulder monitor tend to originate from within the UGRB, with very little air parcel movement occurring outside of the UGRB; the air parcels tend to stay within the UGRB during this 12 hour period (2 am – 2 pm) largely due to localized meteorological conditions in the UGRB. The back trajectory analysis in Figure S.7-41 shows a limited potential for sources outside the recommended nonattainment area to affect ozone measured at the Boulder monitor.

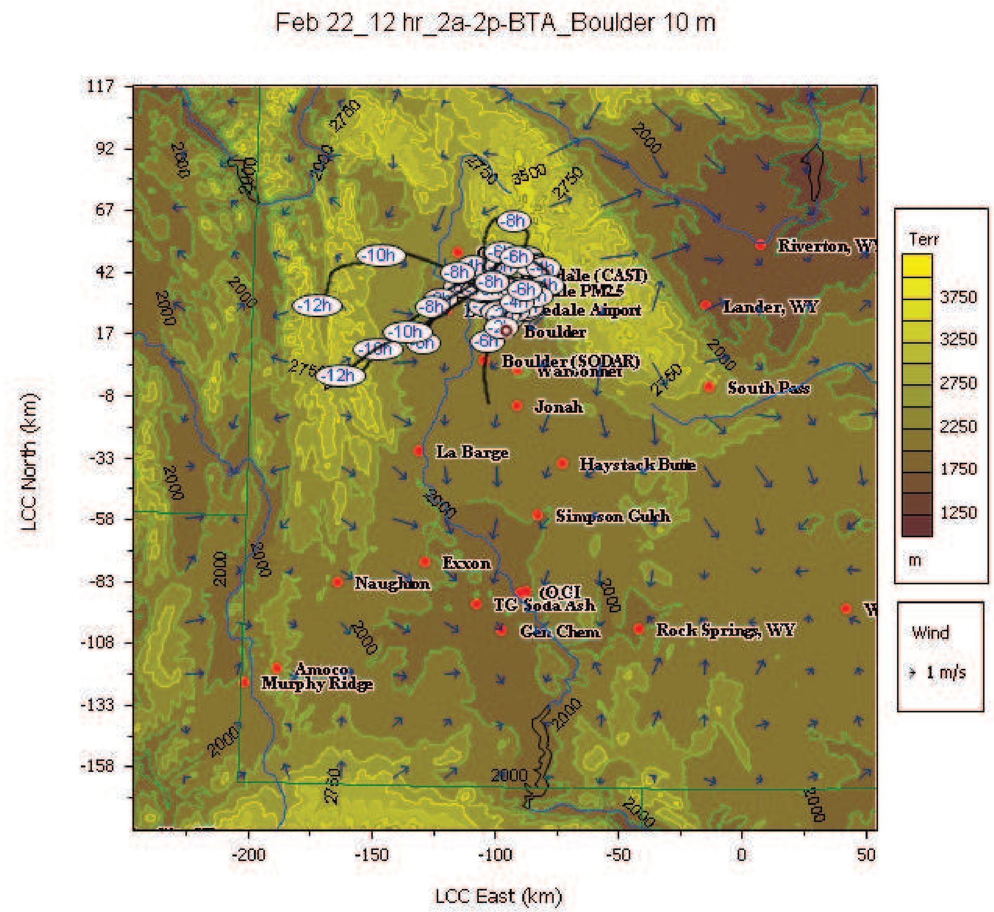


Figure S.7-41. 12-hour back trajectory analysis at Boulder monitor on February 22, 2008.

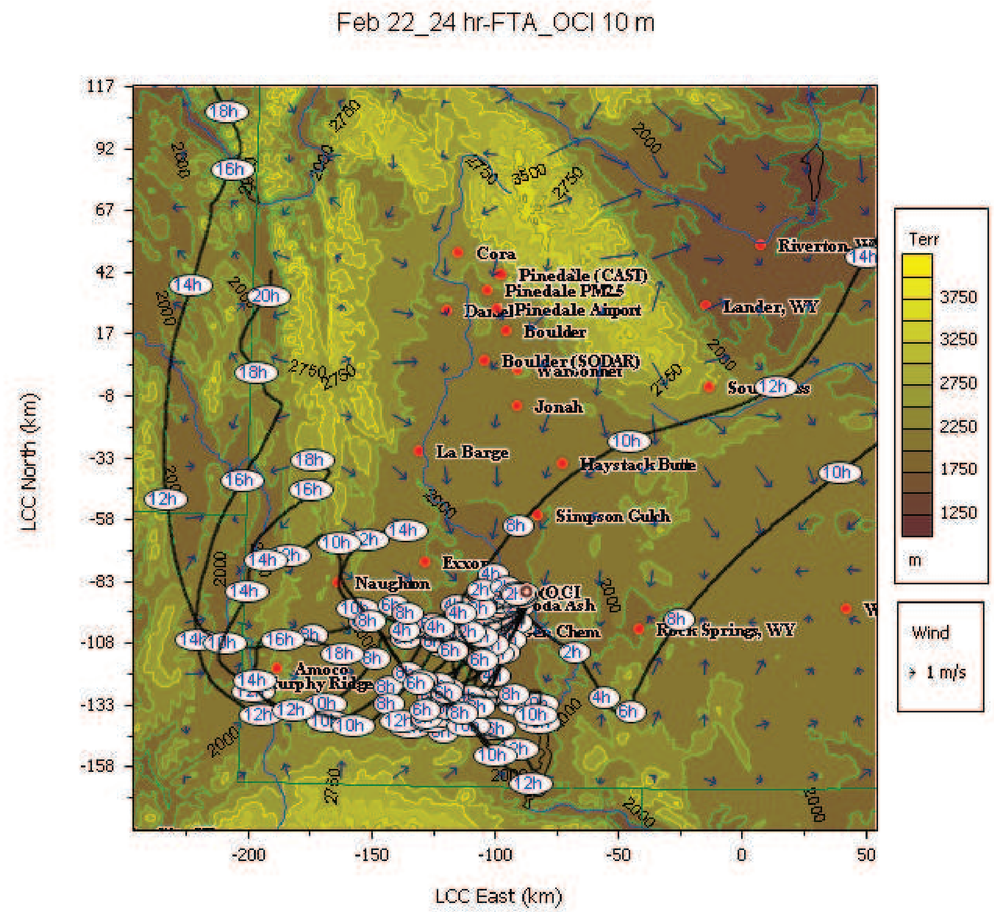


Figure S.7-42. 24-hour forward trajectory analysis at OCI Trona plant on February 22, 2008.

The predominant paths shown in the trajectory analysis shown in Figure S.7-42 trend to the south with northerly component to several of the modeled trajectories. Most of the possible forward trajectory paths are now moving away from the UGRB. Air parcels tend to be blocked and channeled westward and then northward around the Wyoming Range, with limited air parcel movement into the UGRB. There is one trajectory path showing air parcel movement from the OCI toward the UGRB. This trajectory generally parallels the southern boundary of the proposed nonattainment area along Pacific Creek. While some of the trajectory path may lie within the proposed nonattainment area, the path does not indicate that sources at OCI cause or contribute to elevated ozone levels within the proposed nonattainment area.

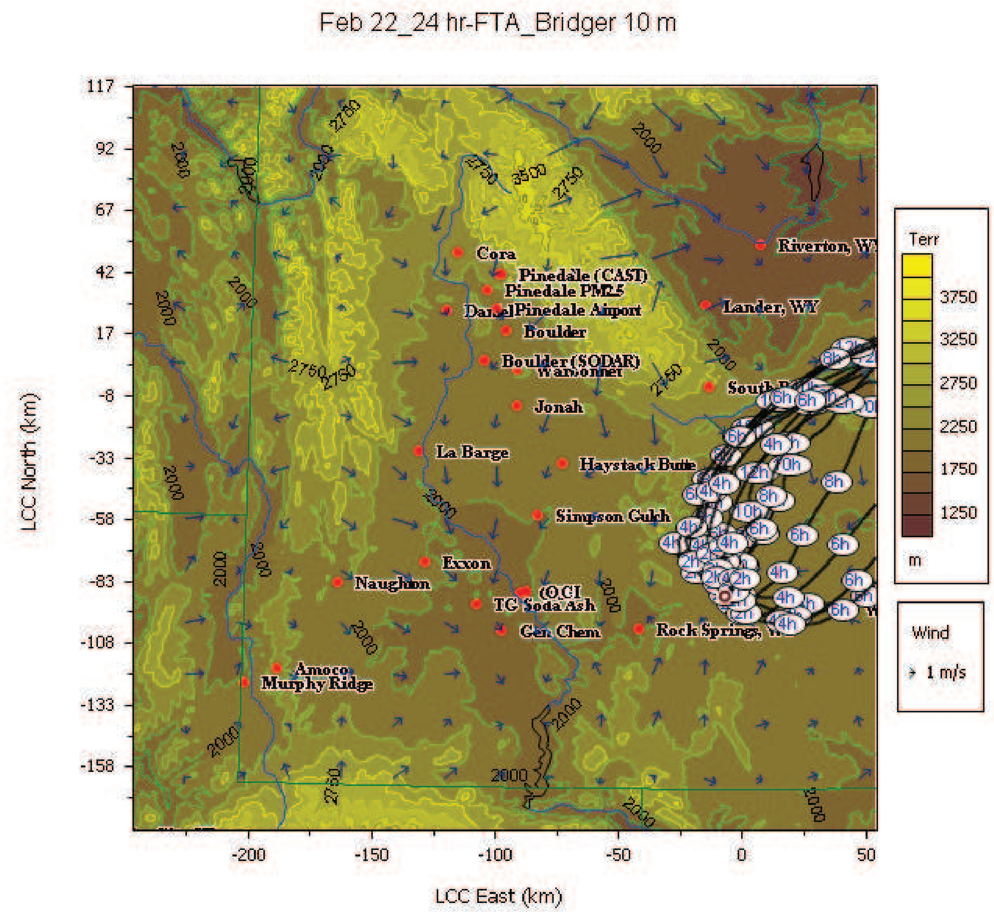


Figure S.7-43. 24-hour forward trajectory analysis at Bridger power plant on February 22, 2008.

The trajectory analysis in Figure S.7-43 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

CalDESK Forward Trajectory Analyses for February 23, 2008 are shown in Figures S.7-44 through S.7-48.

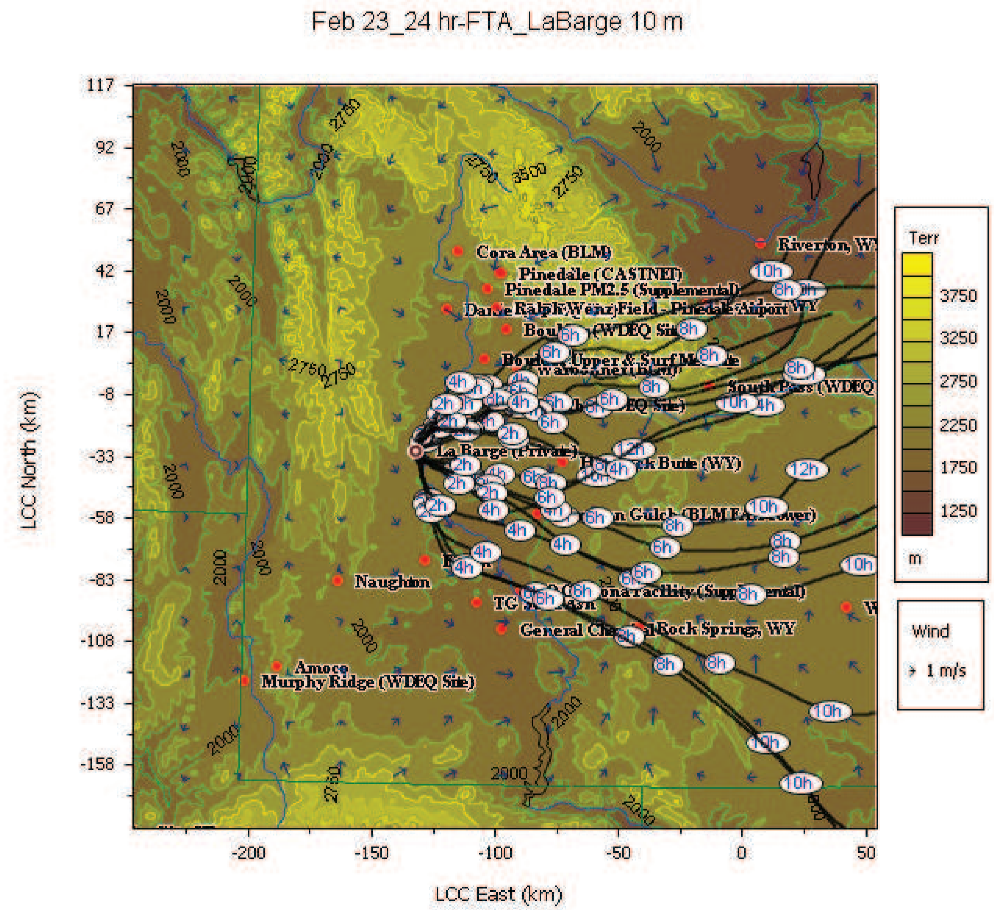


Figure S.7-44. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 23, 2008.

Figure S.7-44 shows the trajectory analysis for the LaBarge area; there are a few forward trajectory paths going northeast during Feb 23, 2008, but most are channeled around the rising terrain at the south end of the UGRB and the Wind River Range. As shown in Figures S.7-45 through S.7-48, the prevailing west and southwest winds generally move air parcels eastward and then northward, as reflected in the trajectory analysis for the Moxa Arch area, the Naughton power plant, the OCI Trona processing facility, and the Bridger power plant.

Feb 23_24 hr-FTA_Moxa_Middle 10 m

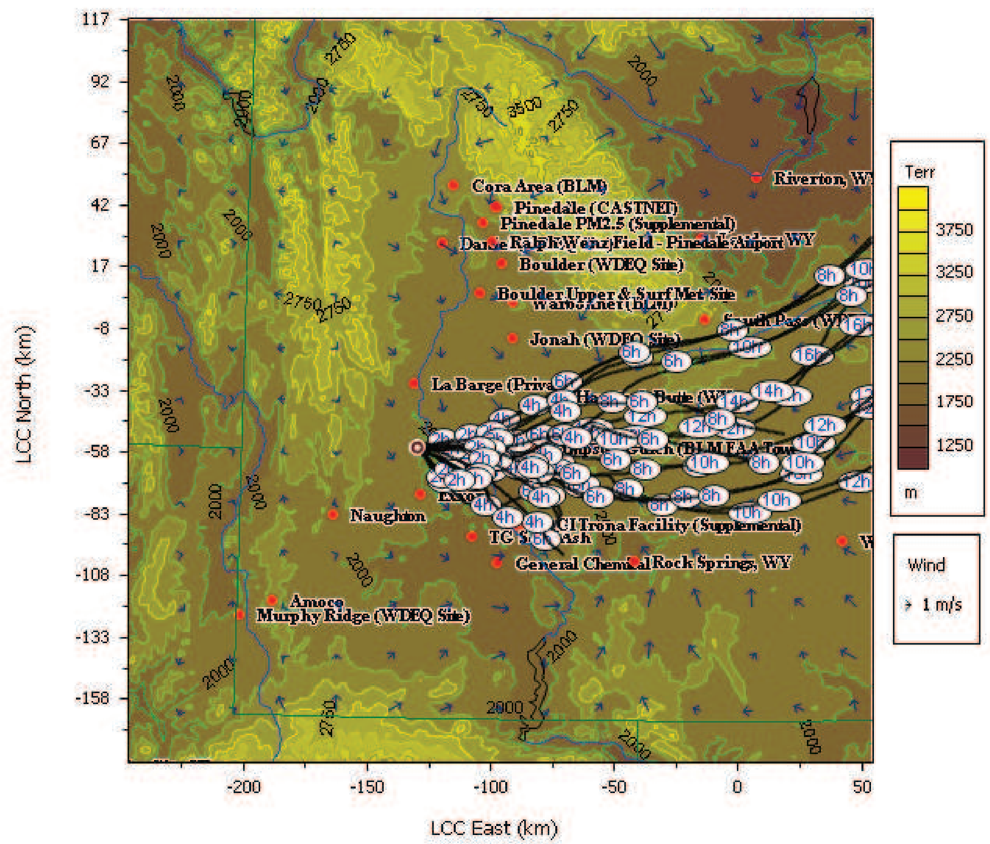


Figure S.7-45. 24-hour forward trajectory analysis in the Moxa Arch area on February 23, 2008.

The trajectory analysis shown in Figure S.7-45 places the initial air parcel release point in the northern part of the Moxa Arch field. The predominant paths shown trend to the east, and there is a slight northerly component to several of the modeled trajectories. These trajectories generally parallel the southern boundary of the proposed nonattainment area along Pacific Creek. While some of the trajectory paths lie within the proposed nonattainment area, none of the paths indicate that sources within the Moxa Arch cause or contribute to elevated ozone levels within the proposed nonattainment area.

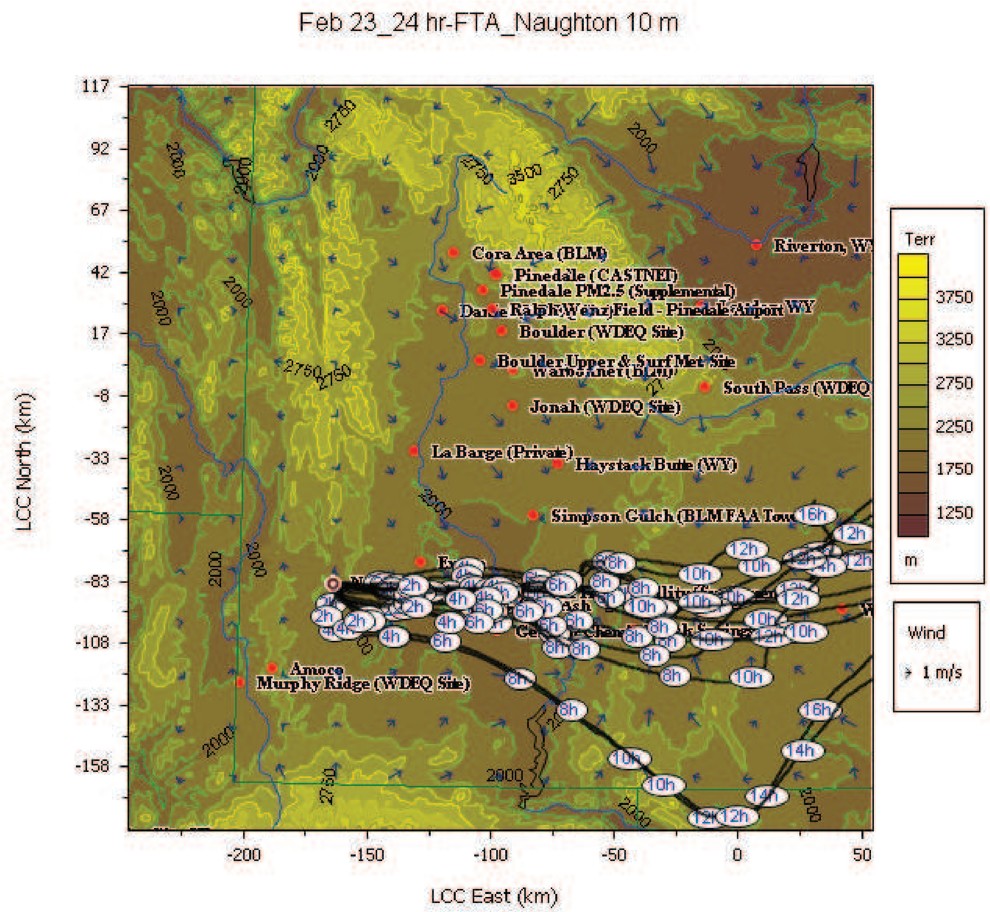


Figure S.7-46. 24-hour forward trajectory analysis at Naughton power plant on February 23, 2008.

The trajectory analysis in Figure S.7-46 shows all modeled trajectories from Naughton not entering the proposed nonattainment area.

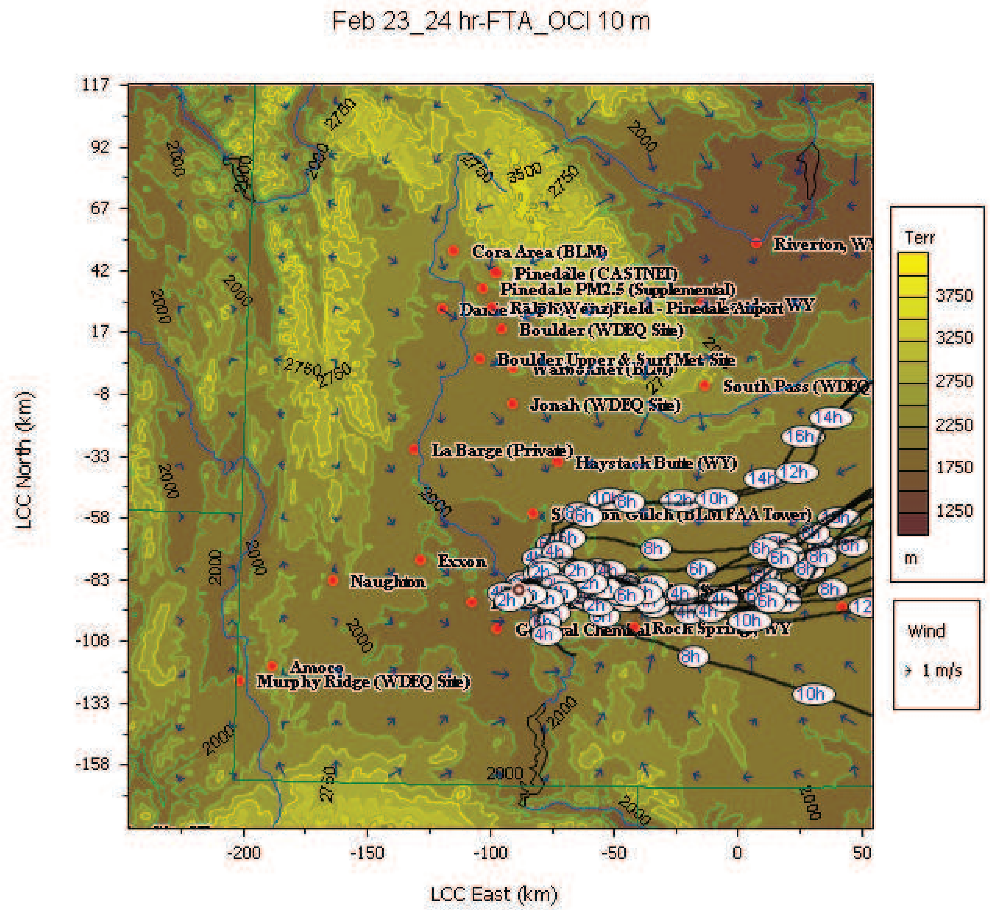


Figure S.7-47. 24-hour forward trajectory analysis at OCI Trona plant on February 23, 2008.

The trajectory analysis in Figure S.7-47 shows all modeled trajectories from OCI not entering the proposed nonattainment area.

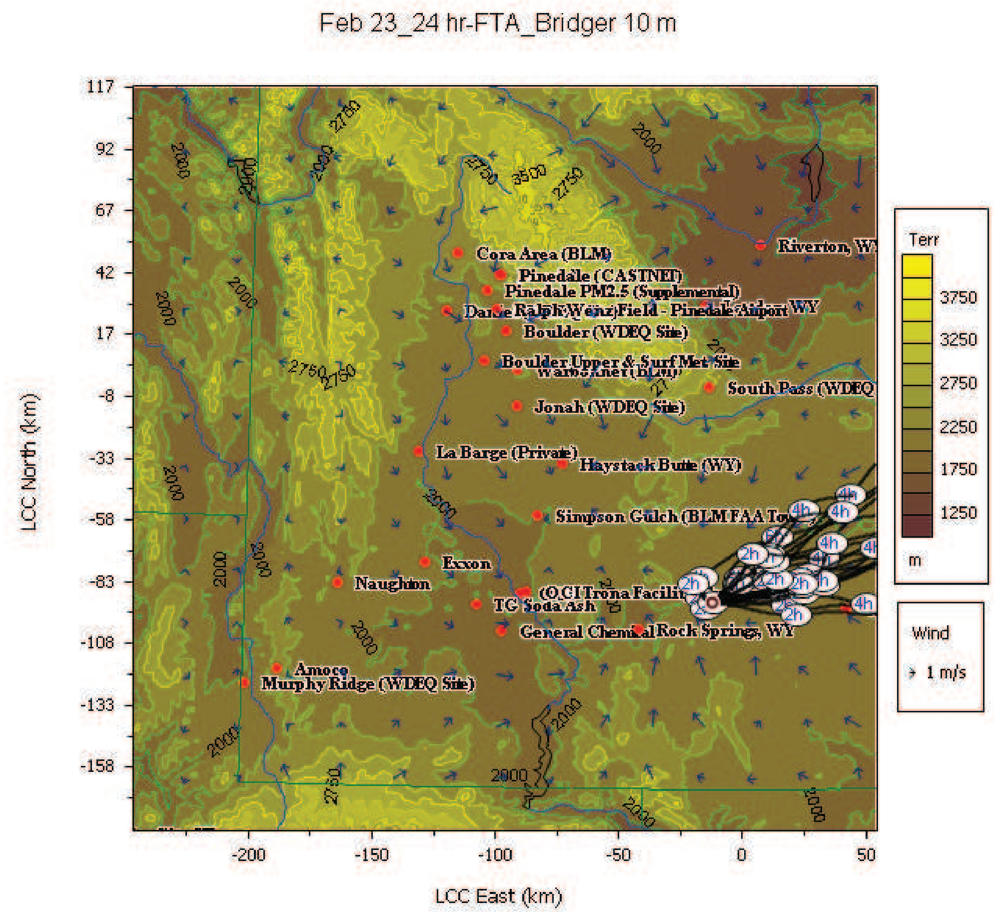


Figure S.7-48. 24-hour forward trajectory analysis at Bridger power plant on February 23, 2008.

The trajectory analysis in Figure S.7-48 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

<u>Summary of Trajectory Analyses</u>

The CalDESK trajectory analyses, based on a three dimensional wind field which incorporates the localized meteorological data collected during the 2008 field study have allowed AQD to evaluate air parcel movement as a means of evaluating precursor emissions and ozone transport into and out of the UGRB. These trajectories indicate that the southern boundary of the recommended nonattainment area defines an appropriate demarcation where emission sources within the nonattainment area may contribute ozone or ozone precursors to the Boulder monitor. Although the Fontenelle Creek, Little Sandy and Pacific drainages are not major topographic features, these drainage areas influence air movement into the UGRB from locations south of the recommended nonattainment area during the February 19-23, 2008 ozone episode and define a reasonable southern boundary for the nonattainment area. AQD has concluded that most, if not all, of the impact on the Boulder monitor just prior to and during these elevated ozone episodes is from emission sources located in the nonattainment area as described in this recommendation.

SECTION 8
JURISDICTIONAL BOUNDARIES

SYNOPSIS

The Sublette County jurisdictional boundary forms the northern and most of the western and eastern boundaries of the recommended nonattainment area. The remainder of the boundary is not jurisdictional but is based on topographical and meteorological considerations.

There is no existing local authority that transcends county boundaries, so the recommended nonattainment area has no single local administrative authority.

ANALYSIS

The Boulder monitor is located in Sublette County. Sublette County is governed by a three-person Commission. There are three incorporated towns in Sublette County: Pinedale, Big Piney and Marbleton. Approximately 80% of the land in Sublette County is owned by the government: BLM-40%; USFS-36%; State of Wyoming-4%. Federal and state land ownership in the surrounding counties follows a similar pattern.

The evaluation of the nonattainment area began with the Sublette County jurisdictional area as the presumptive boundary. This is consistent with EPA guidance in the December 4, 2008 memorandum which states: "Where a violating monitor is not located in a CBSA" (Core Based Statistical Area) "or CSA," (Combined Statistical Area) "we recommend that the boundary of the county containing the monitor serve as the presumptive boundary for the nonattainment area." The Boulder monitor is not in a CBSA or CSA.

The recommended nonattainment area includes all of Sublette County; the portion of Lincoln County northeast of the waterways of Aspen, Fontenelle, and Roney Creeks and northeast of Fontenelle Reservior and the Green River; and the portion of Sweetwater County northwest of the waterways of the Green River, the Big Sandy River, Little Sandy Creek, Pacific Creek, and Whitehorse Creek (see the detailed description in the introduction). This area includes the town of LaBarge in Lincoln County. The southern boundary of the recommended nonattainment area is defined based on topographical and meteorological considerations rather than jurisdictional boundaries. The Sublette County borders to the north, east, and west follow topographic features (mountain ranges) and are appropriate boundaries for the nonattainment area.

The six counties in Southwest Wyoming which were also included in the analysis are: Teton, Lincoln, Uinta, Sweetwater, and Fremont. Two Indian Tribal Nations are also located in the area, the Northern Arapahoe and Eastern Shoshone, at the Wind River Reservation in Fremont County. The reservation and the counties are shown in Figure S.1-1.

The recommended nonattainment area boundary does not fall under single authority, other than the State of Wyoming.

SECTION 9
LEVEL OF CONTROL OF EMISSION SOURCES

SYNOPSIS

Wyoming's NSR Program ensures that Best Available Control Technology (BACT) is utilized to reduce and eliminate air pollution emissions. Wyoming is fairly unique in that BACT is applied statewide to all new sources, both major sources and minor sources. Since 1995 all oil and gas production units that were constructed on or after May of 1974 require permits and BACT is utilized. In two of the gas fields in the proposed nonattainment area, more restrictive emission control requirements are already in effect. Wyoming has been focused on controlling emissions from oil and gas sources and has one of the most innovative and effective control programs in the nation.

While offset programs are traditionally limited to major source applications, the AQD issued an interim policy in August 2008 requiring offsets of ozone precursor emissions whenever a permit is issued for a new or modified source in Sublette County, regardless of major source applicability. This policy results in a net decrease in emissions of ozone precursors with every permit that is issued. This policy took effect after the ozone exceedances were recorded in the winter of 2008.

Data is not available for 2009, so it is too early to say with certainty whether this policy has contributed to reduced ozone concentrations at the Boulder monitor.

ANALYSIS

New Source Review Program

Wyoming's New Source Review (NSR) Program is a statewide permit program for the construction of new sources and modification of existing sources as established by Wyoming Air Quality Standards and Regulations (WAQSR) Chapter 6, Section 2, Permit requirements for construction, modification and operation and Chapter 6, Section 4, Prevention of significant deterioration. The primary purpose of the NSR Program is to assure compliance with ambient standards set to protect public health, assure that Best Available Control Technology is utilized to reduce and eliminate air pollution emissions, and to prevent deterioration of clean air areas. Any amount of air contaminant emissions from a facility subjects it to Wyoming's NSR Program.

Best Available Control Technology

Due to a desire to maintain and improve Wyoming's air quality, the Best Available Control Technology process is applied statewide to new sources, both major sources and minor sources, under the Wyoming NSR Program's permitting process. The BACT process is most appropriately defined as the elimination of pollutants from being emitted into the air whenever technically and economically feasible to do so. While the Air Quality Division takes the State and federally-required BACT review in the Prevention of Significant Deterioration (PSD) permitting actions seriously, AQD takes the State-required BACT review in minor source permitting actions equally as seriously, as the bulk of AQD's permit applications are for minor sources.

Control of Oil and Gas Production Sources

Within the recommended nonattainment area, the bulk of the NSR Program activity is due to oil and gas production and is permitted per the *Oil and Gas Production Facilities Chapter 6, Section 2, Permitting Guidance* discussed below. The remainder of the activity is attributed to facility types such as the compressor stations, asphalt plants and crushing and screening operations, which are permitted per Chapter 6, Section 2 and Chapter 6, Section 4 as described above.

In October 1995, AQD initiated a program to ensure that all oil and gas production units in southwest Wyoming, as well as the entire state, that were constructed since May of 1974 (the effective date of Wyoming's NSR Permit Program) were permitted and that BACT is utilized to control or eliminate emissions from both major and minor sources. To guide oil and gas producers through the NSR permitting process, AQD developed an oil and gas industry guidance document (Guidance) that was released in June of 1997. The Guidance has been revised several times since it was originally released in June of 1997. The most recent revision took effect in August of 2007 and includes requirements that apply statewide as well as specifically to the Jonah and Pinedale Anticline Development (JPAD) Area. The emphasis of the Guidance relies on a "Presumptive BACT" process, which results in more emissions being controlled earlier in the life of the production site. This is accomplished by allowing start up or modification of the production site to occur prior to obtaining a construction permit, provided the operators of such facilities meet certain emission control requirements, including timely installation of controls, which have been established through the Presumptive BACT process. Within the JPAD Area, emission control requirements are more restrictive and become effective upon start up or modification of the production site.

Under the WAQSR, applicants for permits are required to demonstrate to the Administrator of the Air Quality Division, that "[t]he proposed facility will not prevent the attainment or maintenance of any ambient air quality standard." [WAQSR Chapter 6, Section 2(c)(ii)] To allow applications for new or modified emission sources of VOC and/or NOx to be processed while the Division and industry initiatives are taken to reduce the overall emission levels for VOC and/or NOx in Sublette County, AQD adopted the *Interim Policy on Demonstration of Compliance with WAQSR Chapter 6, Section 2(c)(ii) for Sources in Sublette County* on July 21, 2008. The Interim Policy describes options that AQD will consider as an adequate WAQSR Chapter 6, Section 2(c)(ii) demonstration for permit applications (i.e., new as well as applications currently under AQD analysis) for new or modified emission sources in Sublette County.

Options for the Chapter 6, Section 2(c)(ii) demonstration include:

a. Ambient ozone modeling for any application requesting increases in VOCs and/or NOx emissions.

b. Emission reductions for VOCs and/or NOx emissions.

c. Applicants may propose alternate innovative demonstrations to the AQD.

To date, most applicants have chosen to offset VOC and/or NOx emissions and permit conditions have been established to make the commitments to control emissions federally enforceable.

During the implementation of the Interim Policy, other long-term approaches (e.g., development of a regional ozone model and implementation of additional control strategies) to deal with unacceptable ozone levels in the recommended nonattainment area, will continue to be pursued by AQD.

<u>Statewide and Industry-wide Control of Volatile Organic Compounds (VOC)</u>

WAQSR Chapter 13 establishes minimum requirements for motor vehicle emission control.

The following federal rules which are incorporated by reference in WAQSR Chapter 5 by reference contain performance or emission standards for VOCs that may apply to sources within the recommended nonattainment area and in adjacent areas:

40 CFR Part 60, Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971

40 CFR Part 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

40 CFR Part 60, Subpart Db - Standards of Performance for Industrial- Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart I - Standards of Performance for Hot Mix Asphalt Facilities

40 CFR Part 60, Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978

40 CFR Part 60, Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984

40 CFR Part 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines

40 CFR Part 60, Subpart WWW - Standards of Performance for Municipal Solid Waste Landfills

40 CFR Part 63, Subpart F - National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry

40 CFR Part 63, Subpart H - National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks

40 CFR Part 63, Subpart M - National Perchloroethylene Air Emission Standards for Dry Cleaning Facilities

40 CFR Part 63, Subpart R - National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

40 CFR Part 63, Subpart T - National Emission Standards for Halogenated Solvent Cleaning

40 CFR Part 63, Subpart HH - National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities

40 CFR Part 63, Subpart OO - National Emission Standards for Tanks - Level 1

40 CFR Part 63, Subpart PP - National Emission Standards for Containers

40 CFR Part 63, Subpart QQ - National Emission Standards for Surface Impoundments

40 CFR Part 63, Subpart RR - National Emission Standards for Individual Drain Systems

40 CFR Part 63, Subpart SS - National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process

40 CFR Part 63, Subpart TT - National Emission Standards for Equipment Leaks - Control Level 1

40 CFR Part 63, Subpart UU - National Emission Standards for Equipment Leaks - Control Level 2 Standards

40 CFR Part 63, Subpart VV - National Emission Standards for Oil-Water Separators and Organic-Water Separators

40 CFR Part 63, Subpart WW - National Emission Standards for Storage Vessels (Tanks) - Control Level 2

40 CFR Part 63, Subpart HHH - National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities

40 CFR Part 63, Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

40 CFR Part 63, Subpart VVV - National Emission Standards for Hazardous Air Pollutants: Publicly Owned Treatment Works

40 CFR Part 63, Subpart AAAA - National Emission Standards for Hazardous Air Pollutants: Municipal Solid Waste Landfills

40 CFR Part 63, Subpart EEEE - National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)

40 CFR Part 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

40 CFR Part 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

40 CFR Part 63, Subpart CCCCC - National Emission Standards for Hazardous Air Pollutants for Coke Ovens: Pushing, Quenching, and Battery Stacks

40 CFR Part 63, Subpart GGGGG - National Emission Standards for Hazardous Air Pollutants: Site Remediation

40 CFR Part 63, Subpart HHHHH - National Emission Standards for Hazardous Air Pollutants: Miscellaneous Coating Manufacturing

40 CFR Part 63, Subpart LLLLL - National Emission Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing Manufacturing

Statewide and Industry-wide Nitrogen Oxides (NOx)

WAQSR Chapter 2 establishes ambient air quality standards for those areas under WDEQ's jurisdiction. The standard for nitrogen oxides (NOx) is 100 ug/m^3 as an annual arithmetic mean. All facilities that are required to obtain a New Source Review (NSR) permit or a Title V permit under WAQSR Chapter 6 must demonstrate compliance with the State's ambient air quality standard before a permit can be issued.

WAQSR Chapter 3, Section 3 specifies nitrogen dioxide emission standards. Permitting rules require sources to meet NOx emission standards.

The following federal rules, which are incorporated by reference into Chapter 5, Sections 2 and 3 contain performance or emission standards for NOx that may apply to sources in the proposed nonattainment area and in the surrounding counties:

40 CFR Part 60, Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971

40 CFR Part 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

40 CFR Part 60, Subpart Db - Standards of performance for Industrial- Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines

The following federal New Source Performance Standards have not yet been adopted into State rules, but are scheduled for adoption. The federal standards will still apply.

NSPS Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

NSPS Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

NSPS Subpart KKKK - Standards of Performance for Stationary Combustion Turbines)

Contingency Plans

AQD requested that producers in parts of the proposed nonattainment area prepare emission reduction plans to be implemented when an ozone advisory is issued. The BLM adopted a contingency plan requirement in the Pinedale Anticline ROD. Producers, which cumulatively account for greater than 99% of production in the Pinedale Anticline, submitted contingency plans to the AQD. During the first quarter of 2009, the AQD issued ozone advisories on February 4th and 5th. The contingency plans were implemented and no 8-hour ozone values above 0.075 ppm were recorded at FRM monitors for those days.

CONCLUSIONS

The information presented in the preceding nine-factor analysis provides documentation and compelling evidence supporting a finding that the UGRB, as shown on the map in the Introduction, should be designated as nonattainment for the 2008 ozone NAAQS. It is important to note that only areas over which Wyoming has direct air quality jurisdiction are included in this nonattainment finding and recommendation. The Northern Arapahoe and Eastern Shoshone Indian Tribes are distinct nations or entities and consequently such Tribal lands (the Wind River Reservation) are specifically excluded from this designation recommendation.

The Wyoming AQD bases this recommendation on a careful review of the circumstances surrounding the incidence of elevated ozone events. Elevated ozone in the UGRB is associated with distinct meteorological conditions. These conditions have occurred in February and March in some (but not all) of the years since monitoring stations began operation in the UGRB in 2005. Our determination of an appropriate nonattainment area boundary is focused on an evaluation of EPA's recommended nine factors, applied to the first quarter of the year, during which winter ozone episodes occur. This timing does not change how the factors are reviewed, except for emissions inventory and meteorology. It is important to evaluate inventory and meteorology during the first quarter of the year in order to focus on the very specific conditions that lead to high ozone.

The most compelling reasons for the boundary recommendation are based on the meteorological conditions in place during and just prior to elevated ozone events. Elevated ozone episodes occurred in 2005, 2006 and 2008; they were associated with very light low-level winds, sunshine, and snow cover, in conjunction with a strong low-level surface-based temperature or "capping" inversion. The longest such event, which also resulted in the highest measured ozone of 122 ppb as an 8-hour average at the Boulder station, has been reviewed in detail and summarized in Section 7 of this document. Section 7 demonstrates that sources outside the recommended nonattainment area would not have a significant impact on the Boulder monitor due to the presence of the inversion and very low winds, which significantly limit emissions and ozone transport from sources located outside of the UGRB. Using detailed meteorological data collected during the February 19-23, 2008 ozone episode, a 1 kilometer high resolution (spatial and temporal) 3-dimensional gridded wind field was developed and used in trajectory analyses. The trajectory analyses show that air parcels originating at sources located south of the recommended nonattainment area – including power plants, Trona facilities, and the Moxa Arch gas field – are generally transported eastward and do not enter the UGRB just prior to and during the February 19-23, 2008 ozone episode. The meteorological conditions present during this multi-day ozone episode are representative of the meteorological conditions that were present during previous wintertime elevated ozone events that occurred in 2005 and 2006. From the trajectory analyses, it is concluded that emission sources located outside of the recommended nonattainment boundary could only have a very limited impact on the Boulder monitor, as the mountains to the west, north and east, along with the observed low wind speeds, would greatly limit the possibility of emissions transport.

The nine-factor analysis also concluded the following:

1. Ozone monitoring outside of the UGRB throughout Wyoming shows attainment of the 2008 NAAQS.
2. Emissions inventories of ozone precursors indicate that sources within the UGRB emit significant levels of precursors. Emissions from outside of the UGRB (while comparable to [for VOCs] or greater than [for NOx] emissions from within the UGRB) do not significantly influence the formation of ozone during and immediately preceding episodes of elevated ozone.
3. Population densities in Sublette and surrounding counties are very low and are not expected to be an important factor in ozone formation. This is also true of traffic and commuting patterns, which would be expected to be more important in urban areas rather than the rural communities and open spaces of southwest Wyoming.
4. The pace of growth in the oil and gas industry is significantly higher in the UGRB than in surrounding areas, which would correspond to a more rapid increase in emissions within the recommended nonattainment area in recent years.
5. Significant terrain features influence the meteorology throughout southwest Wyoming. Under a stagnating high pressure system, strong temperature inversions and low mixing heights tend to produce limited atmospheric mixing and precursor emissions can build up to high concentrations.

The elevated ozone episodes within the UGRB represent a unique situation which is quite different from other ozone nonattainment areas. The UGRB is rural with a very low population density; the only significant industry present is oil and gas. The significant terrain features surrounding the UGRB and the very low wind speeds associated with elevated ozone episodes may limit the ability of trajectory models, such as the HYSPLIT model, to accurately represent movement of air parcels within, into and out of the UGRB during these winter ozone events.

Due to the importance of meteorology to the formation of elevated ozone at the Boulder monitor – that is, ozone at levels that result in an exceedance of the NAAQS occurs during periods characterized by low mixing heights, temperature inversions and sustained low wind speeds – any emission reduction applied to sources outside of the UGRB will not result in any meaningful change in ozone levels at the Boulder monitor during these episodic conditions.

The information presented in this technical support document provides a strong weight-of-evidence basis for the recommended nonattainment boundary.

Appendix S.1.
Final Report 2008 Upper Green River Winter Ozone Study

http://deq.state.wy.us/aqd/Monitoring%20Data.asp

Appendix S.3
Population Density by Census Tract

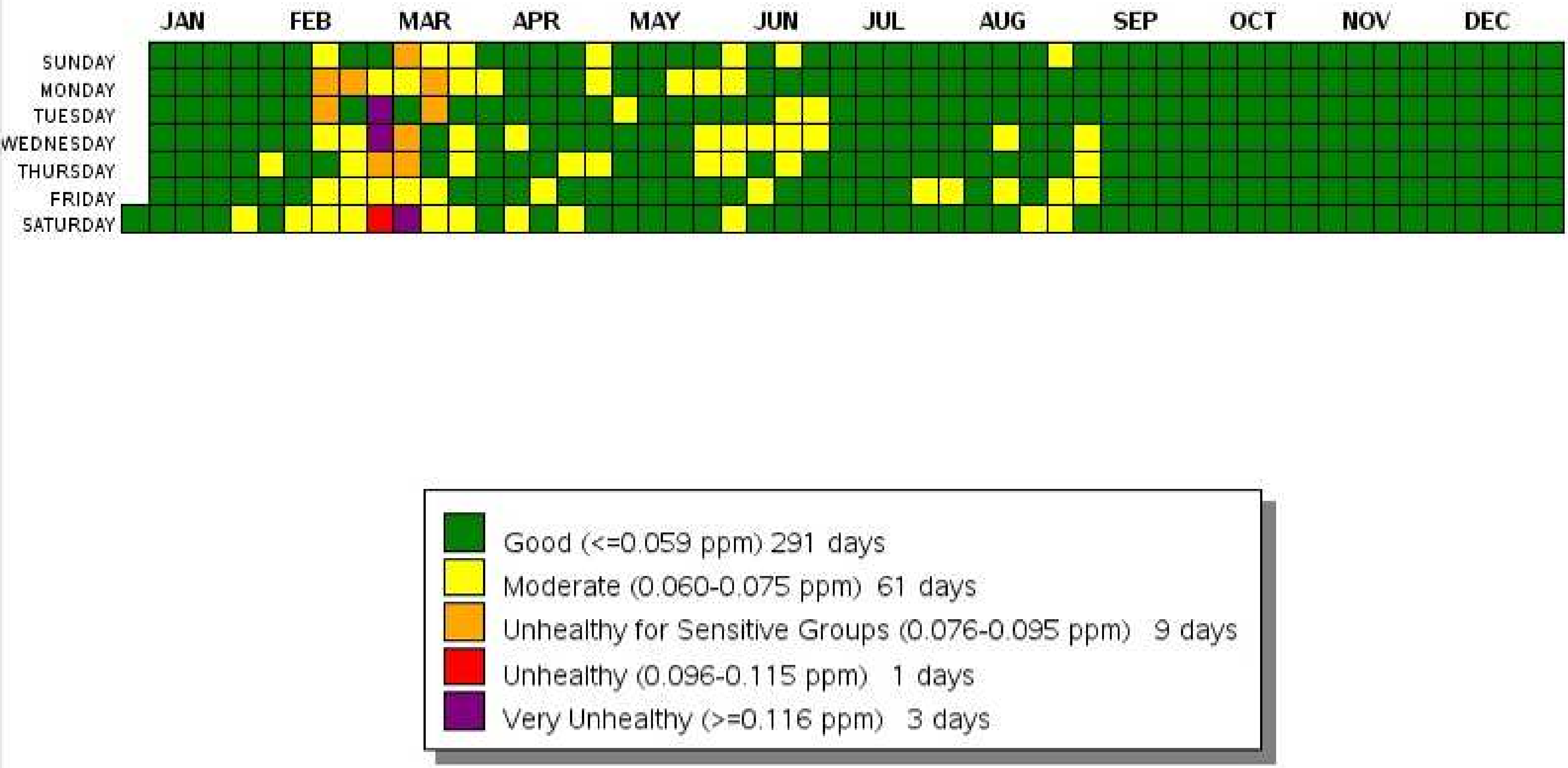
Appendix S.4.A.
2007 Vehicle Miles on State Highways By County

Appendix S.4.B.
Commuting Patterns in Sublette County

Appendix.
Glossary

Daily Ozone AQI Levels in 2011

Sublette County, WY



Source: EPA's Air Explorer (http://www.epa.gov/airexplorer/)
Generated on: 06NOV12

Report: U.S. coal power plants emit toxic air pollutants

EPA: Energy Star TVs must use 40% less energy

Mar 09, 2011

Wyoming's smog exceeds Los Angeles' due to gas drilling

By Wendy Koch, USA TODAY

Updated 2011-03-09 11:52 AM

CAPTION By Mead Gruver, AP

Rural Wyoming, known for breathtaking vistas, now has worse smog than Los Angeles because of its boom in natural gas drilling.

Residents who live near the gas fields in the state's western corner are complaining of watery eyes, shortness of breath and bloody noses, reports the Associated Press. The cause is clearer than the air: local ozone levels recently exceeded the highest levels recorded in the biggest U.S. cities last year.

Preliminary data show the region's ozone levels last Wednesday got as high as 124 parts per billion, which is two-thirds higher than the Environmental Protection Agency's maximum healthy limit of 75 parts per billion and above the worst day in Los Angeles all last year, 114 parts per billion, AP reports. On March 1, the ozone levels hit 116 parts per billion.

Last year, too, Wyoming's gas-drilling area had days when its ozone levels exceeded Los Angeles' worst for 2009.

Yet, the Cowboy State is prospering. It has one of the nation's lowest unemployment rates, 6.4 percent, and is expected to run a budget surplus this year.

About Wendy Koch

Wendy Koch has been a reporter and editor at USA TODAY since 1998, covering politics and social issues. She's begun a quest to build the most eco-friendly home her budget allows. She'll share her experience and give you tips for greening your home. More about Wendy

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- Home by Sunset
- Inhabitat
- Jetson Green
- Mother Earth News

"They're trading off health for profit. It's outrageous. We're not a Third World country," said Elaine Crumpley, a retired science teacher who lives just outside Pinedale, Wyo., told the AP.

In the Upper Green River Basin, at least one daycare center called off outdoor recess, and state officials urged the elderly, children and people with respiratory conditions to avoid strenuous or extended outdoor activity.

Gas industry officials say they're trying to curb smog by reducing truck traffic and switching to drilling rigs with pollution control equipment, and they report fewer emissions contributing to smog than in 2008, reports the AP. On Monday, Gov. Matt Mead discussed with state regulators and industry representatives what else companies can do.

See photos of: Los Angeles, Wyoming

TAGS: LOS ANGELES WYOMING ENVIRONMENTAL PROTECTION AGENCY PINEDALE OZONE SMOG COWBOY STATE UPPER GREEN RIVER BASIN

PREVIOUS
Report: U.S. coal power plants emit toxic air pollutants

NEXT
EPA: Energy Star TVs must use 40% less energy

pencil-pusher Score: -3
10:05 AM on March 9, 2011
Everybody in Wyoming should get an aerosol spray can and empty it in a day. Ozone will be depleted. Problem solved!

smithy46
10:05 AM on March 9, 2011
Score: -8
If the poeple of Wyoming don't grin and bear it then they are America-hating, terrorist-loving, communist sympathizers!! If they're real Americans they'll take a hit for the team.
Report Abuse

mindstorms
10:07 AM on March 9, 2011
Score: 2
Man polluting the environment they live in....I'm shocked?
Report Abuse

John Spencer
10:08 AM on March 9, 2011
Score: 0
Now there's an idea pencil-pusher.
Report Abuse

rawn
10:09 AM on March 9, 2011
Score: 0
Typical red state filled with oil and smog. Texas must be jealous.
Report Abuse

False_Paradigm
10:10 AM on March 9, 2011
Score: 1
DRILL BABY DRILL!!! DERP AH-DERPITY DOO!!!
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foolsarerequired
10:11 AM on March 9, 2011
Score: 6
The gas and oil executives wouldn't have a house no where near this drilling.
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Man the Middle
10:13 AM on March 9, 2011
Score: 0
...and the smell is overwhelming!!!
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Independent01
10:15 AM on March 9, 2011
Score: -1
Oh well just send us your gas.
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Next

WYVisNet website. Graphic by Pinedale Online.">

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Pinedale Online > News > March 2011 > Ozone Advisory for Friday March 18, 2011 > Ozone Calendar

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© Photo by Pinedale Online

Ozone Calendar

Wyoming DEQ has issued 10 Ozone Advisories for the Upper Green River Basin since February 28, 2011. Actual ozone levels may or may not have exceeded standards on any of those days. DEQ only issues prediction advisories, which are made based on weather predictions the day before they believe conditions may be condusive to creating high ozone levels in a given area. They do not issue a notice or advisory in real time to the public or media when high ozone levels are actually occuring. To see monitor readings in real time, visit the DEQ WYVisNet website. Graphic by Pinedale Online.

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Pinedale Online > News > February 2011 > Ozone Advisory for Monday, Feb. 28

Ozone Advisory for Monday, Feb. 28

by Wyoming Department of Environmental Quality
February 27, 2011

Upper Green River Basin, Wyo. - The Air Quality Division (AQD) of Wyoming's Department of Environmental Quality (DEQ), in conjunction with the Wyoming Department of Health (WDH), is issuing an ozone advisory for tomorrow, Monday February 28, 2011, for the Upper Green River Basin, in Sublette County.

The DEQ-AQD would like to communicate that this particular Ozone Advisory is anticipated to be a multi-day event. Weather forecasting for conditions conducive to elevated 8-hour ozone will continue on a daily basis and the AQD will continue to issue updated advisory status by noon each day such that, if the weather forecast changes, advisory status may also change. The DEQ-AQD will also be conducting intensive sampling of ozone and precursors during this period. These intensive measurements will focus on the vertical distributions of pollutants which will be accomplished by equipment attached to weather balloons.

Ozone is an air pollutant that can cause respiratory health effects especially to children, the elderly and people with existing respiratory conditions. People in these sensitive groups should limit strenuous or extended outdoor activities, especially in the afternoon and evening. More information on ozone and the health effects of ozone are available at the Wyoming Department of Health website, .http://www.health.wyo.gov.

An ozone advisory is issued when weather conditions appear to be favorable for the formation of ozone. Ozone appears to be elevated in the Basin when there is a presence of ozone-forming precursor emissions including oxides of nitrogen and volatile organic compounds coupled with strong temperature inversions, low winds, snow cover, and bright sunlight.

Current information on ozone levels at the Air Quality Division's monitoring stations at Daniel, Pinedale, Boulder, Juel Spring and the Wyoming Range can be found at www.wyvisnet.com.

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The New York Times

October 1, 2010

Air Quality Concerns May Dictate Uintah Basin's Natural Gas Drilling Future

By SCOTT STREATER of

An energy company's plan to drill more than 1,400 natural gas wells in northeast Utah's Uintah Basin could be tripped up by an emerging air pollution problem that has affected other densely developed oil and gas fields across the Rocky Mountain West.

The concern is wintertime ozone, a problem that federal regulators discovered for the first time in the basin just this year. If the phenomenon cannot be controlled, it could force Denver-based Gasco Energy Inc. to scale back plans to drill across 206,826 acres of mostly Bureau of Land Management property.

Ground-level ozone pollution, which is linked to respiratory diseases like asthma, is a well-known summer pollution problem, stemming from the mixing of auto and industrial emissions in sunlight and heat.

But federal regulators have discovered an unusual winter weather pattern in the Uintah Basin that causes ozone concentrations to reach potentially dangerous levels in January, February and March. The pattern is marked by stagnant air that allows emissions to collect in the lower atmosphere and then be converted into ozone by sunlight and heat reflecting off snow on the ground, said Stephanie Howard, a BLM environmental coordinator and the agency's project manager for the Gasco proposal.

Air pollution monitors recently installed in the Uintah Basin measured ozone concentrations exceeding federal health standards more than 68 times in the first three months of 2010, according to U.S. EPA data. On one day in January and two days in February, recorded ozone levels were nearly twice the federal health standard of 75 parts per billion.

“We think these ozone issues in the Uintah Basin call into question the justifica moving ahead to analyze or approve these sorts of projects,” said Steve Bloch, director of the Southern Utah Wilderness Alliance.

The winter ozone phenomenon surprised BLM, which this week issued a draft

impact statement (EIS) identifying hundreds of existing oil and gas wells in the basin as the primary cause of the ozone pollution.

The draft EIS is scheduled to be published tomorrow in the *Federal Register*, kicking off a 45-day public comment period through Nov. 15.

Gasco's project could still be permitted, though, since federal regulations require three consecutive years of monitoring data before a region can be deemed a violator of federal pollution standards, also known as National Ambient Air Quality Standards.

If the area were declared an ozone violator, EPA would mandate an emissions reduction plan to improve air quality by a certain deadline.

But BLM is not waiting for such a violation to occur. Rather, the agency's EIS includes measures to ensure the Gasco project does not exacerbate wintertime ozone, including possibly reducing or prohibiting drilling activity during the winter months.

"We're very anxious to see what the numbers are in January, February and March," Howard said. "We're holding our breath to see what happens."

Tougher standards

Further complicating the Gasco proposal is EPA's expected tightening of the ozone health standard by the end of the year.

EPA has proposed revising its "primary" health standard for ozone so that a region would violate the Clean Air Act if ozone concentrations reached between 60 and 70 parts per billion averaged over an eight-hour period. The agency has also proposed a "secondary" ozone standard aimed at protecting vegetation and sensitive ecosystems, including parks, wildlife refuges and wilderness areas (*Greenwire*, Jan. 7).

While a tougher ozone health standard would have its most immediate effect in urban areas, where motor vehicles contribute billions of tons of ozone-forming pollutants annually, the odorless gas has become a growing problem in remote areas as well, especially where oil and gas producers have sunk thousands of wells into the ground, resulting in releases of ozone precursors nitrogen oxide (NOx) and volatile organic compounds (VOCs).

The stakes could be especially high in Utah, one of the nation's fastest-growing states and a growing hub for oil and gas development, particularly within the Uintah Basin.

In fact, the Gasco Energy project is the smallest of four Uintah Basin drilling proposals currently under review by BLM. Collectively, these four projects could result in the drilling of more than 17,000 new natural gas wells across hundreds of thousands of acres of federal land over the next three years.

The largest is the Greater Chapita Wells Natural Gas Infill Project, which would place up to 7,028 wells across more than 40,000 acres of mostly BLM land. Next is the Greater Monument Butte plan, proposed by the Newfield Exploration Co. It calls for drilling 5,750 wells across 119,850 acres of mostly federal land. And finally, the Greater Natural Buttes Project, proposed by Kerr-McGee Oil & Gas Onshore LP, could result in drilling as many as 3,675 wells on 162,911 acres.

While drilling in the Uintah Basin has been going on in some form since the early 1900s, with some active federal leases dating back to the 1950s, Howard said better technologies and drilling techniques have attracted companies looking to access gas reserves at much greater depths than before.

"That's across the West. We are now able to develop more American oil and gas reserves that five, 10 years ago we didn't know how to," said Kathleen Sgamma, director of government affairs for the Denver-based Western Energy Alliance, an industry trade group.

Industry doubts readings

Sgamma, however, questioned the accuracy of the ozone readings in the Uintah Basin, saying the two monitors that registered high wintertime ozone were "faulty," and the readings did not pass EPA's quality assurance standards.

"That data cannot be used in determining the attainment status" of the region, Sgamma said.

Howard, however, disputed the assertion that the numbers were faulty, saying they had been vetted by EPA and posted on its website.

"I'm pretty sure that if the readings were faulty the EPA would not have published them," she said. "My understanding is those numbers are correct."

Faulty or not, Sgamma said the readings provide enough incentive for regulators and the industry to work together to ensure that emissions of ozone precursors stay low.

She also stressed that Uintah County, where the project would be located, currently is in compliance with federal health standards for ozone.

"Environmental groups are certainly trying to use the faulty readings in the basin as a means to stop oil and gas development and the associated jobs," Sgamma said. "But the bottom line is that economic activity does not need to be stopped in an area that remains in compliance for ozone."

Lessons from Wyoming

But the Uintah Basin is not the only place where oil and natural gas drilling activity is associated with high wintertime ozone.

In Sublette County, Wyo., wintertime ozone attributed largely to oil and gas production in the Jonah Infill and Pinedale Anticline gas fields could lead to Wyoming's first violations of EPA air quality standards, according to state officials. Federal maps also indicate that counties in the natural gas-rich Powder River Basin in northeast Wyoming could also violate federal air quality standards if EPA toughens its ozone health standard.

Wyoming Gov. Dave Freudenthal (D) asked EPA last year to designate Sublette County and portions of two other neighboring counties in the state's southwest corner as violating current ozone health standards (*Land Letter*, March 19, 2009). Wells in those two fields produced 7.6 million barrels of oil and 1.1 billion cubic feet of natural gas in 2008, according to state statistics.

Between 2000 and 2008, the number of annual new oil, gas and coalbed methane drilling wells in the region increased almost threefold, from 350 a year in 2000 to 925 a year in 2008, according to state figures. More than 2,600 new wells were drilled in Sublette County alone during that time.

An ozone monitor in southwest Wyoming began recording high ozone levels in 2005, and a technical analysis of air quality in the region conducted last year by the Wyoming Division of Air Quality found that 94 percent of VOCs and 60 percent of NOx emissions "are attributable to oil and gas production and development."

But last winter the region's ozone levels did not exceed federal ozone standards, in part because low wellhead prices significantly slowed production.

Industry officials attribute the drop in emissions to efforts by drillers to reduce emissions by up to 80 percent in the Pinedale Anticline region. Those measures include using cleaner-burning engines in machinery and piping oil and gas to reduce truck traffic in the field.

Meanwhile, BLM will continue to study wintertime ozone levels in Uintah Basin. Howard said the agency would likely allow Gasco to drill some wells before they have collected the three years of data needed to verify that the basin has an ozone problem.

Jeremy Nichols, climate and energy program director for WildEarth Guardians, said that would be a big mistake.

"BLM needs to understand they have a responsibility here, and they do need to start limiting operations and development activity when it looks like emission levels are going to rise," Nichols said. "The only way is to limit operations and limit development. They are going to have to stop rubberstamping all of these projects that are put in front of them."

Click here to read the draft EIS.

Streater writes from Colorado Springs, Colo.

For more news on energy and the environment, visit www.greenwire.com.
Greenwire is published by Environment & Energy Publishing. Read More »

Exhibit 45

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

49-047-200	1	2/21/2011	0.068	ppm	77	20	83	44201
49-047-200	1	2/23/2011	0.09	ppm	137	24	100	44201
49-047-200	1	2/24/2011	0.11	ppm	187	24	100	44201
49-047-200	1	2/25/2011	0.082	ppm	116	24	100	44201
49-047-200	1	2/26/2011	0.054	ppm	46	24	100	44201
49-047-200	1	2/27/2011	0.06	ppm	51	22	92	44201
49-047-200	1	2/28/2011	0.07	ppm	84	20	83	44201
49-047-200	1	3/1/2011	0.076	ppm	101	24	100	44201
49-047-200	1	3/2/2011	0.092	ppm	142	24	100	44201
49-047-200	1	3/3/2011	0.093	ppm	145	24	100	44201
49-047-200	1	3/4/2011	0.062	ppm	58	24	100	44201
49-047-200	1	3/5/2011	0.066	ppm	71	24	100	44201
49-047-200	1	3/6/2011	0.06	ppm	51	22	92	44201
49-047-200	1	3/7/2011	0.052	ppm	44	20	83	44201
49-047-200	1	3/8/2011	0.051	ppm	43	24	100	44201
49-047-200	1	3/9/2011	0.052	ppm	44	24	100	44201
49-047-200	1	3/10/2011	0.057	ppm	48	24	100	44201
49-047-200	1	3/11/2011	0.055	ppm	47	24	100	44201
49-047-200	1	3/12/2011	0.05	ppm	42	24	100	44201
49-047-200	1	3/13/2011	0.053	ppm	45	22	92	44201
49-047-200	1	3/14/2011	0.047	ppm	40	20	83	44201
49-047-200	1	3/15/2011	0.052	ppm	44	24	100	44201
49-047-200	1	3/16/2011	0.047	ppm	40	24	100	44201
49-047-200	1	3/17/2011	0.049	ppm	42	24	100	44201
49-047-200	1	3/18/2011	0.053	ppm	45	24	100	44201
49-047-200	1	3/19/2011	0.056	ppm	47	24	100	44201
49-047-200	1	3/20/2011	0.052	ppm	44	22	92	44201
49-047-200	1	3/21/2011	0.051	ppm	43	20	83	44201
49-047-200	1	3/22/2011	0.048	ppm	41	24	100	44201
49-047-200	1	3/23/2011	0.054	ppm	46	18	75	44201
49-047-200	1	3/24/2011	0.055	ppm	47	24	100	44201
49-047-200	1	3/25/2011	0.048	ppm	41	24	100	44201
49-047-200	1	3/26/2011	0.051	ppm	43	24	100	44201
49-047-200	1	3/27/2011	0.055	ppm	47	22	92	44201
49-047-200	1	3/28/2011	0.052	ppm	44	20	83	44201
49-047-200	1	3/29/2011	0.048	ppm	41	24	100	44201
49-047-200	1	3/30/2011	0.041	ppm	35	24	100	44201
49-047-200	1	3/31/2011	0.048	ppm	41	20	83	44201
49-047-200	1	4/1/2011	0.053	ppm	45	24	100	44201
49-047-200	1	4/2/2011	0.045	ppm	38	24	100	44201
49-047-200	1	4/3/2011	0.055	ppm	47	22	92	44201
49-047-200	1	4/4/2011	0.05	ppm	42	20	83	44201
49-047-200	1	4/5/2011	0.049	ppm	42	24	100	44201
49-047-200	1	4/6/2011	0.06	ppm	51	24	100	44201
49-047-200	1	4/7/2011	0.055	ppm	47	24	100	44201
49-047-200	1	4/8/2011	0.054	ppm	46	24	100	44201
49-047-200	1	4/9/2011	0.059	ppm	50	24	100	44201
49-047-200	1	4/10/2011	0.053	ppm	45	22	92	44201
49-047-200	1	4/11/2011	0.051	ppm	43	20	83	44201
49-047-200	1	4/12/2011	0.054	ppm	46	24	100	44201
49-047-200	1	4/13/2011	0.055	ppm	47	24	100	44201
49-047-200	1	4/14/2011	0.06	ppm	51	24	100	44201

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

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

49-047-200	1	2/3/2011	0.045	ppm	38	24	100	44201
49-047-200	1	2/4/2011	0.054	ppm	46	24	100	44201
49-047-200	1	2/5/2011	0.06	ppm	51	24	100	44201
49-047-200	1	2/6/2011	0.055	ppm	47	22	92	44201
49-047-200	1	2/7/2011	0.057	ppm	48	20	83	44201
49-047-200	1	2/8/2011	0.04	ppm	34	24	100	44201
49-047-200	1	2/9/2011	0.048	ppm	41	24	100	44201
49-047-200	1	2/10/2011	0.056	ppm	47	24	100	44201
49-047-200	1	2/11/2011	0.072	ppm	90	24	100	44201
49-047-200	1	2/12/2011	0.086	ppm	127	24	100	44201
49-047-200	1	2/13/2011	0.1	ppm	161	22	92	44201
49-047-200	1	2/14/2011	0.119	ppm	202	20	83	44201
49-047-200	1	2/15/2011	0.108	ppm	182	9	38	44201
49-047-200	1	2/16/2011	0.125	ppm	204	17	71	44201
49-047-200	1	2/17/2011	0.054	ppm	46	24	100	44201
49-047-200	1	2/18/2011	0.052	ppm	44	24	100	44201
49-047-200	1	2/19/2011	0.07	ppm	84	24	100	44201
49-047-200	1	2/20/2011	0.059	ppm	50	22	92	44201
49-047-200	1	2/21/2011	0.065	ppm	67	20	83	44201
49-047-200	1	2/22/2011	0.083	ppm	119	17	71	44201
49-047-200	1	2/23/2011	0.085	ppm	124	24	100	44201
49-047-200	1	2/24/2011	0.073	ppm	93	24	100	44201
49-047-200	1	2/25/2011	0.06	ppm	51	24	100	44201
49-047-200	1	2/26/2011	0.054	ppm	46	24	100	44201
49-047-200	1	2/27/2011	0.062	ppm	58	22	92	44201
49-047-200	1	2/28/2011	0.068	ppm	77	20	83	44201
49-047-200	1	3/1/2011	0.092	ppm	142	24	100	44201
49-047-200	1	3/2/2011	0.08	ppm	111	24	100	44201
49-047-200	1	3/3/2011	0.077	ppm	104	24	100	44201
49-047-200	1	3/4/2011	0.058	ppm	49	24	100	44201
49-047-200	1	3/5/2011	0.055	ppm	47	24	100	44201
49-047-200	1	3/6/2011	0.05	ppm	42	22	92	44201
49-047-200	1	3/7/2011	0.052	ppm	44	20	83	44201
49-047-200	1	3/8/2011	0.051	ppm	43	24	100	44201
49-047-200	1	3/9/2011	0.051	ppm	43	24	100	44201
49-047-200	1	3/10/2011	0.052	ppm	44	24	100	44201
49-047-200	1	3/11/2011	0.051	ppm	43	24	100	44201
49-047-200	1	3/12/2011	0.047	ppm	40	24	100	44201
49-047-200	1	3/13/2011	0.054	ppm	46	22	92	44201
49-047-200	1	3/14/2011	0.049	ppm	42	20	83	44201
49-047-200	1	3/15/2011	0.049	ppm	42	24	100	44201
49-047-200	1	3/16/2011	0.042	ppm	36	24	100	44201
49-047-200	1	3/17/2011	0.047	ppm	40	24	100	44201
49-047-200	1	3/18/2011	0.052	ppm	44	24	100	44201
49-047-200	1	3/19/2011	0.051	ppm	43	24	100	44201
49-047-200	1	3/20/2011	0.05	ppm	42	22	92	44201
49-047-200	1	3/21/2011	0.05	ppm	42	20	83	44201
49-047-200	1	3/23/2011	0.049	ppm	42	24	100	44201
49-047-200	1	3/24/2011	0.053	ppm	45	24	100	44201
49-047-200	1	3/25/2011	0.047	ppm	40	24	100	44201
49-047-200	1	3/26/2011	0.048	ppm	41	24	100	44201
49-047-200	1	3/27/2011	0.052	ppm	44	22	92	44201

49-047-20(	1	3/28/2011	0.049	ppm	42	20	83	44201
49-047-20(	1	3/29/2011	0.047	ppm	40	24	100	44201
49-047-20(	1	3/30/2011	0.042	ppm	36	24	100	44201
49-047-20(	1	3/31/2011	0.045	ppm	38	20	83	44201
49-047-20(	1	4/1/2011	0.053	ppm	45	24	100	44201
49-047-20(	1	4/2/2011	0.045	ppm	38	24	100	44201
49-047-20(	1	4/3/2011	0.055	ppm	47	22	92	44201
49-047-20(	1	4/4/2011	0.05	ppm	42	20	83	44201
49-047-20(	1	4/5/2011	0.043	ppm	36	24	100	44201
49-047-20(	1	4/6/2011	0.059	ppm	50	24	100	44201
49-047-20(	1	4/7/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	4/8/2011	0.051	ppm	43	24	100	44201
49-047-20(	1	4/9/2011	0.059	ppm	50	24	100	44201
49-047-20(	1	4/10/2011	0.053	ppm	45	22	92	44201
49-047-20(	1	4/11/2011	0.052	ppm	44	20	83	44201
49-047-20(	1	4/12/2011	0.053	ppm	45	24	100	44201
49-047-20(	1	4/13/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	4/14/2011	0.059	ppm	50	24	100	44201
49-047-20(	1	4/15/2011	0.063	ppm	61	24	100	44201
49-047-20(	1	4/16/2011	0.051	ppm	43	24	100	44201
49-047-20(	1	4/17/2011	0.045	ppm	38	22	92	44201
49-047-20(	1	4/18/2011	0.032	ppm	27	20	83	44201
49-047-20(	1	4/19/2011	0.047	ppm	40	24	100	44201
49-047-20(	1	4/20/2011	0.046	ppm	39	24	100	44201
49-047-20(	1	4/21/2011	0.05	ppm	42	24	100	44201
49-047-20(	1	4/22/2011	0.058	ppm	49	24	100	44201
49-047-20(	1	4/23/2011	0.057	ppm	48	24	100	44201
49-047-20(	1	4/24/2011	0.046	ppm	39	22	92	44201
49-047-20(	1	4/25/2011	0.051	ppm	43	20	83	44201
49-047-20(	1	4/26/2011	0.053	ppm	45	24	100	44201
49-047-20(	1	4/27/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	4/28/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	4/29/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	4/30/2011	0.045	ppm	38	24	100	44201
49-047-20(	1	5/1/2011	0.05	ppm	42	22	92	44201
49-047-20(	1	5/2/2011	0.056	ppm	47	20	83	44201
49-047-20(	1	5/3/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	5/5/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	5/6/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	5/7/2011	0.063	ppm	61	24	100	44201
49-047-20(	1	5/8/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	5/9/2011	0.062	ppm	58	24	100	44201
49-047-20(	1	5/10/2011	0.057	ppm	48	24	100	44201
49-047-20(	1	5/11/2011	0.039	ppm	33	24	100	44201
49-047-20(	1	5/12/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	5/13/2011	0.048	ppm	41	24	100	44201
49-047-20(	1	5/14/2011	0.047	ppm	40	24	100	44201
49-047-20(	1	5/15/2011	0.044	ppm	37	24	100	44201
49-047-20(	1	5/16/2011	0.05	ppm	42	24	100	44201
49-047-20(	1	5/17/2011	0.051	ppm	43	24	100	44201
49-047-20(	1	5/18/2011	0.053	ppm	45	24	100	44201
49-047-20(								

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

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Ozone	0	Not in a CM	0	Not in a MS	49	Utah	47	Uintah
				Not in a MS				

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Ozone	0	Not in a CM	0	Not in a MS	49	Utah	47	Uintah
Ozone	0	Not in a CM	0	Not in a MS	49	Utah	47	Uintah
				Not in a MS				

CITY_CO	CITY	UAR_COD	UAR	LATITUDE	LONGITUD	LOCATION	LANDUSE	ELEVATIO
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GASCO ENERGY INC.

Uinta Basin Natural Gas Development Project

DRAFT ENVIRONMENTAL IMPACT STATEMENT
VOLUME 1: EXECUTIVE SUMMARY AND CHAPTERS 1–5

BLM

Vernal Field Office

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT
NATIONAL SYSTEM OF PUBLIC LANDS

OCTOBER 2010
DES 10-33

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

3.2.3.1.5.1 $PM_{2.5}$ Air Monitoring

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

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

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

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

3.2.3.1.5.2 Ozone Air Monitoring

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

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

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

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

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

4.2 AIR QUALITY

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

4.2.1 NEAR-FIELD AIR QUALITY

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

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

4.2.1.1 DEVELOPMENT

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

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

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

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

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

4.2.1.1.1 Development Impacts

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

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

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

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

4.2.1.2.4 Summary of Operations Impacts

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

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

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

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

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

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

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

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

Ozone Impact Assessment

for

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

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

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

and

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

April 2010

1.0 Introduction

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

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

1.1 Project Description

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

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

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

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

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

Up to 10 drilling rigs operating year round;

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

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

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

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

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

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

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

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

Vehicle tailpipe emissions associated with all development phases;

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

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

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

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

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

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

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

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

Oil and Gas Exploration and Production Emission Sources

Presentation for the

Air Quality Control Commission Retreat

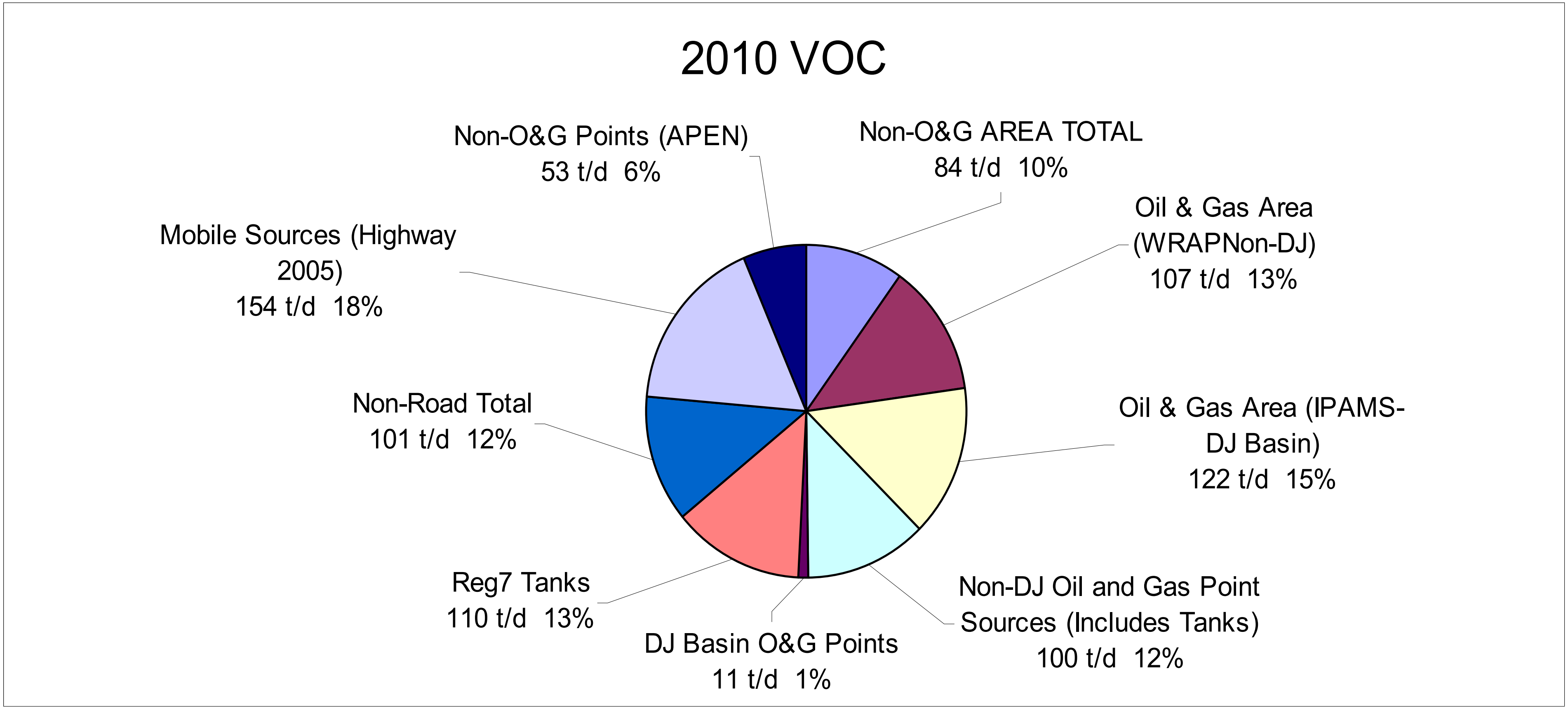
May 15, 2008

Air Pollution Control Division

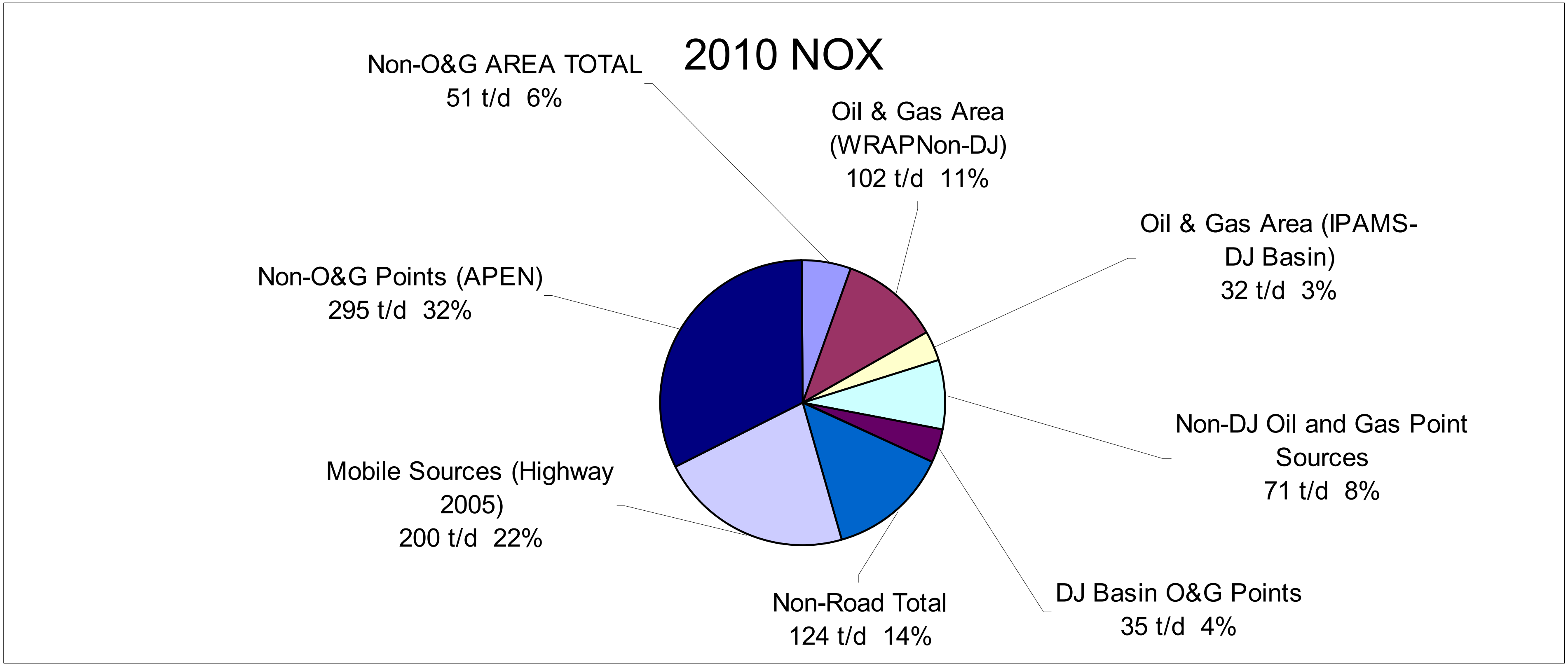
Approach to Statewide Oil and Gas Control Strategy Development

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

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



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



Approach to Statewide Oil and Gas Control Strategy Development

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

Elimination of Categorical Exemptions for Oil and Gas Sources

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

CONSERVATION COMMISSION

COLORADO

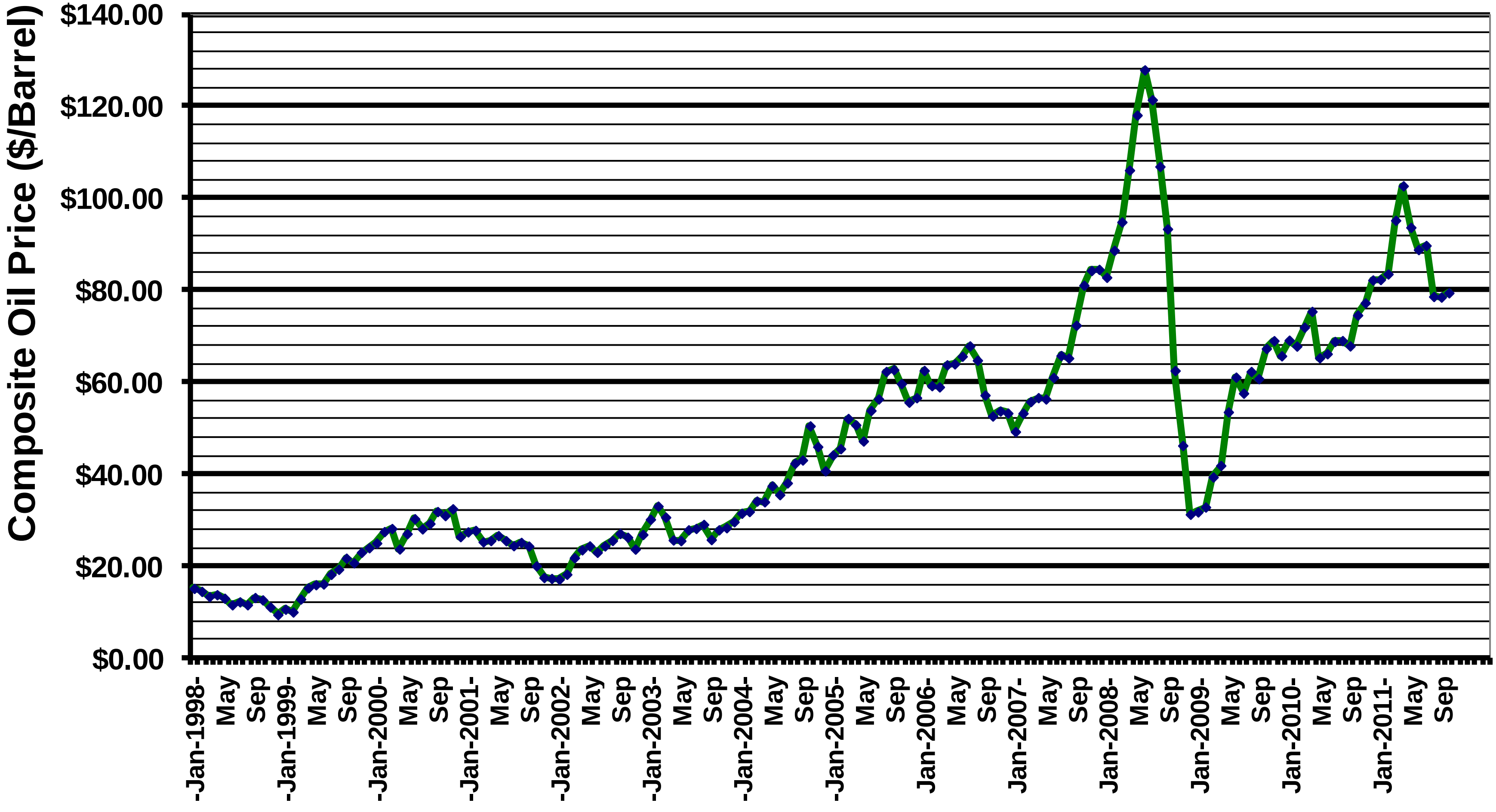
WEEKLY & MONTHLY

OIL & GAS STATISTICS

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

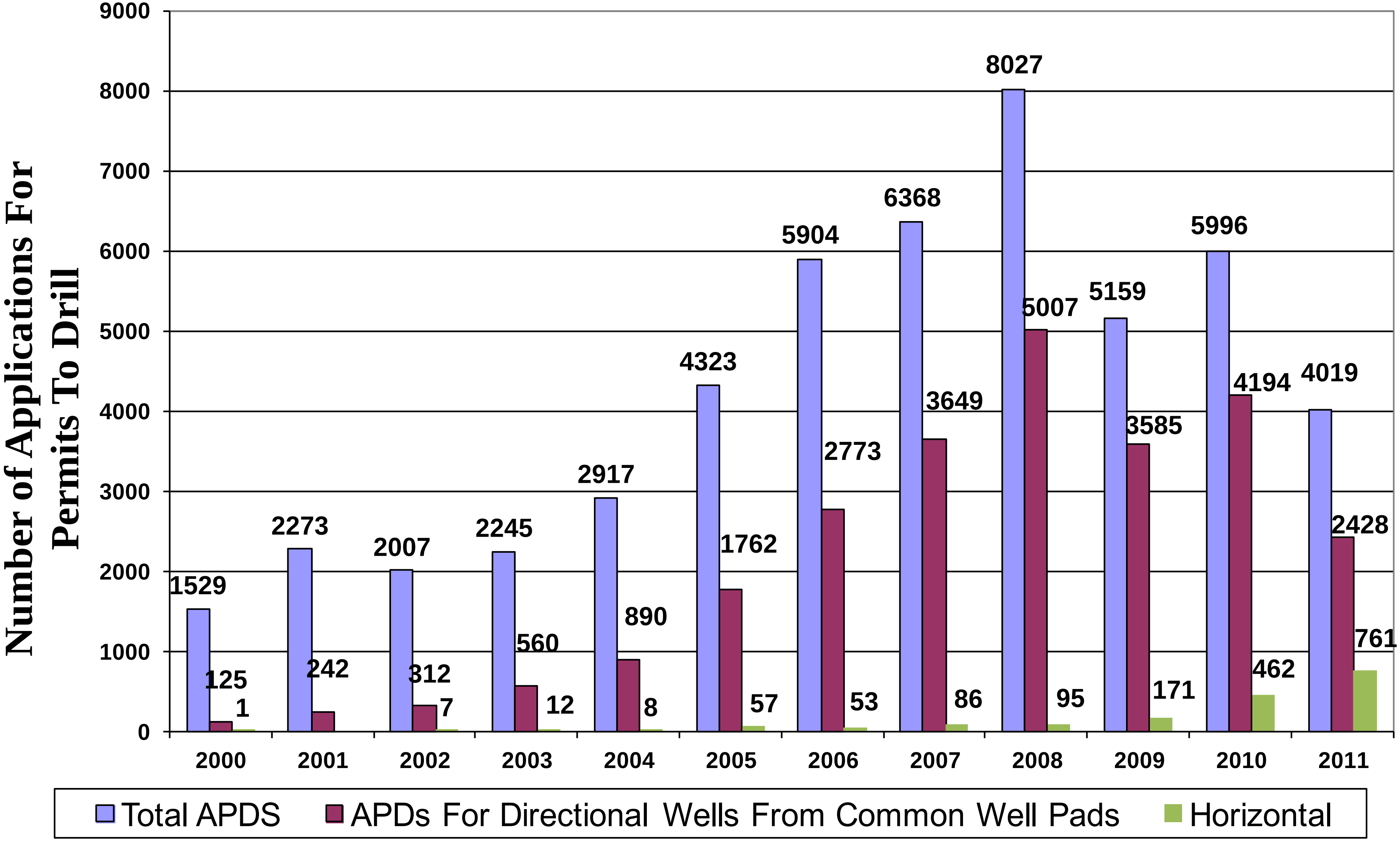
Colorado Monthly Composite Oil Price

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

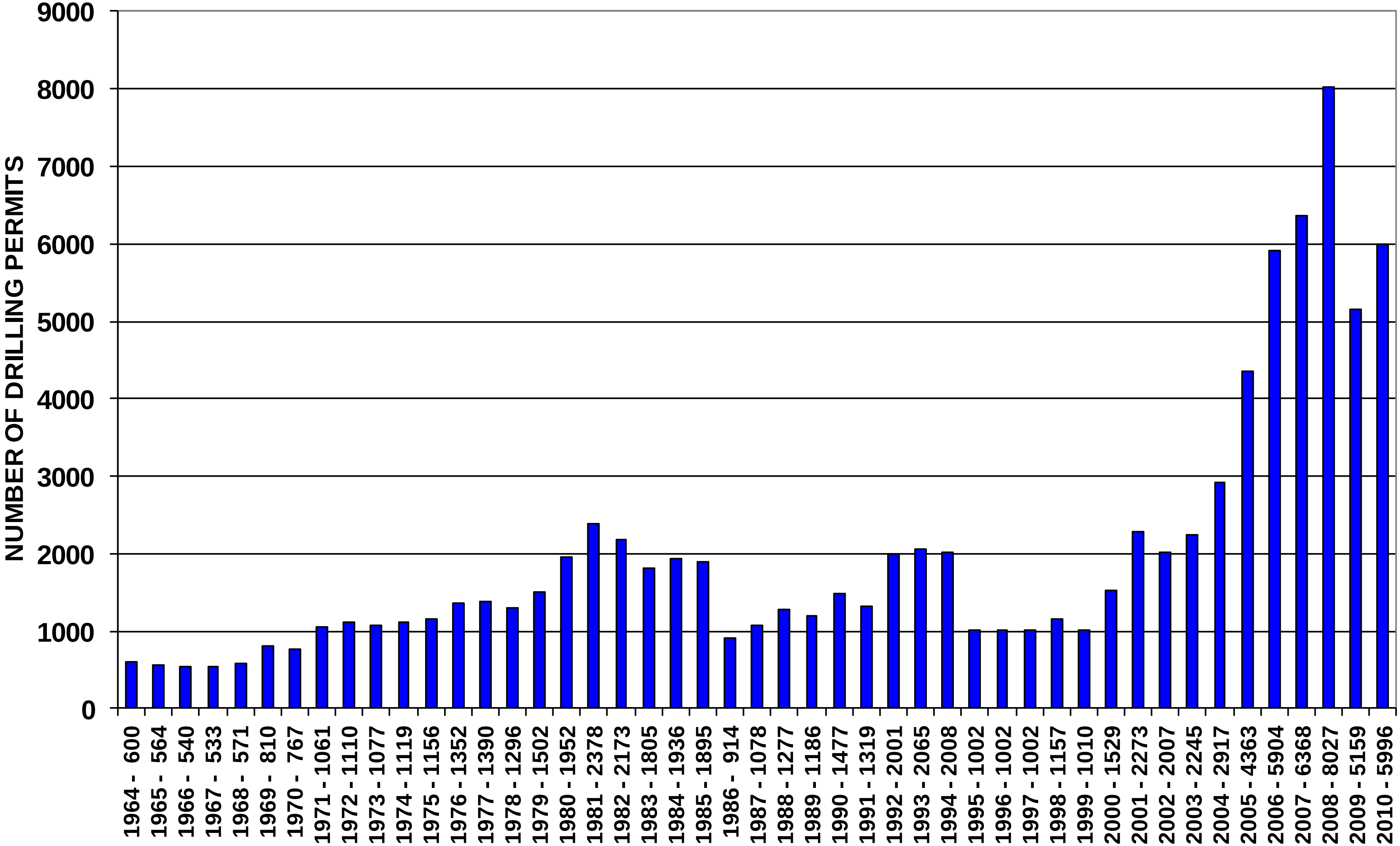


Number of Oil and Gas Well Permits For Wells Drilled Directionally & Horizontally From Common Well Pads in Colorado

11-07-11

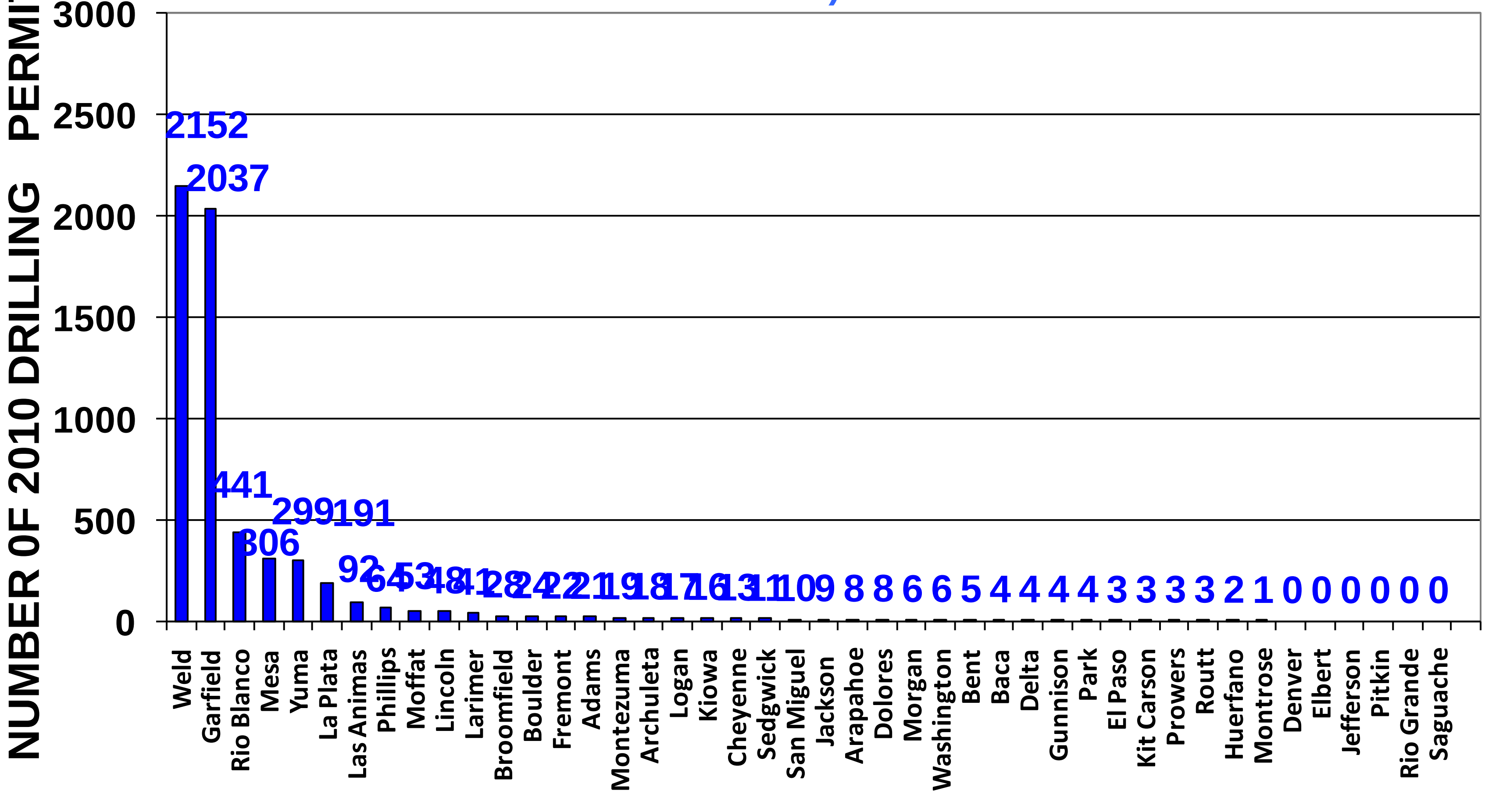


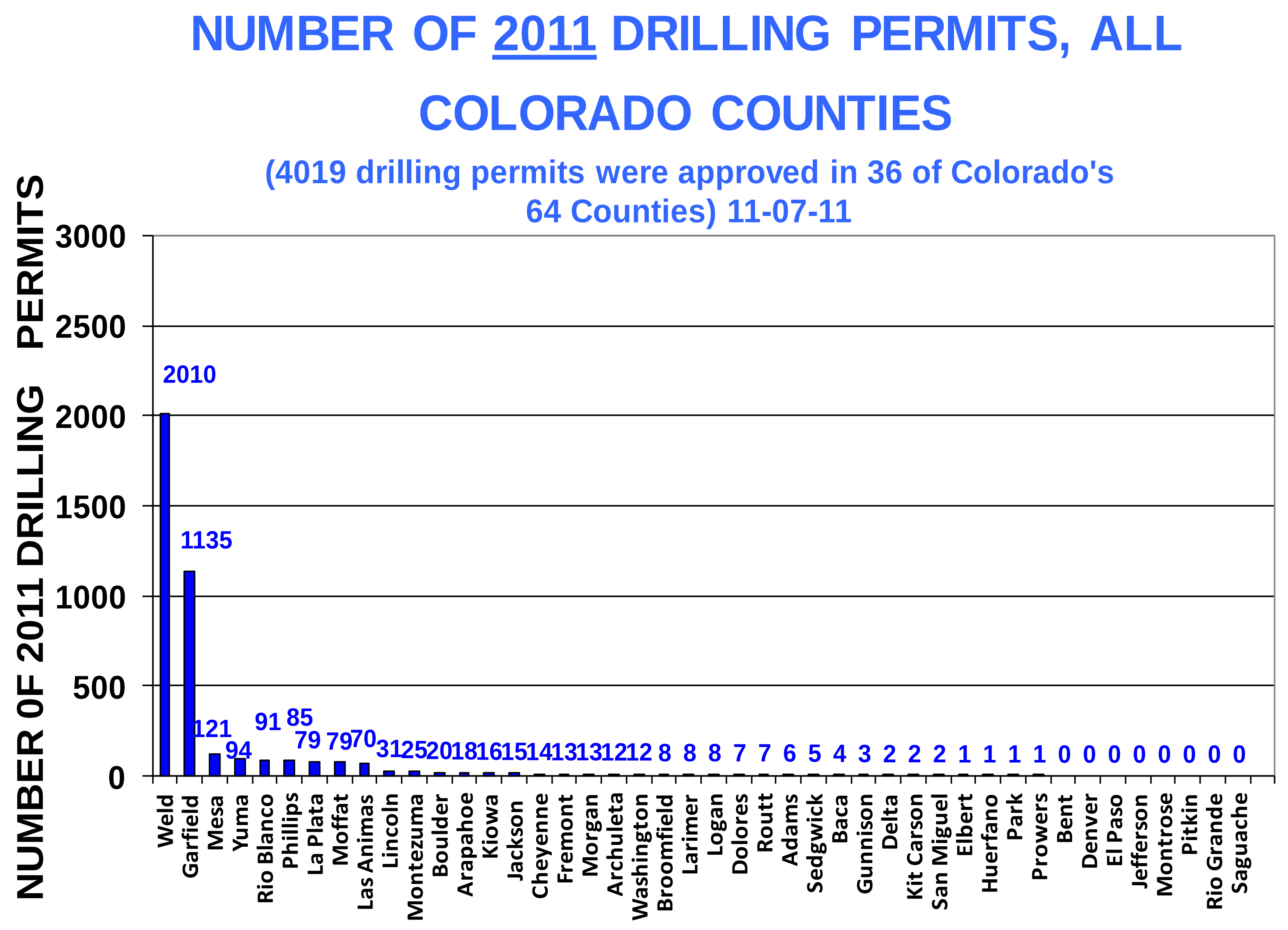
HISTORIC ANNUAL COLORADO DRILLING PERMITS 11-07-11



NUMBER OF <u>2010</u> DRILLING PERMITS, ALL COLORADO COUNTIES

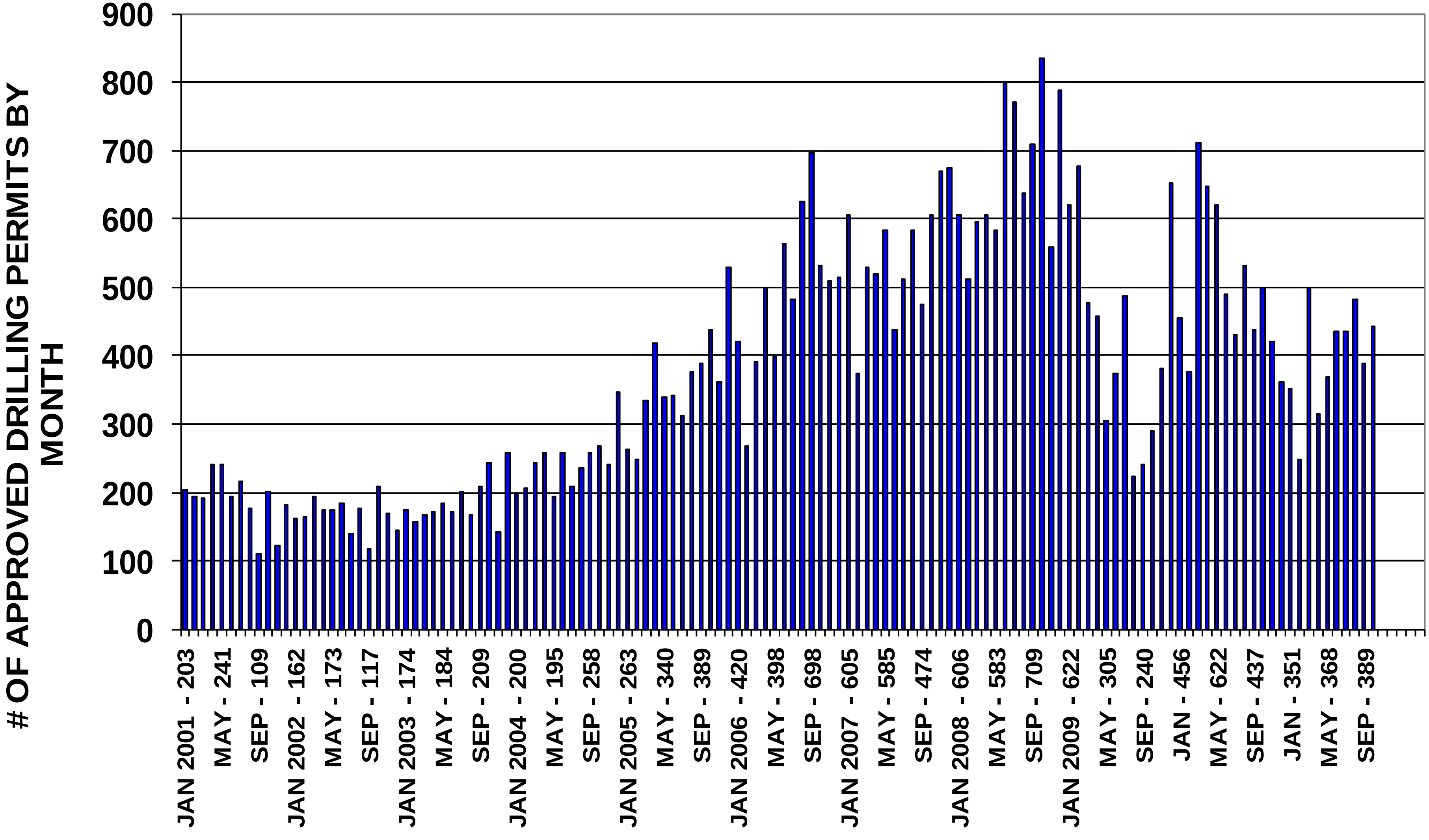
(5,996 drilling permits were approved in 38 of Colorado's 64 Counties) 01-07-11



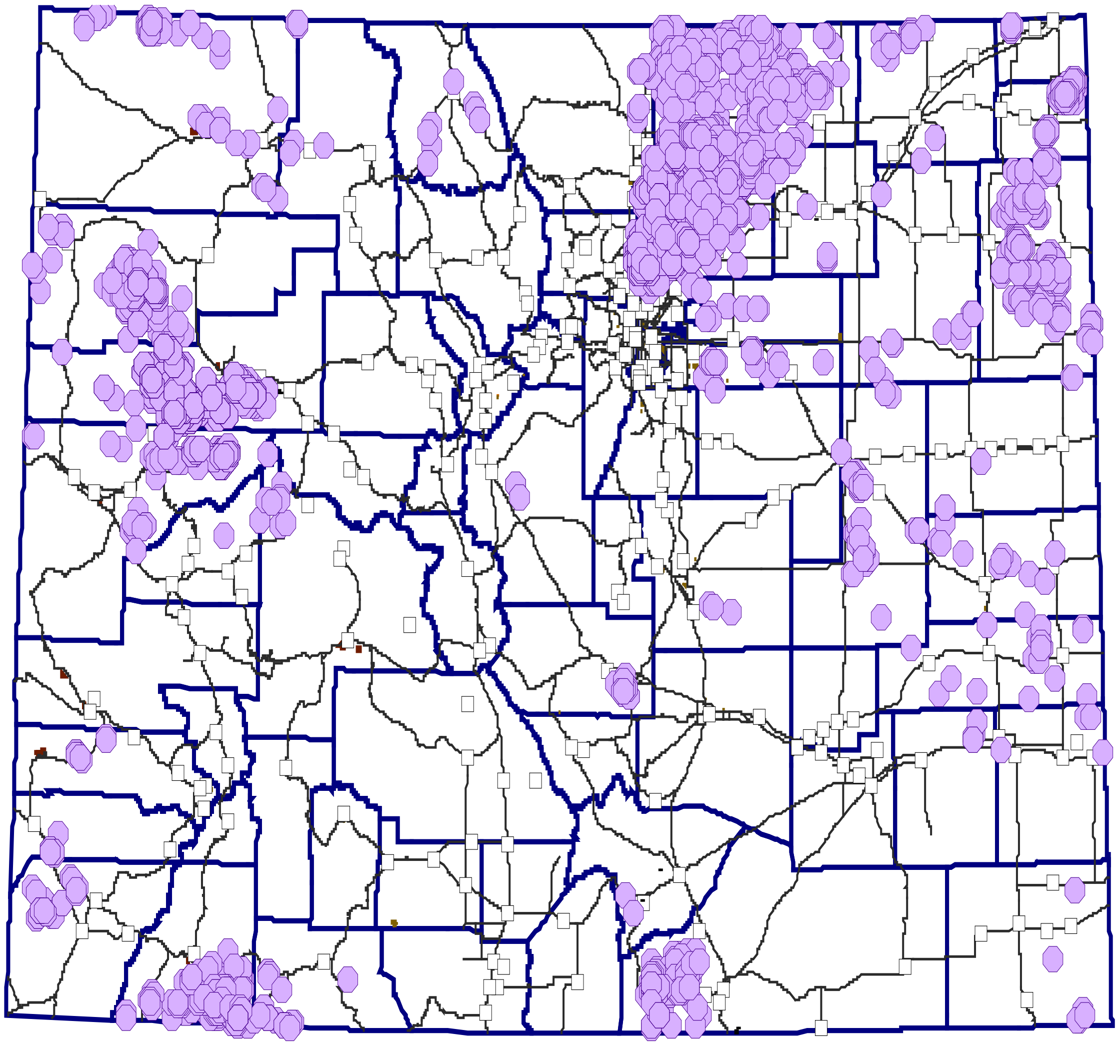

NUMBER OF 2011 DRILLING PERMITS, ALL
COLORADO COUNTIES
(4019 drilling permits were approved in 36 of Colorado's
64 Counties) 11-07-11
NUMBER 0F 2011 DRILLING PERMITS
3000
2500
2000
1500
1000
500
0
2010
1135
121
94
91
85
79
79
70
31
25
20
18
16
15
14
13
13
12
12
8
8
8
7
7
6
5
4
3
2
2
2
1
1
1
1
0
0
0
0
0
0
0
0
Weld
Garfield
Mesa
Yuma
Rio Blanco
Phillips
La Plata
Moffat
Las Animas
Lincoln
Montezuma
Boulder
Arapahoe
Kiowa
Jackson
Cheyenne
Fremont
Morgan
Archuleta
Washington
Broomfield
Larimer
Logan
Dolores
Routt
Adams
Sedgwick
Baca
Gunnison
Delta
Kit Carson
San Miguel
Elbert
Huerfano
Park
Prowers
Bent
Denver
El Paso
Jefferson
Montrose
Pitkin
Rio Grande
Saguache

COLORADO MONTHLY APPROVED DRILLING PERMITS

as of 11-07-11

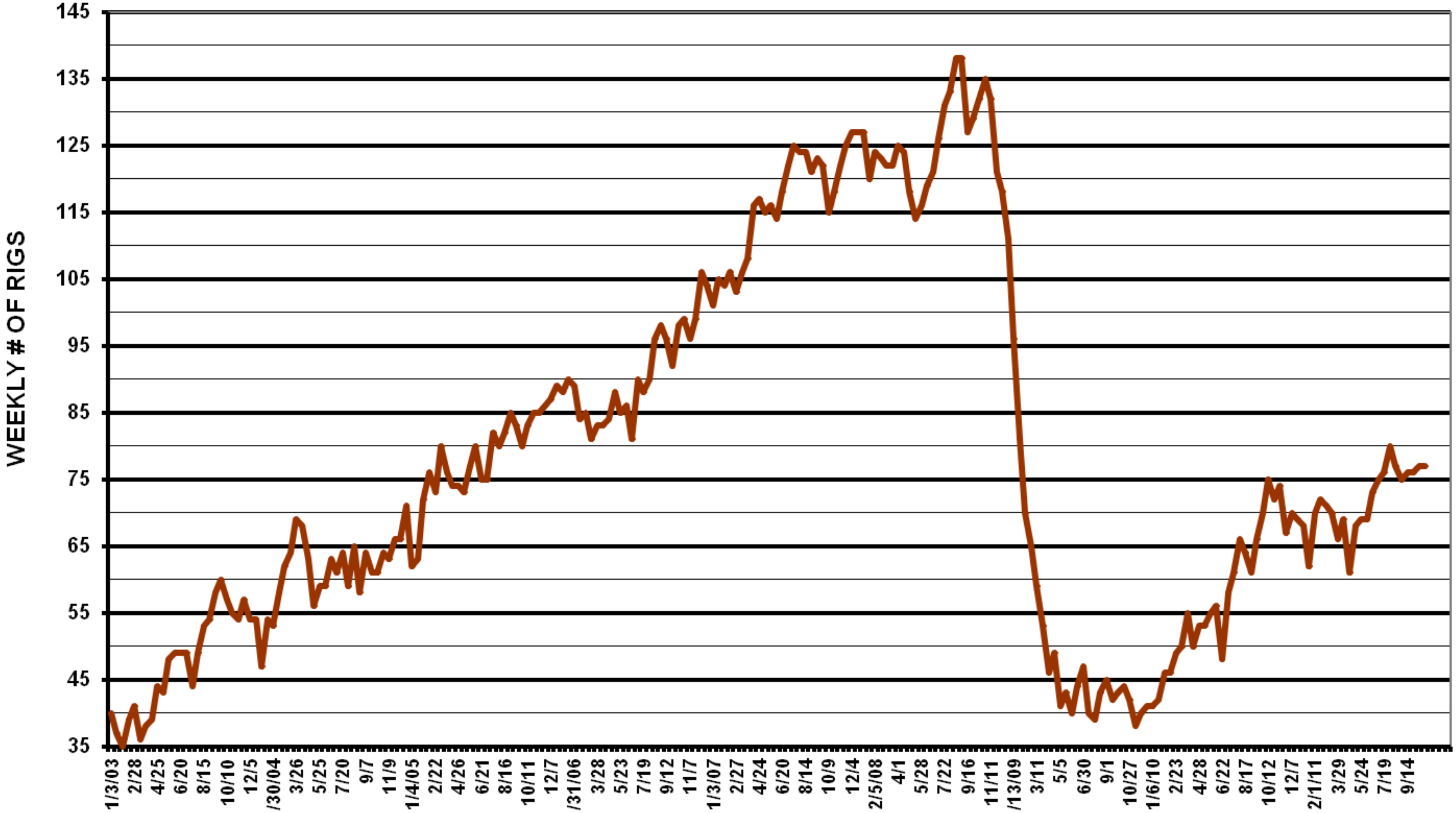


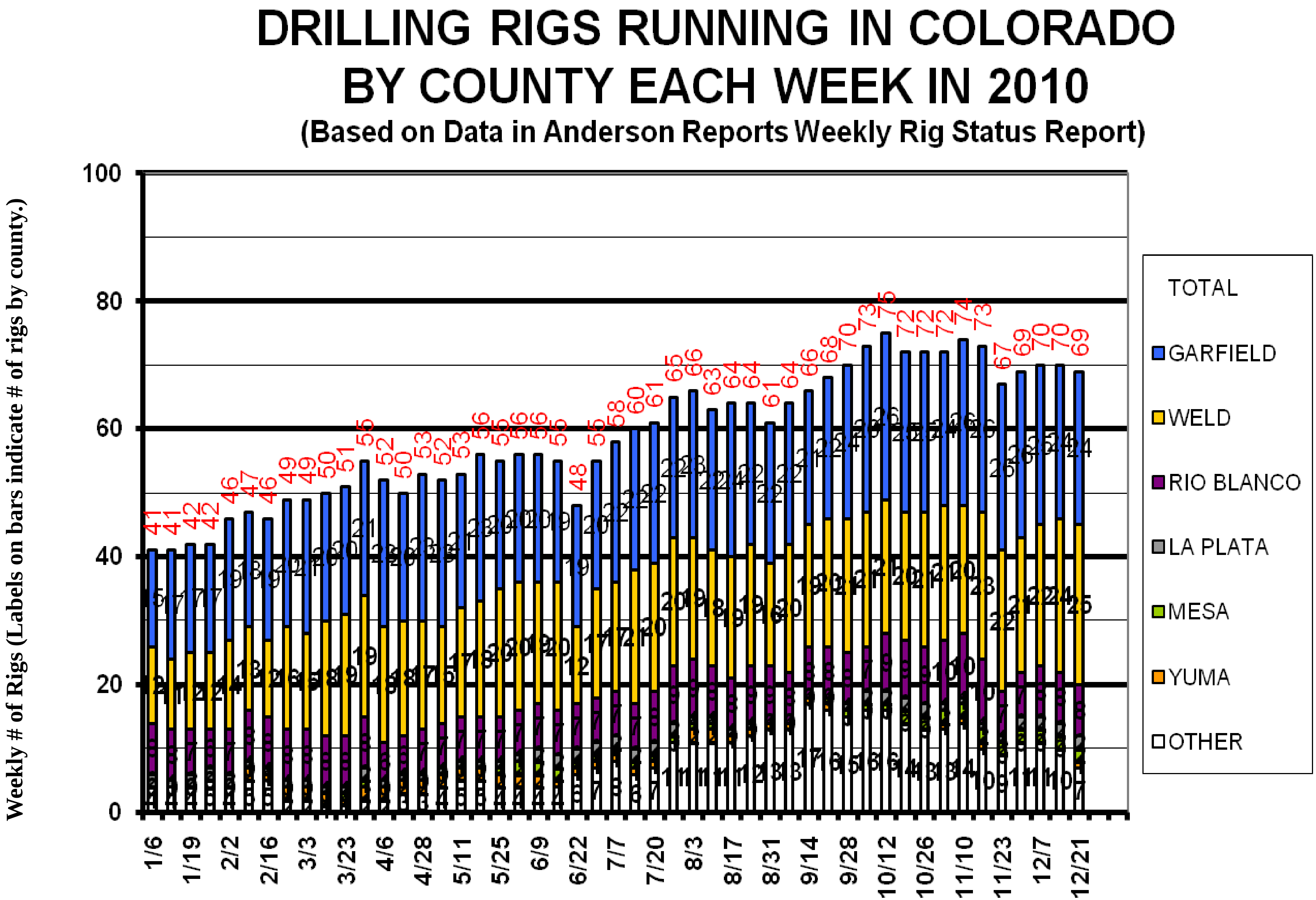
RECENT COLORADO OIL AND GAS WELL PERMITS 11-07-11



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

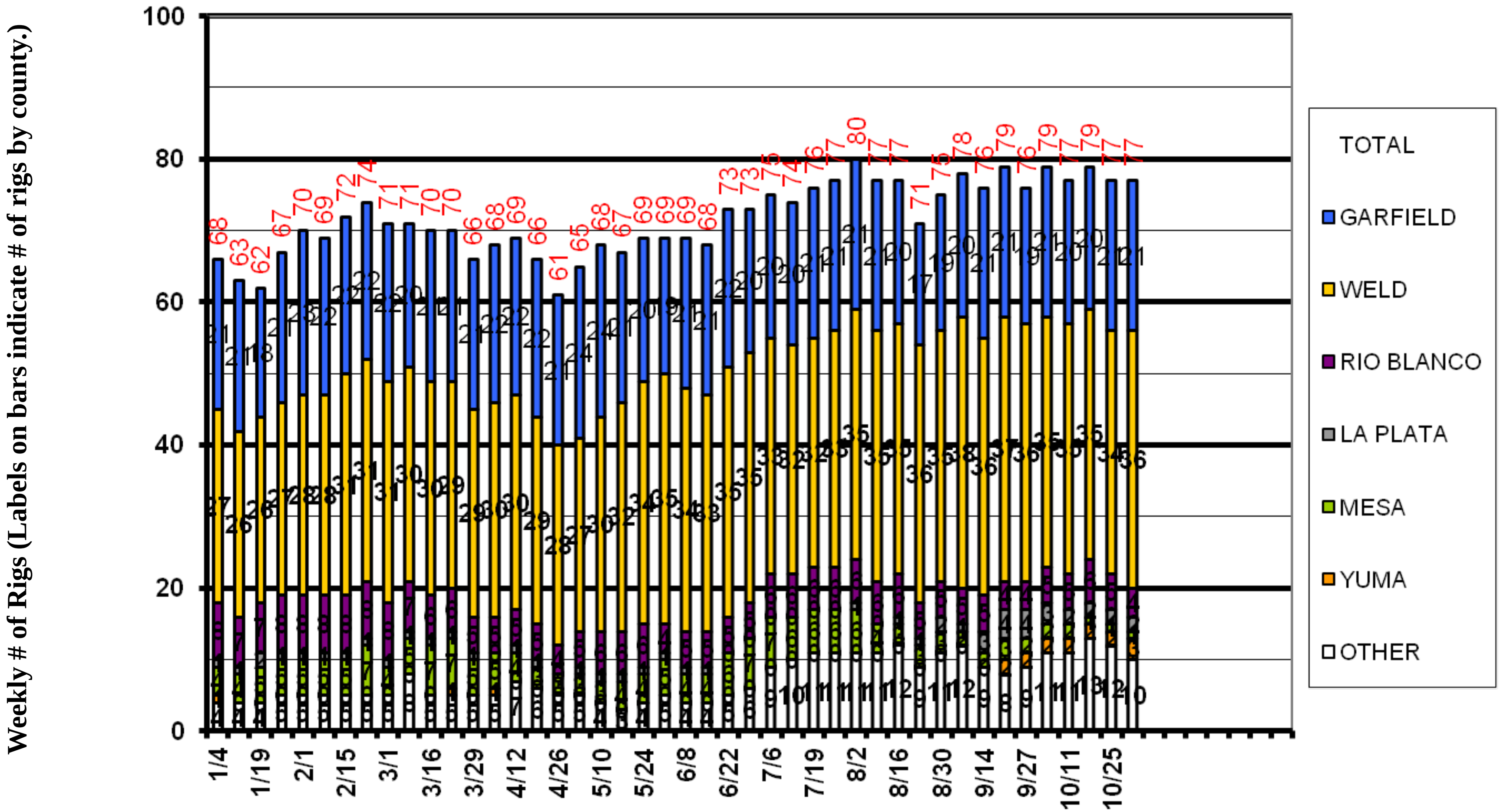
(Based on Data in: through 4/30/03, PI/Dwights Drilling Wire -- after 4/30/03, Anderson Reports Weekly Rig Status Report)

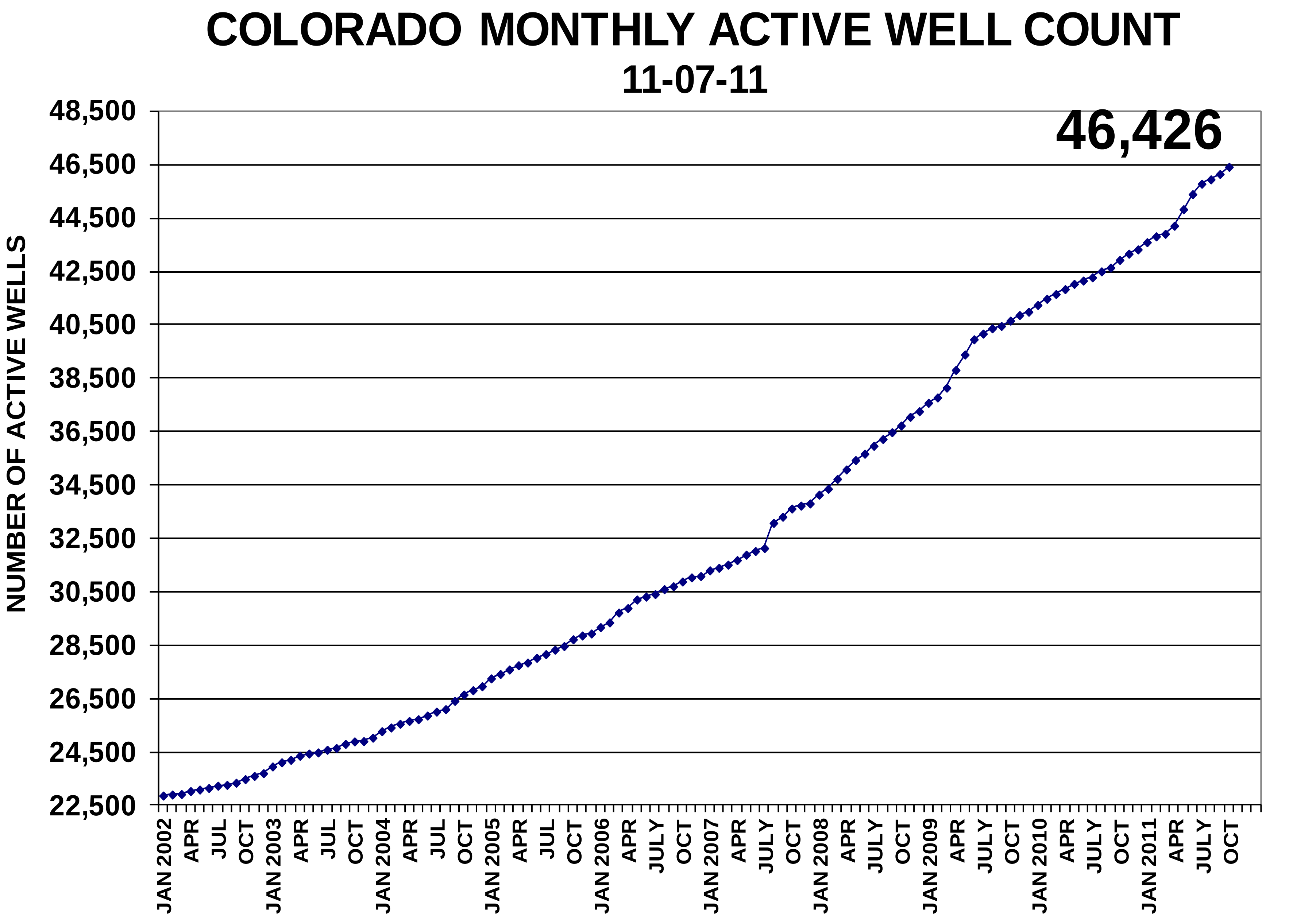



DRILLING RIGS RUNNING IN COLORADO
BY COUNTY EACH WEEK IN 2010
(Based on Data in Anderson Reports Weekly Rig Status Report)
Weekly # of Rigs (Labels on bars indicate # of rigs by county.)
100
80
60
40
20
0
1/6
1/19
2/2
2/16
3/3
3/23
4/6
4/28
5/11
5/25
6/9
6/22
7/7
7/20
8/3
8/17
8/31
9/14
9/28
10/12
10/26
11/10
11/23
12/7
12/21
TOTAL
GARFIELD
WELD
RIO BLANCO
LA PLATA
MESA
YUMA
OTHER

DRILLING RIGS RUNNING IN COLORADO BY COUNTY EACH WEEK IN 2011

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

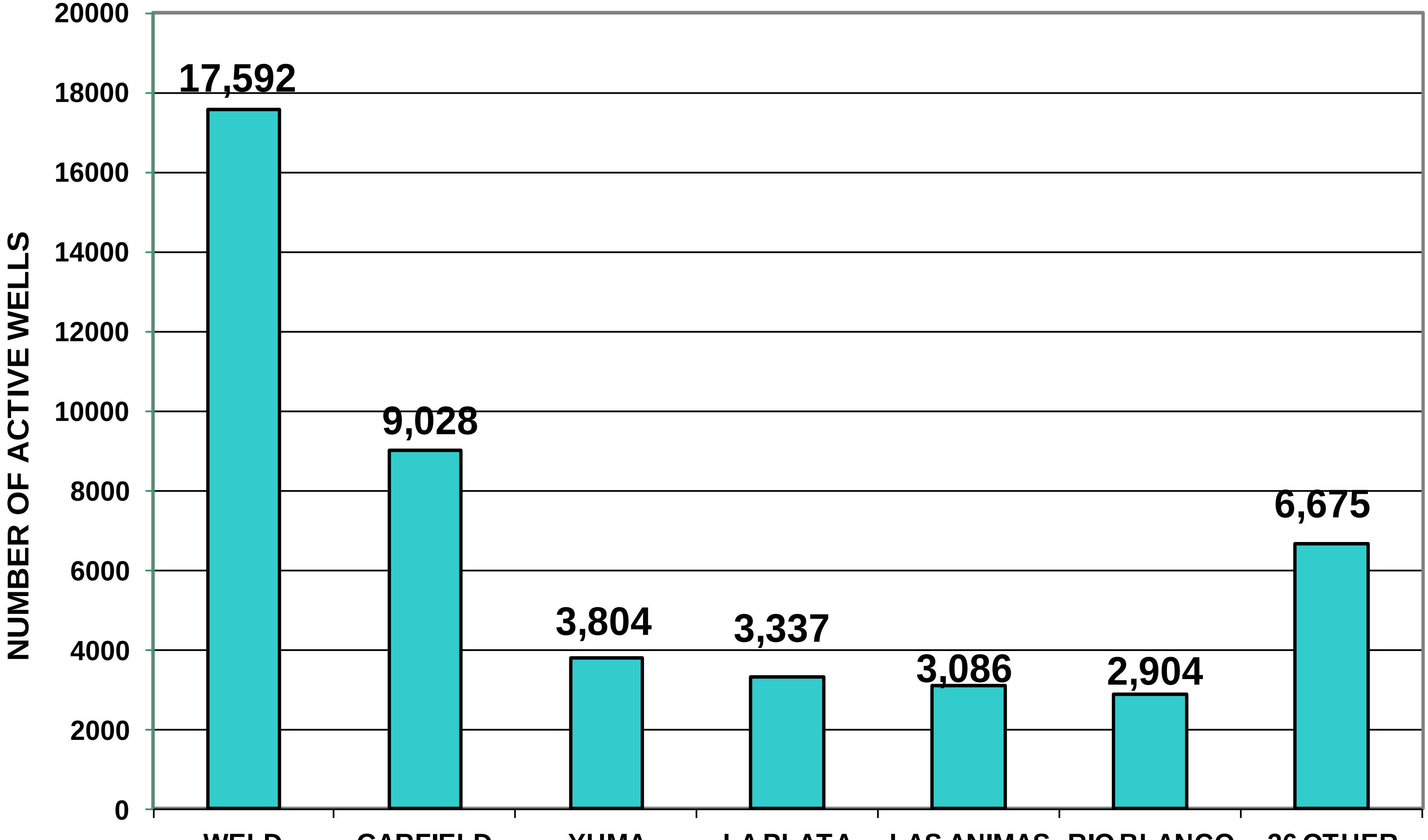



COLORADO MONTHLY ACTIVE WELL COUNT
11-07-11
46,426
NUMBER OF ACTIVE WELLS
48,500
46,500
44,500
42,500
40,500
38,500
36,500
34,500
32,500
30,500
28,500
26,500
24,500
22,500
JAN 2002
APR
JUL
OCT
JAN 2003
APR
JUL
OCT
JAN 2004
APR
JUL
OCT
JAN 2005
APR
JUL
OCT
JAN 2006
APR
JULY
OCT
JAN 2007
APR
JULY
OCT
JAN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

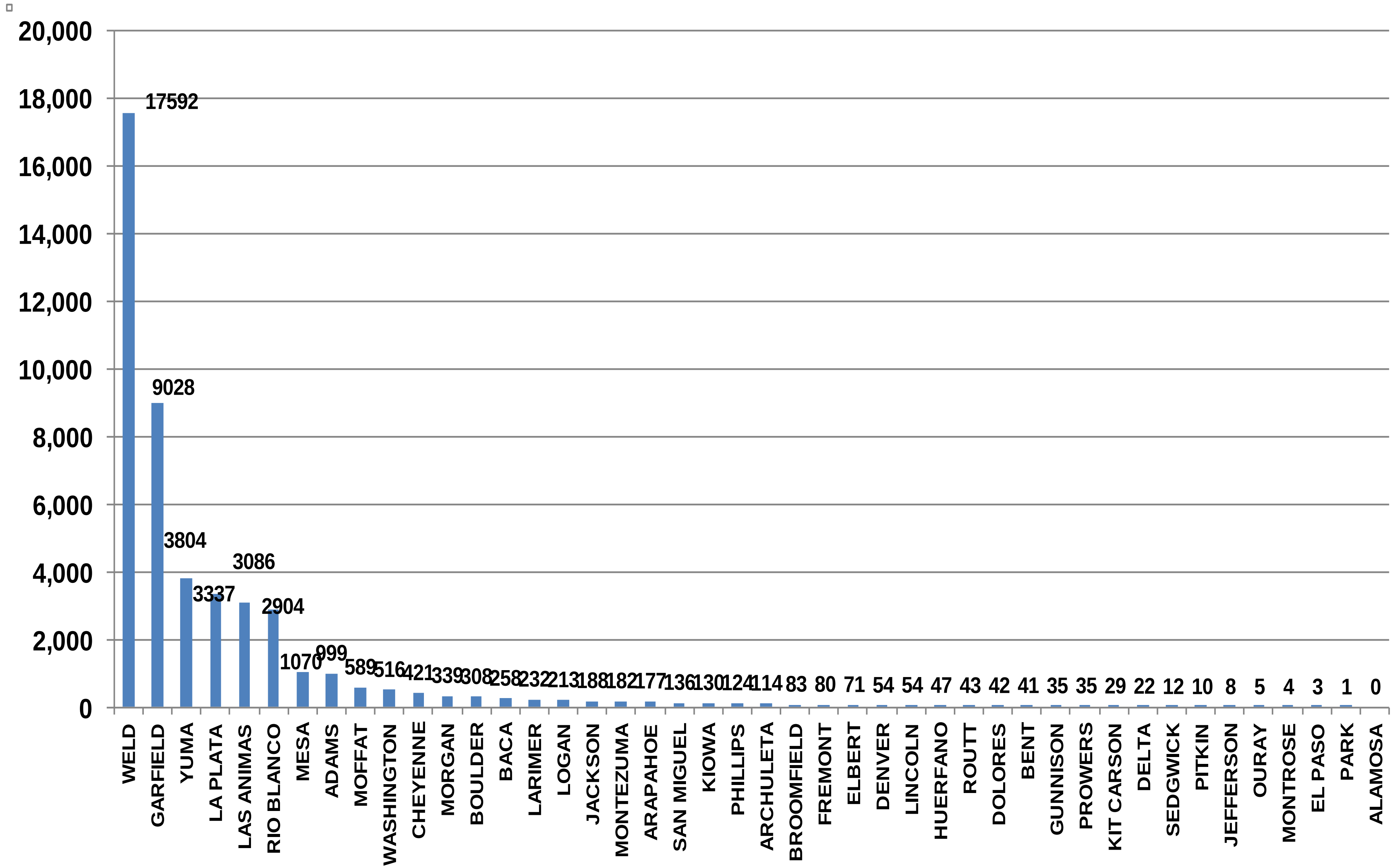
NUMBER OF ACTIVE COLORADO OIL & GAS WELLS BY COUNTY

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

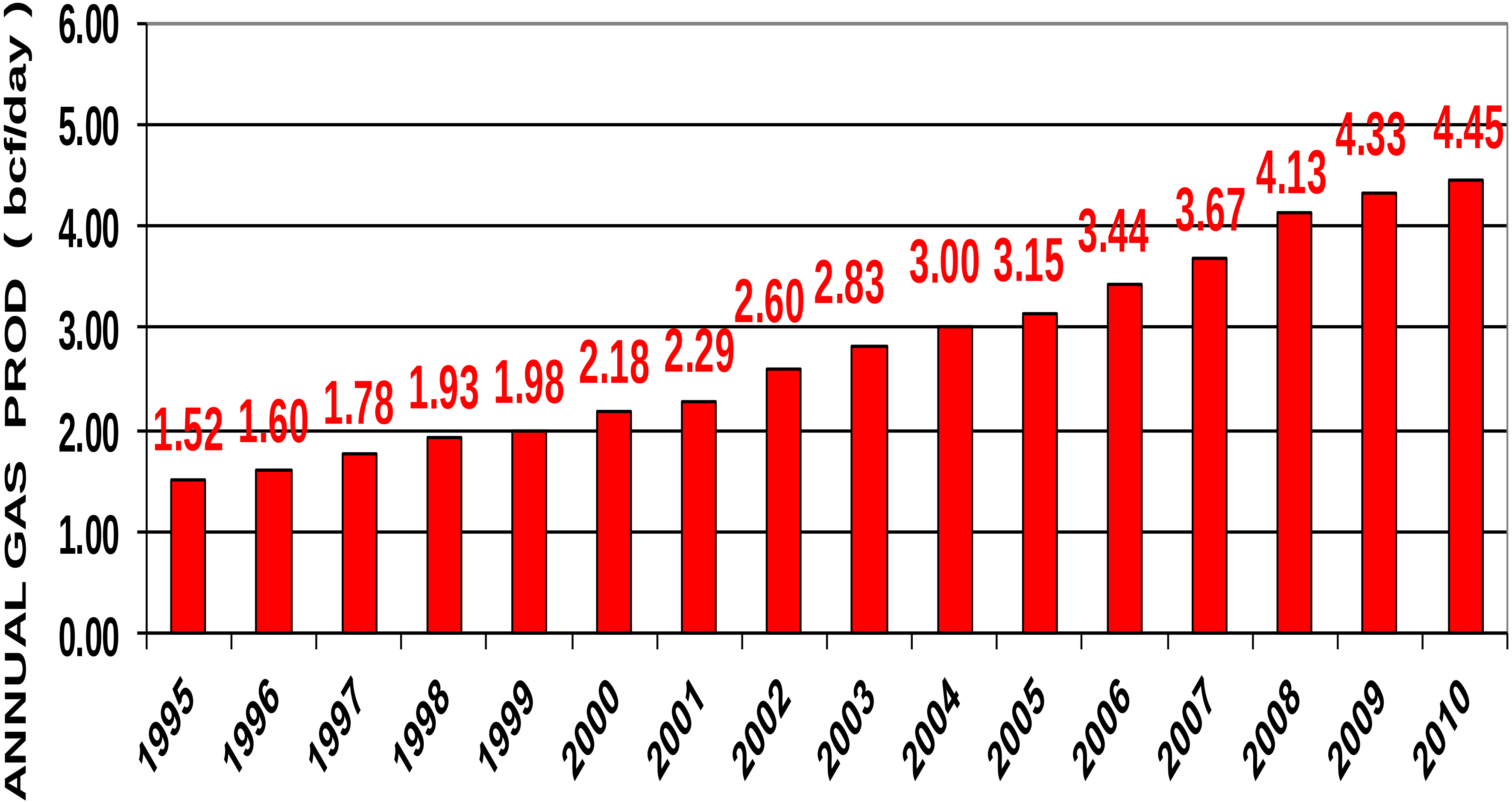
(11-07-11)

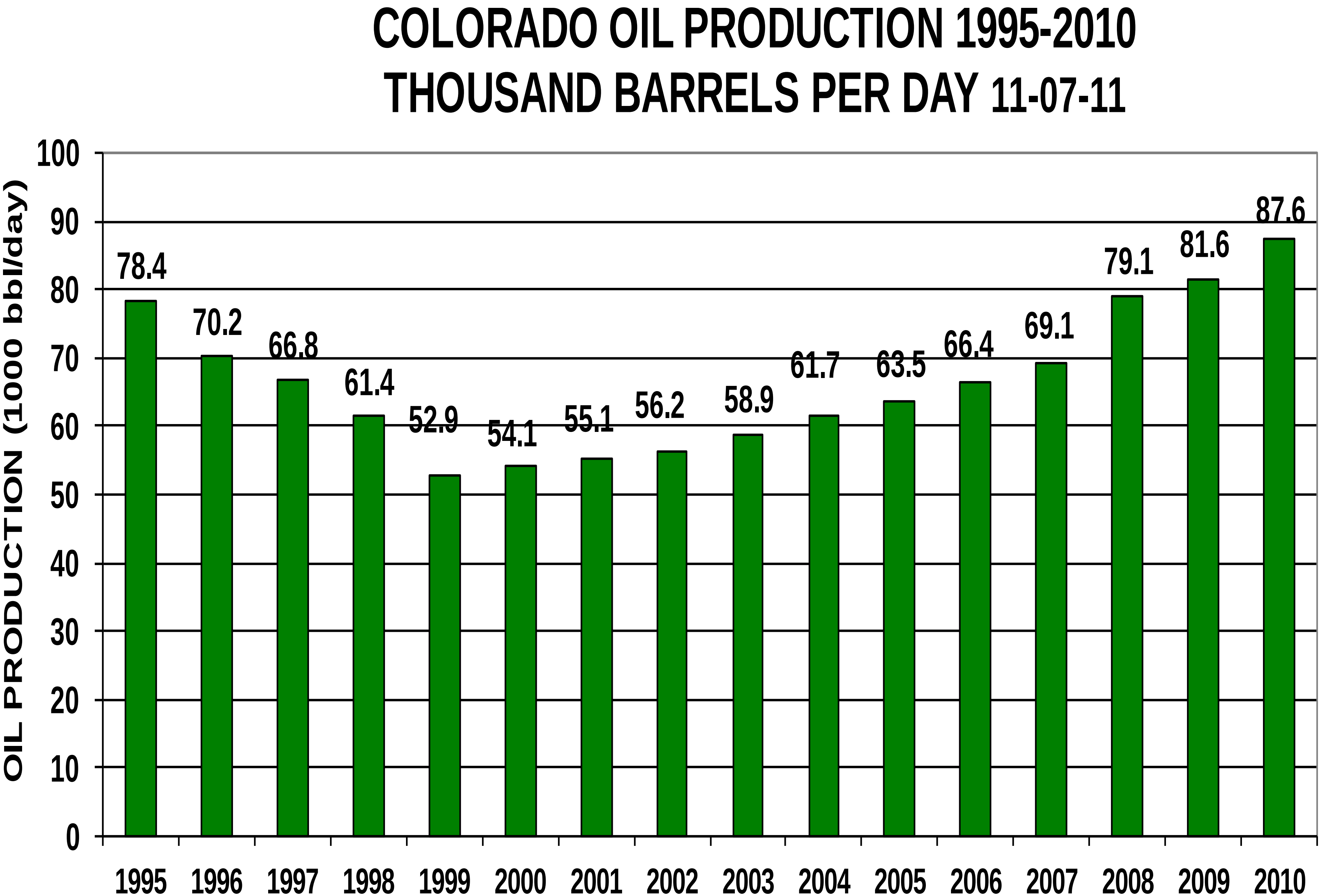


ACTIVE OIL & GAS WELLS – ALL COLORADO COUNTIES
11-07-11



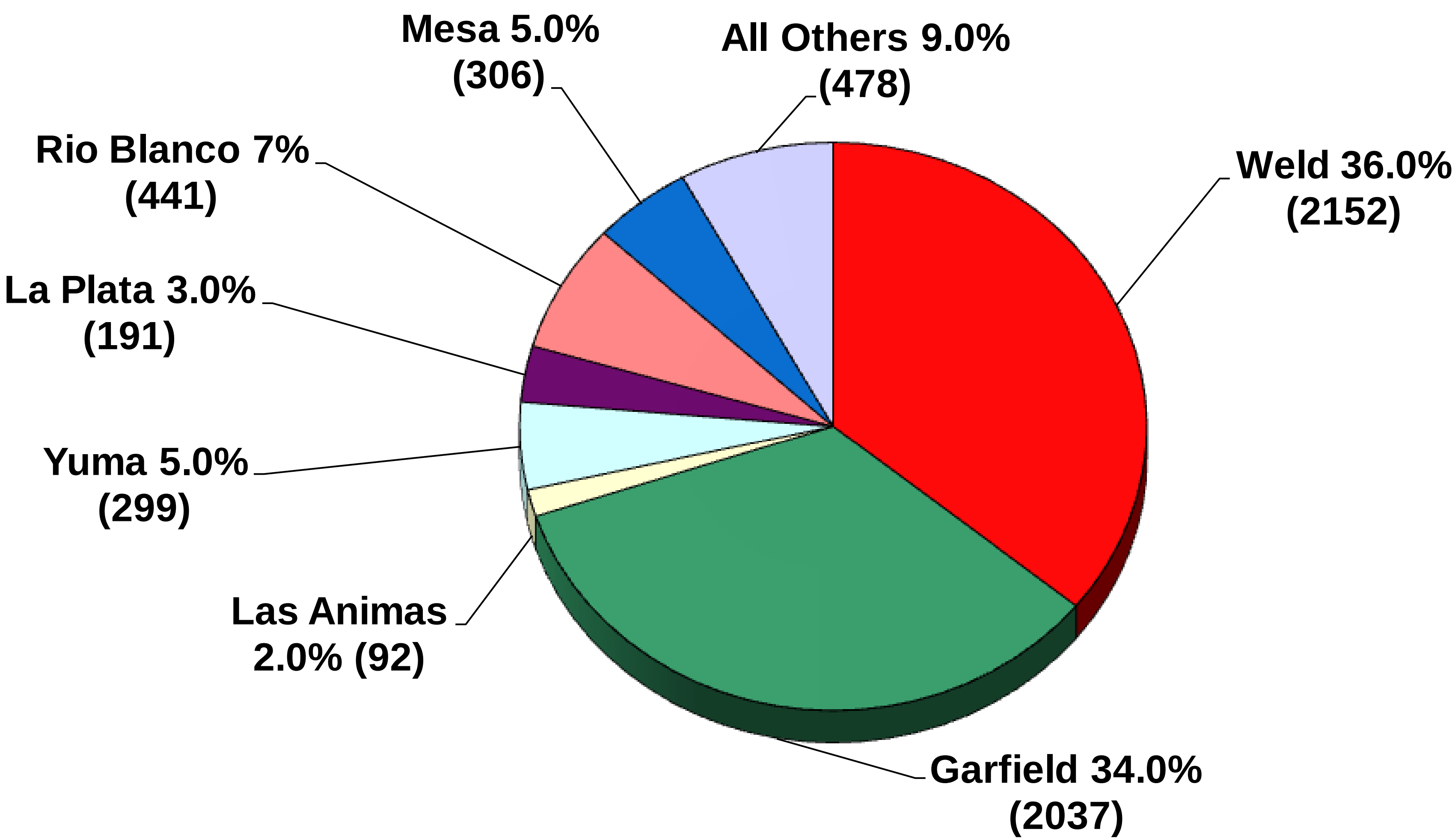
COLORADO NATURAL GAS PRODUCTION
1995-2010
BILLION CUBIC FEET OF GAS PER DAY 11-07-11




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

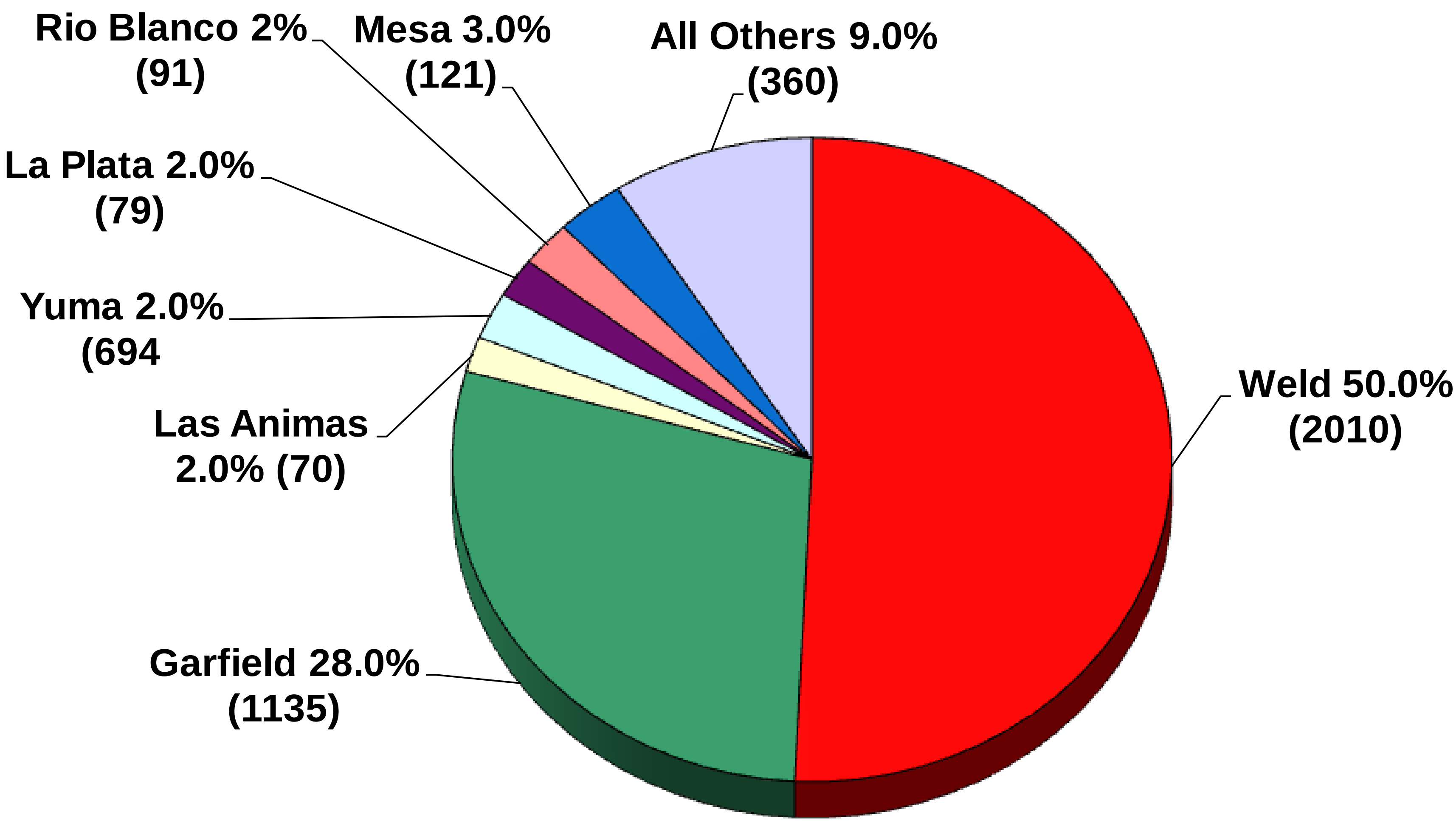
COLORADO OIL AND GAS 2010 DRILLING PERMITS BY COUNTY

as of 01-07-11

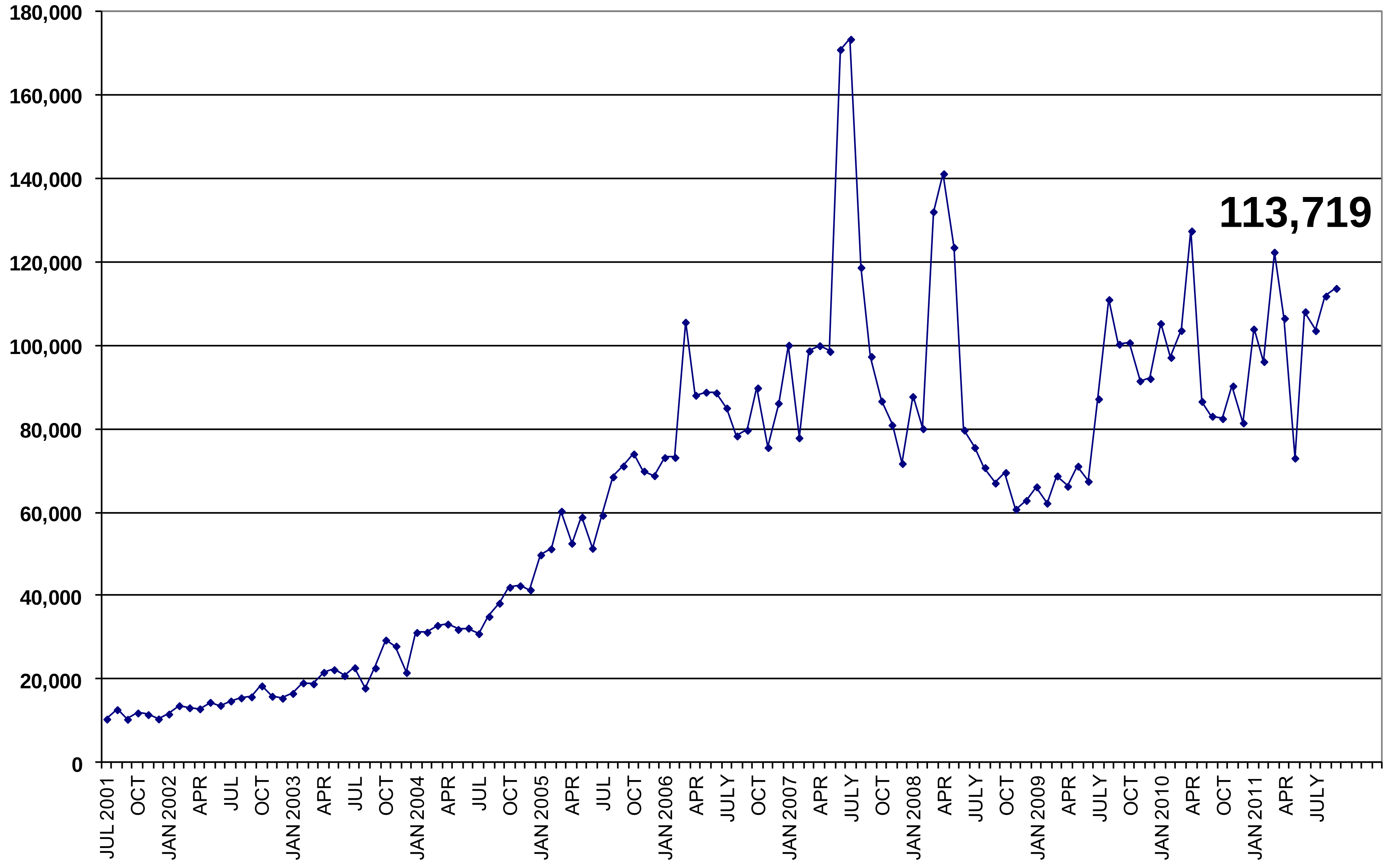


COLORADO OIL AND GAS 2011 DRILLING PERMITS BY COUNTY

as of 11-07-11



COLORADO MONTHLY COGCC WEBSITE VISITS
10-07-11



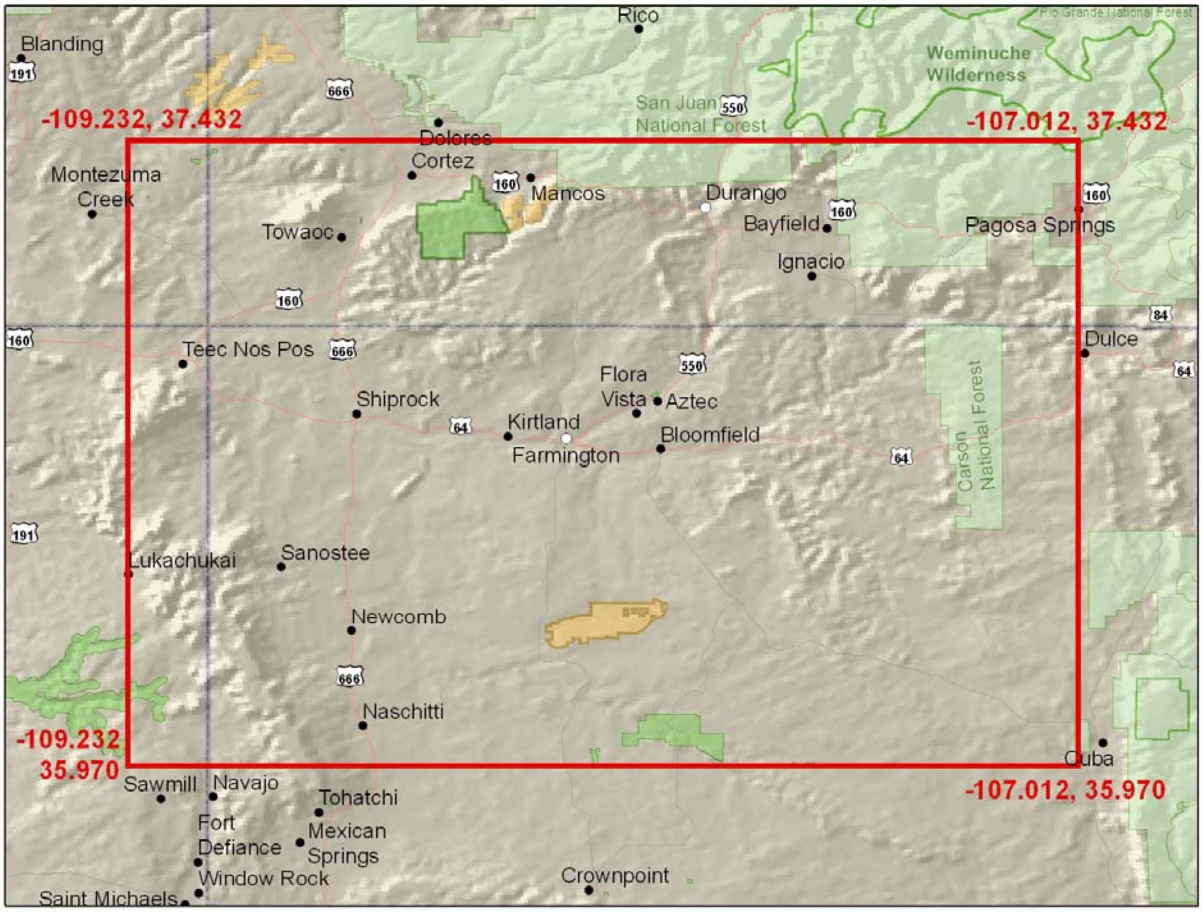
Colorado Oil & Gas Conservation Commission Statutory Requirements

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

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

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

Four Corners Air Quality Task Force
Report of Mitigation Options



November 1, 2007

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

Four Corners Air Quality Task Force Members List

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

Erik Aaboe	New Mexico Environment Department	Santa Fe, NM
Zachariah Adelman	Carolina Environmental Program	Chapel Hill, NC
Scott Archer	USDI Bureau of Land Management	Denver, CO
Roger Armstrong	Twin Stars Ltd.	Farmington, NM
Mary Lou Asbury	League of Women Voters (Cortez, Montezuma)	Cortez, CO
Cindy Beeler	US Environmental Protection Agency, Region 8	Denver, CO
Brittany Benko	BP America	Durango, CO
Andy Berger	New Mexico Environment Department	Santa Fe, NM
Bruce Beynon	Chevron	Houston, TX
Michael Brand	Cummins	Columbus, IN
Kevin Briggs	Colorado Dept. of Public Health & Environment	Denver, CO
David Brown	BP America	Denver, CO
Marilyn Brown	League of Women Voters of La Plata County	Durango, CO
Walt Brown	US Forest Service/BLM	Durango, CO
Fran King Brown	AKA Energy Group, LLC (SUIT)	Durango, CO
Greg Crabtree	Envirotech, Inc.	Farmington, NM
Jim Cue	Caterpillar, Inc.	Houston, TX
Mark Dalton	Samson Resources Company	Tulsa, OK
Carl Daly	US Environmental Protection Agency, Region 8	Denver, CO
Chris Dann	Colorado Dept. of Public Health & Environment	Denver, CO
Joseph Delwiche	US Environmental Protection Agency, Region 8	Denver, CO
Kris Dixon	Concerned Citizen	Farmington, NM
Ryan Dupnick	Compliance Controls, LLC	Houston, TX
Mike Eisenfeld	Tetra Tech Inc. / San Juan Citizens Alliance	Farmington, NM
Mike Farley	Public Service Company of New Mexico	Albuquerque, NM
Joel Farrell	USDI Bureau of Land Management	Farmington, NM
Kerri Fieldler	US Environmental Protection Agency, Region 8	Denver, CO
Patrick Flynn	Resolute Natural Resources Company	Denver, CO
Erich Fowler	Denver University	Denver, CO
Bruce Gantner	ConocoPhillips	Farmington, NM
Mike George	National Park Service	Austin, TX
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Interested Parties were those individuals who followed the progress of the Task Force, and who may have attended one or more quarterly meetings, may have participated in work groups and may have provided comments on sections of the Task Force Report.

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Background and Purpose

Overview

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

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

Air Quality Background

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

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

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

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

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

Four Corners Air Quality Task Force

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

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

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

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

The Task Force Process

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

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

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

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

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

The Task Force Report

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

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

The Path Forward

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

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

Conclusion

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

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

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Oil and Gas

Oil and Gas: Preface

Overview

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

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

Organization

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

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

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

ENGINES: STATIONARY RICE

Mitigation Option: Industry Collaboration

I. Description of the mitigation option

Overview

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

Air Quality and Environmental Benefits

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

Economic

New Engines:

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

Existing Engines:

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

Trade-offs

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

II. Description of how to implement

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

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

III. Feasibility of the option

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

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

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

IV. Background data and assumptions used

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

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

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

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

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

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

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

Mitigation Option: Install Electric Compression

I. Description of the mitigation option

Overview

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

Air Quality/Environmental

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

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

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

Economics

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

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

<u>Tradeoffs</u>

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

Burdens

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

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

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

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

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

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

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

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

IV. Background data and assumptions used

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

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

HIGH to MEDIUM based on land accessibility (easements), electric source availability and reliability of uninterrupted supply, advancing GHG legislation/regulation, and economics.

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

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

Possibly the Cumulative Effects Group due to indirect emission increases from coal-fired plants. See also Cumulative Effects Analysis for this option for further emissions analysis.

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

I. Description of the mitigation option

Overview

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

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

Air Quality/Environmental Benefits

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

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

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

Economics

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

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

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

Tradeoffs

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

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

Burdens

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

II. Description of how to implement

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

III. Feasibility of the option

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

IV. Background data and assumptions used

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

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

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

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

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

VII. Cross-over issues to the other source groups

Mitigation Option: Optimization/Centralization

I. Description of the mitigation option

Overview

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

Air Quality and Environmental Benefits

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

Economics

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

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

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

Tradeoffs

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

Burdens

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

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

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

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

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

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

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

- Input from engine manufacturers and engine consultants

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

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

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

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

I. Description of the mitigation option

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

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

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

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

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

Notes: [illegible]

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

II. Description of how to implement

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

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

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

III. Feasibility of the option

A. Technical: EPA has spent the past year working with engine manufacturers during its development of the CI and SI NSPS. The requirements have been shown to be technologically feasible.
B. Environmental: EPA's regulatory documents do/will provide details of the expected environmental benefits and the conclusion that this level of control is appropriate for areas not in advanced levels of non-attainment.
C. Economic: EPA's Regulatory Impact Analyses (RIA) for the two rulemakings will provide explanations of the expected costs of compliance.

IV. Background data and assumptions used

None beyond material in EPA's rulemakings.

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

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

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

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

VII. Cross-over issues to the other source groups

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

Mitigation Option: Adherence to Manufacturers' Operation and Maintenance Requirements

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

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

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

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

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

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

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

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

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

IV. Background data and assumptions used

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

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

VII. Cross-over issues to the other source groups

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

I. Description of the mitigation option

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

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

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

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

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

II. Description of how to implement

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

III. Feasibility of the option

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

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

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

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

IV. Background data and assumptions used

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

II. Description of how to implement

A. Mandatory or voluntary:

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

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

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

III. Feasibility of the option

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

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

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

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

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

IV. Background data and assumptions used

1. G. Sorge "Update on Emissions"

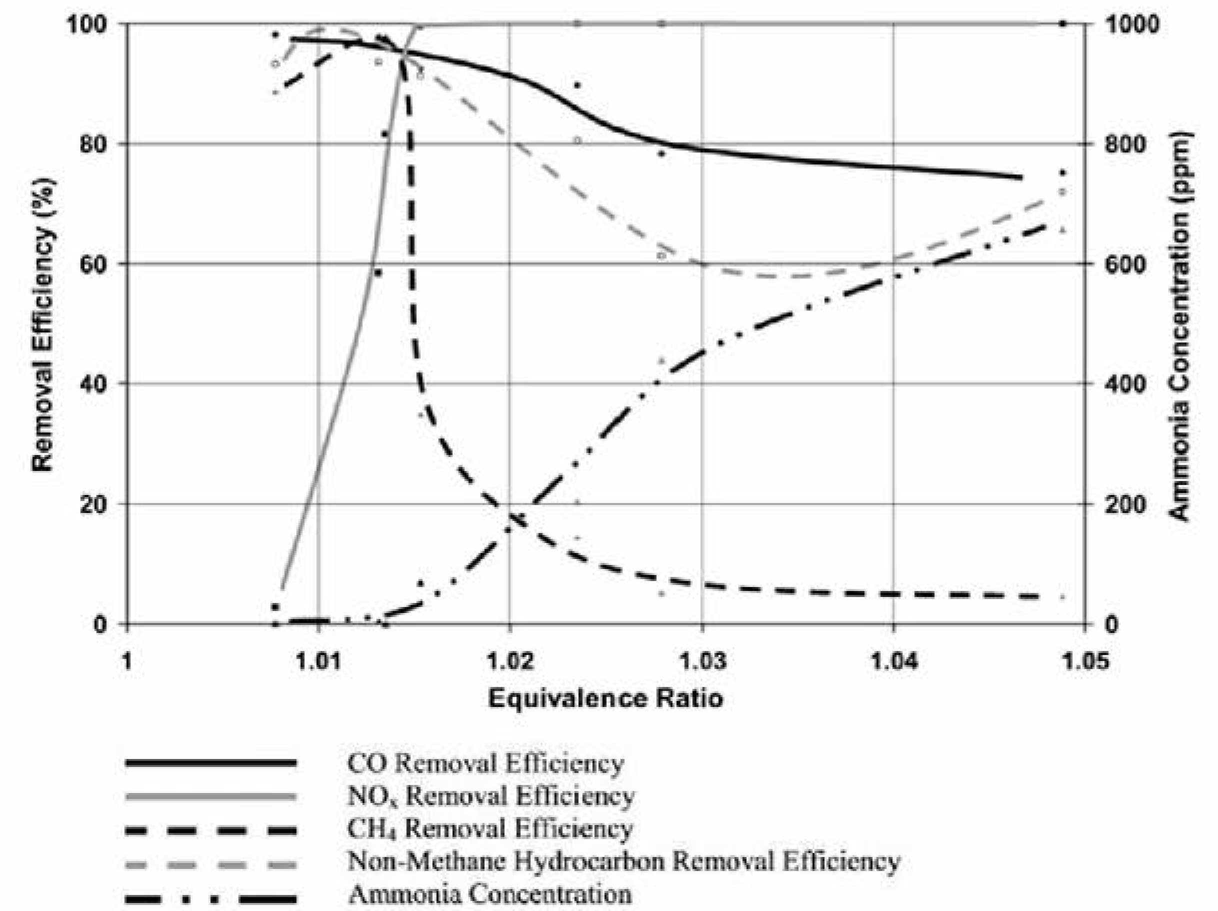
Differing opinion: Insufficient information to locate reference.

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

LOW, this is a proven technology with years of results. One issue of merit is the production of ammonia through a 3-way catalyst. This issue has been thoroughly researched and the following are the generalized results:

Differing Opinion: MEDIUM: HC is difficult to measure. Drift of control and narrow applicability to only 'true' rich burn engines are significant issues.

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



Differing opinion: Reference is needed for the Graph credentials.

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

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

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

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

I. Description of the mitigation option

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

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

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

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

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

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

II. Description of how to implement

A. Mandatory or voluntary**:**

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

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

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

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

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

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

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

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

Mitigation Option: Install Lean Burn Engines

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

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

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

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

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

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

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

IV. Background data and assumptions used
Since there are no known lean burn engines under 300 hp, engine manufacturers may be interested in developing them. The development of these engines may be the most acceptable solution to users, EPA,

and states. The forthcoming NSPS will encourage engine manufacturers to develop lean burn engines under 300 hp.

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

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

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

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

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

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

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

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

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

Mitigation Option: Interim Emissions Recommendations for Stationary RICE

I. Description of the mitigation option

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

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

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

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

- Lean burn technology is widely available from manufacturers.
- The lean burn technology will help protect visibility in the region.
- The NAAQS and PSD increments will be less affected.
- Deposition of NOx and related compounds would be reduced

  Differing Opinion: Analysis of engine quarterly flue gas testing results indicates that, on average, it is possible to achieve an emission limit of 1 g/hp-hr, however, it may not be possible to achieve this emission level on a continuous basis.

II. Description of how to implement

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

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

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

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

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

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

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

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

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

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

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

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

IV. Background data and assumptions used

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

V. Any uncertainty associated with the option

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

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

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

VII. Cross-over issues to the other source groups

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

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

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

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

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

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

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

1. Laser Ignition

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

Overview

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

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

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

Air Quality and Environmental Benefits

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

Economic

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

Trade-offs

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

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

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

II. Description of how to implement

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

III. Feasibility of the option

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

downtime for changing spark plugs.

IV. Background data and assumptions used TBD.

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

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

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

2. Air-Separation Membranes

I. Description of the mitigation option

Overview

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

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

Air Quality and Environmental Benefits

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

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

Economic

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

Trade-offs

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

II. Description of how to implement

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

III. Feasibility of the option

A. Technical: The technical feasibility of oxygen-depletion membranes has been demonstrated as an alternative to EGR. The technical feasibility of oxygen-enrichment membranes has only been shown in the laboratory for one type of engine. The technical advantages of nitrogen enrichment with membranes have been demonstrated in the laboratory for natural gas and diesel engines.
B. Environmental: The environmental benefits of oxygen-depletion membranes are the same as EGR.
C. Economic: Membrane manufacturers are presently unable to produce enough membranes for widespread implementation of the technology in truck engines. However, the oil and gas industry is a smaller market, which might allow the membrane manufacturers to ramp up their production levels. Because of this situation, the economic feasibility of air-separation membranes is difficult to assess.

IV. Background data and assumptions used

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

Published technical papers by Argonne National Laboratory and others.

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

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

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

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

3. Rich-Burn Engine with Three-Way Catalyst

I. Description of the mitigation option

Overview

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

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

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

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

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

II. Description of how to implement

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

III. Feasibility of the option

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

IV. Background data and assumptions used

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

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

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

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

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

4. Lean-Burn NOx Catalyst, Including NOx Trap

I. Description of the mitigation option

Overview

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

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

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

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

Air Quality and Environmental Benefits

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

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

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

Economic

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

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

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

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

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

I. Description of how to implement

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

II. Feasibility of the option

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

III. Background data and assumptions used

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

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

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

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

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

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

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

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

IV. Background data and assumptions used None

V. Any uncertainty associated with the option (Low, Medium, High)
NOx traps have a low uncertainty if they are used with low sulfur diesel fuel. They have a medium uncertainty when used with natural gas because of the need to reform the fuel.

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

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

VII. Cross-over issues to the other source groups

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

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

I. Description of the mitigation option

Overview

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

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

II. Description of how to implement

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

III. Feasibility of the option

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

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

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

IV. Background data and assumptions used

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

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

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

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

HCCI has high uncertainty.

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

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

Summary

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

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

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

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

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

ENGINES: MOBILE/NON-ROAD

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

I. Description of the mitigation option

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

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

II. Description of how to implement

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

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

III. Feasibility of the option

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

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

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

IV. Background data and assumptions used

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

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

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

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

Mitigation Option: Use Produced Water for Dust Reduction

I. Description of the mitigation option

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

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

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

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

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

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

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

* ND is non-detected

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

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

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

II. Description of how to implement

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

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

III. Feasibility of option

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

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

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

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

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

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

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

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

IV. Background data and assumptions used

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

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

Medium uncertainty to environment (water quality and vegetation).

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

All members of drafting team support this option.

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

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

Mitigation Option: Pave Roads to Mitigate Dust

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

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

II. Description of how to implement
A. Mandatory or voluntary: The construction and road base preparation necessary to properly pave a road would be voluntary
B. Indicate the most appropriate agency(ies) to implement: Industry, OCD, BLM, FS, County, State.

III. Feasibility of option
A. Technical: This option is technically feasible but not practical to pave all roads. Consideration needs to be given to highly travel collector roads and road near heavily populated areas. Portions of heavily travel roads could be considered for paving.
B. Environmental: Would reduce long term dust emissions from vehicle traffic throughout the San Juan Basin but there would be some shorter term increases in emissions associated with asphalt production, paving, and the construction equipment paving the road itself. However, increase accidents and speeding could be drawbacks. Additional law enforcement would be required or re-prioritized workload to curtail speeding.
C. Economic: The cost to prepare, pave, and maintain roads throughout the San Juan Basin are not practical on all roads. Furthermore, the cost to reclaim “paved roads” as part of the restoration process upon well abandonment would be substantial. Consideration could be give to paving only portions of main collector roads, especially in populated areas with heavy traffic.

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

V. Any uncertainty associated with the option (Low, Medium, High)
High, due to cost and feasibility.

VI. Level of agreement within the work group for this mitigation option.
Members agree that this option has some merit but in limited areas. Not practical to consider the entire San Juan Basin.

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

Mitigation Option: Automation of Wells to Reduce Truck Traffic

I. Description of the mitigation option

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

II. Description of how to implement

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

III. Feasibility of the option

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

IV. Background data and assumptions used

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

V. Any uncertainty associated with the option

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

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

Subgroup is in agreement with this option.

Cross-over issues to the other source groups

None at this time.

Mitigation Option: Reduced Vehicular Dust Production by Enforcing Speed Limits

I. Description of the mitigation option

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

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

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

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

II. Description of how to implement

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

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

III. Feasibility of the option

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

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

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

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

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

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

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

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

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

I. Description of the mitigation option

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

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

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

II. Description of how to implement

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

III. Feasibility of the option

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

IV. Background data and assumptions used:

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

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

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

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

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

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

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

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

III. Feasibility of the option
Technical – The technology exists today to implement this mitigation option.

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

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

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

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

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

VII. Cross-over issues to the other source groups (please describe the issue and which groups
It is believed that this issue may cross-over to the Other Sources work group.

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

I. Description of the mitigation option

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

II. Description of how to implement

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

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

III. Feasibility of the option

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

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

Economic – Implementation of this technology should be economically feasible.

IV. Background data and assumptions used

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

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

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

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

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

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

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

I. Description of the mitigation option

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

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

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

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

II. Description of how to implement

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

III. Feasibility of the option

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

IV. Background data and assumptions used

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

V. Any uncertainty associated with the option High.

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

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

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

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

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

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

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

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

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

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

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

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

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

VII. Cross-over issues to other source groups

Mitigation Option: Exhaust Engine Testing for Combustion Engine Emission Controls

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

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

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

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

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

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

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

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

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

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

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

Mitigation Option: Reduce Trucking Traffic in the Four Corners Region

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

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

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

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

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

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

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

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

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

ENGINES: RIG ENGINES

Mitigation Option: Diesel Fuel Emulsions

I. Description of the mitigation option

Diesel Fuel Emulsions:

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

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

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

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

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

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

II. Description of how to implement

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

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

III. Feasibility of the option

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

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

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

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

IV. Background data and assumptions used

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

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

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

Low uncertainty as this is a verified, simple retrofit.

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

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

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

None at this time.

Mitigation Option: Natural Gas Fired Rig Engines

I. Description of the mitigation option

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

Benefits

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

Tradeoffs

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

Burdens

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

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

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

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

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

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

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

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

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

VII. Cross-over issues to other source groups

Mitigation Option: Selective Catalytic Reduction (SCR)

I. Description of the mitigation option

Selective Catalytic Reduction (SCR)

Description

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

Benefits

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

Tradeoffs

- Ammonia Slip

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

Burdens

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

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

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

II. Description of how to implement

A. Mandatory or voluntary: The workgroup believes that more information is required on the contribution of rig emissions to the total NOx emissions and the potential ammonia emissions impact to visibility prior to determining whether this mitigation should be mandatory or voluntary.

.

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

III. Feasibility of the option

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

IV. Background data and assumptions used

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

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

Medium – It is clear that SCR is effective in reducing NOx emissions, however an understanding of the potential increase of ammonia emissions and the resulting impacts to visibility need to be understood.

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

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

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

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

Mitigation Option: Selective Non-Catalytic Reduction (SNCR)

I. Description of the mitigation option

Selective Non-Catalytic Reduction (SNCR) is a post-combustion treatment in which ammonia is injected into the flue gas stream. The ammonia reacts with the NOx compounds, forming nitrogen and water. In order for this technique to be effective, the ammonia must be injected at a proper temperature range within the stack and must be in the proper ratio to the amount of NOx present. The reduction reaction at temperatures ranging from 925 – 1125ºC does not require catalysis and can achieve 40% NOx control. More modest NOx reductions are reported in the 725 - 925ºC range.

Differing Opinion: These are very high temperatures and much greater than the temperatures in diesel engine exhaust. For example, the data sheet for a Cat 3512 diesel rig engine shows a "highest" exhaust temperature of ~792 degrees F. Based on the degradation in performance reported in the 725 – 925 degrees C it probably would have very little effect at the exhaust temperatures from rig engines. This technology is really tested for very high temperature boilers only – not engines.

Benefits

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

Tradeoffs

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

Burdens

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

II. Description of how to implement

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

III. Feasibility of the option

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

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

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

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

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

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

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

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

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

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

The pertinent regulations are as follows:

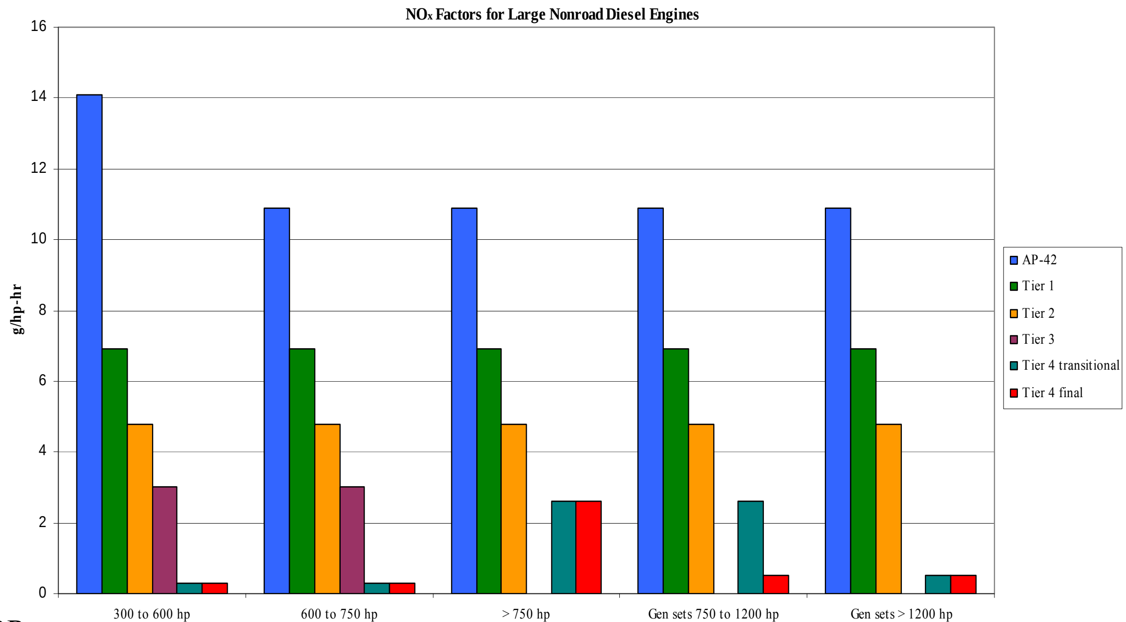
Clean Air Nonroad Diesel - Tier 4 Final Rule: Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel, 69 FR 38957, June 29, 2004

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

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

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

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



OR

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

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

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

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

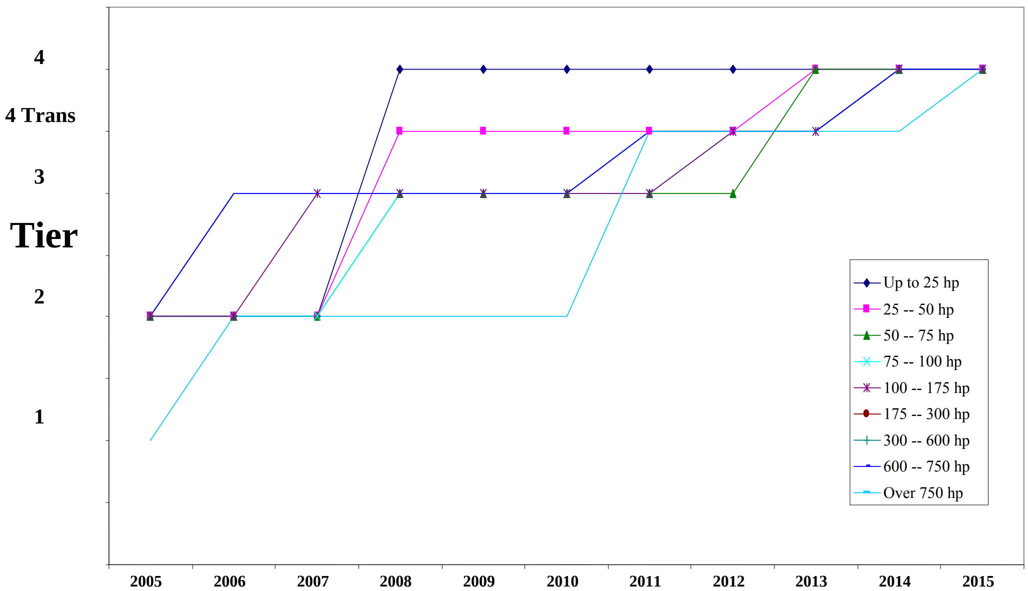


Table 1. Nonroad CI Engine Emission Standards[a]

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

4

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

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

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II. Description of how to implement

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

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

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

III. Feasibility of the option

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Mitigation Option: Interim Emissions Recommendations for Drill Rigs

I. Description of the mitigation option

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

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

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

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

II. Description of how to implement

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

III. Feasibility of the Option

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

IV. Background data and assumptions used

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

V. Any uncertainty associated with the option

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

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

TBD.

VII. Cross-over issues to the other source groups

None.

Mitigation Options: Various Diesel Controls

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

I. Description of the mitigation options

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

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

Biodiesel

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

PM Traps

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

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

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

Free Gas Recirculation

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

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

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

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

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

Exhaust Gas Recirculation (EGR)

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

II. Description of how to implement

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

III. Feasibility of the option

A. Technical
B. Environmental
C. Economic

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

IV. Background data and assumptions used

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

V. Any uncertainty associated with the option

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

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

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

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

ENGINES: TURBINES

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

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

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

Differing Opinion: The best technology should be mandatory.

B. Indicate the most appropriate agency(ies) to implement Federal, state, and tribal agencies responsible for air emissions compliance.

III. Feasibility of the option
A. Technical Individual turbine assessment will be needed to confirm appropriate size or design limitations (not all turbines can be retrofitted).
B. Environmental The benefits of a dry LoNOx emissions control technology on air emissions has been proven repeatedly for many large turbines.
C. Economic The economic impact cannot be understood without an inventory of installed turbines.

IV. Background data and assumptions used
No assumptions have been made at this time on the impact of emissions reductions due to the uncertainty of the existing turbine population.

V. Any uncertainty associated with the option High.

VI. Level of agreement within the work group for this mitigation option High.

VII. Cross-over issues to the other source groups
The impact of implementing this option may be further evaluated by the Cumulative Effects or Monitoring groups.

EXPLORATION & PRODUCTION: TANKS

Mitigation Option: Best Management Practices (BMPs) for Operating Tank Batteries

I. Description of the mitigation option
This option involves implementing and/or adoption of various Best Management Practices (BMPs) for operating tanks that contain crude oil and condensate. The specific BMPs include the use of Enardo valves, closing thief and other tank hatches, maintaining valves in leak-free condition, closing valves, etc. so as to minimize VOC losses to the atmosphere.

Economic burdens are minimal since these practices are largely followed and considered a normal cost of doing business as part of responsible operations.

There should not be any environmental justice issues associated with following these practices in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement
A. Mandatory or voluntary: The implementation of measures to implement BMPs for operating tank batteries are envisioned as "voluntary" measures to enhance operating efficiency and could be easily incorporated as a BMP in voluntary programs such as the NMED San Juan VISTAS program and EPA's Natural Gas STAR Program. There are currently no mechanisms or rules to require BMPs as standards, and this seems implausible as a mandatory approach. Many companies have BMPs in place already.

B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option
A. Technical: The use of BMPs for operating tank batteries is technically feasible as is software to maximize routing efficiency.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented.
Differing opinion: Quantification of emission reductions from implementation of this mitigation option is not possible.
C. Economic: These BMPs need to be explored by individual companies as to their economic viability.

IV. Background data and assumptions used
1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. Oil and gas producing companies will need to educate their workforce on the validity and importance of these BMPs.
3. Employees will not react adversely to following these practices as a normal course of being a lease operator.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option
General agreement within working group members that this is viable and probable.

Mitigation Option: Installing Vapor Recovery Units (VRU)

I. Description of the mitigation option

This option involves using Vapor Recover Units (VRUs) on crude oil and condensate tanks so as to capture the flash emissions that result when crude oil or condensate is dumped into the tank from the production separator. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient flash gas were present, there would be economic benefits as well.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement VRUs for operating tank batteries are envisioned as "voluntary" measures since the feasibility of VRUs in the Four Corners area is negative. In certain areas of the country where ozone non-attainment areas exist, VRUs are commonly mandated by the respective Air Quality Control agency as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). Since the Four Corners area is not in ozone non-attainment and the costs economics will not generally justify installation of VRUs for economic benefit, a voluntary approach is recommended.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option

A. Technical: The use of VRUs for operating tank batteries is technically feasible.
Differing opinion: However, installation of a VRU to most existing tank installations is not likely feasible without a complete redesign and new installation. Most tanks are pressure rated at 3-5 psig and would need to be replaced with tanks designed with higher pressure rating to handle pressure surges during separator dumps. Additional pressure relief valving, pressure regulators and other safety devices would need to be included with these systems. Redesign and system replacement would need to be evaluated to determine the economic feasibility of this type of system. As these tanks are under pressure there would be additional operational and safety issues related to proper product transfer and handling. Most transporters are not equipped to handle pressurized product transfers at present. Due to the small amount of condensate produced in 4-Corners wells, the periodic "dumping" from the separators to the tanks, and the consequent uneven flash of gas from the condensate the use of VRU's is technically very challenging and may not be technically feasible. VRU's start from atmospheric pressure and boost gas to low pressure that may not be sufficient to flow into the collection system lines. In this case, they are either not feasible or would require additional compression. The lack of electricity in the fields effectively precludes any operationally feasible VRU use.

B. Environmental: The environmental benefits of reduced VOC pollution are well documented. Benefits are relative to production throughputs. VOC emissions from flashing emissions are a function of well pressure and condensate production. The amount of emission reduction will be proportional to the amount of uncontrolled VOC emissions. Even if VRU's can be made to work in the 4-corners area, the amount of VOC emission reduction per tank will be low due to the low condensate production rate.

C. Economic: The use of VRUs for recovering the flash emissions from produced crude oil/condensate are economically feasible where the Gas Oil Ratio (GOR) from produced crude oil/condensate is high and the daily production volume is at least 50 barrels/day or greater. Most wells in the Four Corners area typically produce less than 1 bbl/day of crude oil or condensate so VRUs are not economically feasible.

Flares or combustors could be considered an alternative control technology if sufficient VOC emissions exist. At 1 bbl/day and low pressure drop the flash gas volume and VOC content will not justify control systems.

IV. Background data and assumptions used

1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. The minimal production levels for most wells make the use of VRU economically infeasible.

V. Any uncertainty associated with the option

Low.

Differing opinion: MEDIUM based on availability of power, high maintenance requirements and reliability/performance.

Differing opinion: This would rank a high level of uncertainty in actually achieving meaningful and cost effective emission reductions using this technology.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that the use of VRUs in the Four Corners areas is economically infeasible and an unlikely source for voluntary adoption.

Mitigation Option: Installing Gas Blankets Capability

I. Description of the mitigation option
This option involves modifying existing and installing new designed crude oil and condensate tanks that would be capable of placing an inert gas blanket over these tanks to minimize vapor loss. The inert gas would fill the space above the condensate/crude oil to minimize volatilization and vapor loss. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient flash gas if present, there would be economic benefits as well.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement
A. Mandatory or voluntary: The implementation of measures to implement gas blankets for operating tank batteries are envisioned as "voluntary" measures since the feasibility of gas blanket technology in the Four Corners area is negative. In certain areas of the country where ozone non-attainment areas exist, gas blanket technology is one of several measures commonly mandated by the respective Air Quality Control agency as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). Since the Four Corners area is not in ozone non-attainment and the cost economics will not generally justify installation of gas blankets for economic benefit, a voluntary approach is recommended.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option
A. Technical: The use of gas blankets for operating tank batteries is technically feasible but requires the tanks to be designed to handle the increased pressures that will result when crude oil/condensate enters the tank, thereby pressurizing the gas blanket. Currently crude oil/condensate tanks are designed as atmospheric tanks and are designed only to withstand 5 psig of internal pressure. API 12F specifies 16 oz of pressure for normal operation and no greater than 24 oz for emergency operations. Using gas blanket technology requires such tanks to withstand about 100 psig, which increases the costs for tanks substantially. As these tanks are under pressure there would be additional operational and safety issues related to proper product transfer and handling. Most transporters are not equipped to handle pressurized product transfers at present.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented.
Differing opinion: If this is considered a candidate control technology, the detailed engineering and economic analyses are needed to evaluate the cost to control relative to other potential control measures.
C. Economic: The use of gas blanket technology for preventing the release of flash and vapor emissions from produced crude oil/condensate are economically feasible for large, centrally located tank batteries where the crude oil/condensate can be piped from numerous wells to a centralized facility. Most wells in the Four Corners area typically produce less than 1 bbl/day of crude oil or condensate so the use of pipelines to transport the crude oil/condensate to a centralized facility is uneconomic.

IV. Background data and assumptions used
1. Individual tank batteries rather than large, centralized tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the minimal daily production volumes (i.e., less than 1 barrel/day).

V. Any uncertainty associated with the option Low.

Differing opinion: HIGH based on feasibility comments above and additional regulatory requirements for pressurized vessels, transport of pressurized product, and added safety processes.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that the use of gas blanket technology in the Four Corners areas is economically unfeasible and an unlikely source for voluntary adoption.

Mitigation Option: Installing Floating Roof Tanks on Tanks in the Four Corners Region

I. Description of the mitigation option

This option involves using floating roof tanks on crude oil and condensate tanks so as to prevent the loss of emissions that result from crude oil or condensate stored in the tank. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient gas were present, there would be minimal economic benefits. However, the use of floating roof tanks on smaller tanks instead of fixed roof tanks do not reduce the emissions. The emissions actually increase.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement floating roof tanks on tank batteries are envisioned as "voluntary" measures since the feasibility of floating roof tanks in the Four Corners area is negative. At certain facilities in the country where tanks are considerably larger are commonly mandated by the respective Air Quality Control agency as BACT or LAER. The common sizes of tanks in the Four Corners area will not benefit economically or in emission reductions through installation of floating roof tanks. Generally, emissions will increase if floating roofs are installed on these small tanks. Therefore, this mitigation does not have merit for the Four Corners area and is recommended not to be implemented either voluntary or mandatory.
B. Indicate the most appropriate agency (ies) to implement**:** NMED, Colorado Air Pollution Control Division.

III. Feasibility of the option

A. Technical: The use of floating roof tanks on tank batteries is technically feasible, however, not currently available for smaller sized tanks.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented for larger tanks; however the documentation on smaller tanks with fixed roofs indicates an increase in emissions.
C. Economic: The use of floating tank roofs for preventing the working loss emissions from produced crude oil/condensate is not economically feasible.

IV. Background data and assumptions used

1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. The minimal production levels for most wells make the use of floating rank roofs economically infeasible.

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option.

General agreement within working group members is that the use of floating tank roofs in the Four Corners areas is economically infeasible and an unlikely source for voluntary adoption.

EXPLORATION & PRODUCTION: DEHYDRATORS/SEPARATORS/HEATERS

Mitigation Option: Replace Glycol Dehydrators with Desiccant Dehydrators

I. Description of the mitigation option

Desiccant dehydrators utilize moisture-absorbing salts to remove water from natural gas. Desiccants can be a cost-effective alternative to glycol dehydrators. Additionally, there are only minor air emissions from desiccant systems.

Desiccant dehydrators are very simple systems. Wet gas passes through a "drying" bed of desiccant tablets (e.g., salts such as calcium, potassium or lithium chlorides). The tablets pull moisture from the gas, and gradually dissolve to form a brine solution. Maintenance is minimal - the brine must be periodically drained to a storage tank, and the desiccant vessel must be refilled from time to time. Often, operators will utilize two vessels so that one can be used to dry the gas when the other is being refilled with salt.

Desiccant dehydrators have the benefit of greatly reducing air emissions. Conventional glycol dehydrators continuously release methane, volatile organic compounds (VOC) and hazardous air pollutants (HAP) from reboiler vents; methane from pneumatic controllers; CO_2 from reboiler fuel; and CO_2 from wet gas heaters. The only air emissions from desiccant systems occur when the desiccant-holding vessel is depressurized and re-filled – typically, one vessel volume per week.[1] Some operators have experienced a 99% decrease in CH_4/VOC/HAP emissions when switching over to a desiccant system.[2]

Other potential benefits of desiccant dehydrators include: reduced ground contamination; reduced fire hazard; low maintenance requirements (because there are no moveable parts to be replaced and maintained); and the elimination of an external power supply.[3]

Solid desiccants are commonly used at centralized natural gas plants, but glycol dehydrators are still the most popular form of dehydration used in the field.[4] Most probably this is because there are particular conditions under which desiccant dehydrators work best:

- **The volume of gas to be dried is 5 MMcf/day or less.** Many wells in the San Juan Basin average less than 5 MMcf/day,[5] so this should not be a constraint to using desiccant systems.
- **Wellhead gas temperature is low (< 59º F for CaCl and < 70º for LiCl)**. If the inlet temperature of the gas is too high, desiccants can form hydrates that precipitate from the solution and cause caking and brine drainage problems. It is possible to cool or compress gas to the appropriate temperatures, but this increases the cost of the desiccant system.
- **Wellhead gas pressure is high (> 250 psig for CaCl and >100 psig for LiCl).**

II. Description of how to implement

A. Mandatory or voluntary

Where feasible, it should be mandatory, since it is both cost effective and virtually eliminates air emissions from field dehydrators.

Differing opinion: Cost is prohibitive for replacement of existing systems but applicable for new installations as determined on a case-by-case evaluation.

B. Indicate the most appropriate agency(ies) to implement

Dehydration is not a down-hole issue, therefore, is not the sole purview of the oil and gas commissions. Furthermore, this option relates specifically to minimizing air emissions. Thus, the most appropriate agencies to implement this option would be the environment/health agencies in the different states.

Differing opinion: The Federal area source MACT rules address glycol dehydrators and require controls for those whose size and throughputs justify control. This regulation was carefully considered and evaluated by EPA prior to finalization and should not be exceeded without careful analysis and justification.

III. Feasibility of the option

A. Technical

Desiccant dehydration is currently feasible under certain operating conditions (i.e., temperature and pressure of inlet gas). It may be possible to expand the applicability with add-on technologies (e.g., auto-refrigeration units to chill the inlet gas).[6]

Differing opinion: On March 20, 2007 at the NMOCD Greenhouse Gas meeting held in Santa Fe, NM, an operator stated during his presentation that based on their company's experience with salt dehydration in Wyoming, they are removing all salt dehydrators from service. Although the economics and technical feasibility initially looked very favorable, they have found salt slippage and other operational concerns very problematic with no technical solutions to date. Thus this method of dehydration is currently not as viable for their operations. This technology needs to be thoroughly considered before adoption – although it looks good initially, long-term use has not proven to be sustainable.

B. Environmental

Under some environmental conditions (e.g., high temperatures) this option becomes less feasible. Wastewater by product would need to handled, disposed of or re-injected. In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

C. Economic

For new dehydration systems, desiccant systems have been shown to be a lower cost alternative (both for capital and operating costs) than glycol dehydrators.[7] The payback period to replace an existing glycol dehydrator with a desiccant system has been shown to be less than 3 years.[8] The economics stated are only valid for a small range of temperature, pressure, and water content combinations. Desiccant dehydration for hot, low pressure, or high water content gas streams is not cost effective when compared to glycol dehydration.

Differing opinion: Increased operational costs for the desiccant, storage, and handling/disposal of wastewater should be factored in to the economics.

IV. Background data and assumptions used See endnotes.

V. Any uncertainty associated with the option Low.

Differing opinion: MEDIUM-HIGH based above comments regarding generation of wastewater, disposal, and recent operational experiences in Wyoming.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other Task Force work groups

Notes:

1. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 5. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf

2. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 1. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
3. Acor, L. Design Enhancements to Eliminate Sump Recrystalization in Zero-Emissions Non-Regenerative Desiccant Dryer. In: The Tenth International Petroleum Environmental Conference, Houston, TX. November 11-14, 2003 http://ipec.utulsa.edu/Conf2003/Papers/acor_78.pdf
4. Smith, Glenda, American Petroleum Institute, written comments to Dan Chadwick, USEPA/OECA, September 22, 1999. In. EPA Office of Compliance. Oct. 2000. Sector Notebook Project - Profile of the Oil and Gas Extraction Industry. EPA/310-R-99-006. p. 31
5. Lippman Consulting. May 16, 2005. "Production levels increase in San Juan Basin," Energy Quarterly. http://www.businessjournals.com/ artman/publish/article_898.shtml
6. U.S. EPA. Natural Gas Star. Replace Glycol Dehydrator with Separators and In-Line Heaters. PRO Fact Sheet No. 204.
   http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/replaceglycoldehydratorwithseparators.pdf
   Auto-refrigeration has been used in other oilfield applications, such as chilling gas to enhance water condensation and separation.
7. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 16. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
   For a system processing 1 MMcf/day natural gas, operating at 450 psig and 47 F:
   Total implementation (capital plus installation): $22,750 (desiccant) vs. $35,000 (glycol)
   Total annual operating costs: $3,633 (desiccant) vs. $4,847 (glycol)
8. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 17. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
   This payback period was reported for a glycol dehydrator system that was replaced with a two-vessel desiccant dehydration system.

Mitigation Option: Installation of Insulation on Separators

I. Description of the mitigation option
This option involves modifying existing and installing new separators that are insulated so as to reduce fuel usage. The air quality benefits would be to minimize combustion emissions to the atmosphere (NOx, CO, NMHC).

Economic burdens are significant but not insurmountable if the cost recovery factor from reduced fuel usage over the anticipated life of the unit shows a positive return on investment.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement
A. Mandatory or voluntary: The implementation of measures to implement insulated separators and vessels are envisioned as "voluntary" measures since the feasibility of installing insulation on new units or retrofitting existing units must be evaluated for a positive Net Present Value (NPV) or Return on Investment (ROI) in the Four Corners area. If the NPV or ROI meets a company's investment targets, then utilization of this technology should be encouraged as a best practice. There are no existing mandates by the respective Air Quality Control agencies to require insulated vessels as BACT. Since the Four Corners area is not in ozone non-attainment and the cost economics will not always justify installation of insulation for economic benefit, a voluntary approach is recommended.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option
A. Technical: The application of insulation to separators, tanks, or other heated vessels is technically feasible. Currently some companies are insulating newly installed on production separators and larger produced water tanks on a case-by-case basis.
B. Environmental: The environmental benefits of reduced NOx, CO, and NMHC pollution are well documented.
Differing opinion: It is unclear how much insulation would cut fuel consumption and consequently reduce emissions. The emissions from well-site production units are very small (the units are very small) and not a significant component of the regional NOx budget. Insulation of these units would make a small reduction in a very small number.
C. Economic: The application of insulation to separators, tanks, or other heated vessels for reducing fuel usage and minimizing combustion emissions from separators, tanks, or other heated vessels are economically feasible where the there is payback that meets the respective companies targets for investments (i.e., ROI or NPV). For older units or vessels where the remaining life of the equipment is limited, the economics may not justify the application of insulation. Costs basis and frequency of maintenance and ultimate replacement of both blown and wrapped insulation should be identified.

IV. Background data and assumptions used
Most fired units in the Four Corners area are utilized during the time period from November through March to achieve their objective.

V. Any uncertainty associated with the option (Low, Medium, High) Low.
Differing opinion: High in terms of emission reductions.

VI. Level of agreement within the work group for this mitigation option TBD.

Mitigation Option: Portable Desiccant Dehydrators

I. Description of the mitigation option

Desiccant dehydrators utilize moisture-absorbing salts (e.g., calcium, potassium or lithium chlorides) to remove the water from natural gas.

Glycol dehydrators may be more suitable than desiccant systems in some field gas dehydration situations (e.g., when inlet gas has a high temperature and low pressure). But glycol dehydrators require regulator maintenance for optimal performance. During maintenance periods production wells are either shut-in or vented to the atmosphere (rather than running wet gas into the pipeline). Venting is especially popular for low-pressure wells, because it can be difficult to resume gas flow once they are shut in.

Portable desiccant dehydrators can be brought on-site during glycol dehydrator maintenance (or break-down) periods. This allows the gas to be processed and sent to the pipeline, rather than requiring the well to be shut-in, or the gas to be vented. These portable dehydrators can also be used to capture and dehydrate gas during "green completion" operations.

The benefits of utilizing portable desiccant dehydrators are: the ability to continue producing a well during glycol dehydrator maintenance; the elimination of methane, VOCs and HAPs that would otherwise be vented while glycol dehydrators are being serviced.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary at this point in time. There are technologies that would result in much more significant air emissions reductions that should have higher regulatory priority.

Differing opinion: On March 20, 2007 at the NMOCD Greenhouse Gas meeting held in Santa Fe, NM, an operator stated during his presentation that based on their company's experience with salt dehydration in Wyoming, they are removing all salt dehydrators from service. Although the economics and technical feasibility initially looked very favorable, they have found salt slippage and other operational concerns very problematic with no technical solutions to date. Thus this method of dehydration is currently not as viable for their operations.

B. Indicate the most appropriate agency(ies) to implement

Environment/Health Departments, which have the responsibility for the regulation of air quality.

III. Feasibility of the option

A. Technical

A portable desiccant dehydrator requires a truck that has been modified to house the dehydrator; and ancillary equipment (e.g., piping) to re-route gas flow from the glycol to the desiccant dehydrator. See the discussion of technical feasibility in the desiccant dehydration option paper – the same comments and issues apply here.

B. Environmental

Desiccant dehydration systems work best under certain gas temperature and pressure conditions. Wastewater by product would need to handled, disposed of or re-injected. In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry gas and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

C. Economic

Capital cost of a 10-inch portable desiccant dehydrator is estimated to be greater than $4,000. Operating costs (e.g., labor, transportation, set-up and decommissioning) are on the order of $5,000/yr.

Differing opinion: Cost is prohibitive for replacement of existing systems but applicable for new installations as determined on a case-by-case evaluation. Increased operational costs for the desiccant, storage, and handling/disposal of wastewater should be factored in to the economics.

One operator reports that portable desiccant dehydrators are economical when used on gas wells that produced more than 15.6 Mcf/day.

Obviously, a company would get the most economic benefit from owning this equipment if the equipment was kept in continual operation – i.e., moved from one site immediately to another.

IV. Background data and assumptions used
All information in this mitigation option comes from: U.S. EPA. *Portable Desiccant Dehydrators.* PRO Fact Sheet No. 207. Available at: http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/portabledehy.pdf

V. Any uncertainty associated with the option TBD.
Differing opinion: MEDIUM-HIGH based above comments regarding generation of wastewater, disposal, and recent operational experiences in Wyoming.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None at this time.

Mitigation Option: Zero Emissions (a.k.a. Quantum Leap) Dehydrator

I. Description of the mitigation option

Conventional glycol dehydrators route natural gas through a contactor vessel containing glycol, which absorbs water (and VOCs, HAPs) from the gas. Typically, gas-driven pumps are then used to circulate glycol through a reboiler/stripper column, where it is regenerated, then sent back to the contactor vessel. Distillation and reboiling removes VOCs, HAPs and absorbed water from the glycol, and releases these compounds through the "still column" vent as vapor. Conventional glycol dehydrators vent directly to the atmosphere. Add-on technologies, such as thermal oxidizers, can reduce the amount of methane and VOCs that are vented, but result in increased NO_x, particulate matter and CO emissions.[1]

Natural gas dehydration is the third largest source of methane emissions and causes more than 80% of the natural gas industry's annual HAP and VOC emissions.[2] In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry gas and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

The zero emissions dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent.

- Rather than being released as vapor, the water and hydrocarbons are collected from the glycol still column, and the condensable and non-condensable components are separated from each other. The two primary condensable products are wastewater, which can be disposed of with treatment; and hydrocarbon condensate, which can be sold. The non-condensable products (methane and ethane) are used as fuel for the glycol reboiler, instead of releasing them to the atmosphere.
- A water exhauster is used to produce high glycol concentrations without the use of a gas stripper.
- Methane emissions are further reduced by using electric instead of gas-driven glycol circulation pumps.

Benefits of this technology include:

- Elimination of methane emissions.[3]
- Elimination of virtually all VOCs (reduction from multiple tons per year to pounds per year.[4]
- Has a HAP destruction efficiency of greater than 99%.[5]
- Reduces emissions of particulate matter, sulfur dioxide, NO_x or CO emissions (these compounds are emitted when thermal oxidation, a competing method of reducing glycol dehydrator VOC emissions, is used).
- Eliminates the Kimray pump, which is typically used to circulate glycol. Kimray pumps require extra gas (which is eventually vented to the atmosphere) for pump power.[6]
    - Significantly reduces fuel requirements for glycol reboiler. Natural gas that was used for this purpose can now be sent to market.
    - Results in collection of condensate, which can be sold.

II. Description of how to implement

A. Mandatory or voluntary

The zero emissions dehydrator system offers incredible reductions in emissions. States that are experiencing air quality problems could make this a mandatory technology, and achieve large reductions in VOC, HAP and methane emissions.

Differing opinion: Previous statement requires supporting documentation and quantification of 'trade-off' pollutants.
B. Indicate the most appropriate agency(ies) to implement
Dehydration is not a down-hole issue, therefore, is not the sole purview of the oil and gas commissions. Furthermore, this option relates specifically to minimizing air emissions. Thus, the most appropriate agencies to implement this option would be the environment/health agencies in the different states.

III. Feasibility of the option
A. Technical
The operation of the glycol circulation pump requires electric utilities or an engine generator set. The use of electric pumps (rather than fossil fuel driven pumps) will minimize NO_x, CO, CO_2, SO_2 emissions at the wellhead, but will result in some emissions at electrical generation source (e.g., coal-fired power plant).

Zero emissions dehydrators can be newly installed, and existing dehydrators can be retrofitted by modifying the gas stream piping and using a 5 kW engine-generator for electricity needs.[7] This requires a fuel or power source, for which associated emissions need to be quantified.

B. Environmental
Environmental benefit for this mitigation option needs to be defined.

C. Economic[8]
Capital costs of a zero emissions dehydrator are similar to the costs of installing a conventional dehydrator equipped with a thermal oxidizer (>$10,000). Operating and Maintenance costs are greater than $1,000 per year, but lower than the maintenance costs for conventional glycol dehydrators.

If operators were to install zero emissions dehydrators, EPA estimates that the payback to occur in less than a year.
Differing opinion: This presumes the ability to recover the hydrocarbons for sales – which is not without significant challenges and technical difficulties.

IV. Background data and assumptions used

The calculations of methane, VOC and HAP emissions from the zero emissions dehydrator were based on a dehydrator that processed 28 MMcf/day.[9] Other assumptions are contained in the endnotes.

If we had emissions data for glycol dehydrators from the San Juan Basin, we could provide a more accurate (and basin-specific) comparison of methane, VOC and HAP emissions from conventional dehydrators versus emissions from zero emissions dehydrators.

V. Any uncertainty associated with the option TBD.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None at this time.

Notes:
1. Permit renewal application by Centerpoint Energy Gas Transmission Co. to Louisiana Department of Environmental Quality. AI# 26802. March, 2005. Available at: http://www.deq.louisiana.gov/apps/pubNotice/show.asp?qPostID=2335&SearchText=centerpoint&startDate=1/1/2005&endDate=7/6/2006&category=

The application includes estimated emissions scenarios for controlling glycol dehydrator still column vent emissions with or without thermal oxidation.

2. McKinnon, H.W. and Piccot, S.D. 2003. "Emissions control of criteria pollutants, hazardous pollutants, and greenhouse gases, Natural Gas Dehydration, Quantum Leap Dehydrator." Environmental Technology Verification Program, Joint Verification Statement. U.S. EPA and Southern Research Institute. Available at: http://www.epa.gov/etv/pdfs/vrvs/03_vs_quantum.pdf
3. *ibid.*
4. Rueter, C.O., Reif, D.L. and Myers, D.B. 1995. Glycol dehydrator BTEX and VOC emissions testing results at two units in Texas and Louisiana. U.S. EPA Air and Energy Engineering Research Laboratory. Project No. EPA/600/SR-95/046.
   A study of two glycol dehydrators, processing 3.6 and 4.9 million standard cubic feet of gas per day, were found to have VOC emissions of approximately 19 and 37 tons of VOC/year, respectively. Tests run on the Zero Emissions Dehydrator, processing 28 million standard cubic feet of gas per day, resulted in average emissions of 0.0003 lb/h (2.6 lbs/yr). This is a dramatically lower amount of VOC emissions than conventional glycol dehydrators.
5. McKinnon, H.W. and Piccot, S.D. 2003. (See Note 2)
6. Fernandez, R., Petrusak, R., Robins, D. and Zavodil, D. June, 2005. "Cost-effective methane emissions reductions for small and midsize natural gas producers," Journal of Petroleum Technology. Available at: http://www.icfi.com/Markets/Environment/doc_files/methane-emissions.pdf
7. U.S. EPA. "Zero emissions dehydrators," PRO Fact Sheet No. 206. Available at: http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/zeroemissionsdehy.pdf
8. All of the economic information comes from: U.S. EPA. (see Note 7)
9. McKinnon, H.W. and Piccot, S.D. 2003. (See Note 2)

Mitigation Option: Venting versus Flaring of Natural Gas during Well Completions

I. Description of the mitigation option

Both venting and flaring of natural gas result in the release of greenhouse gases, hazardous air pollutants (HAPs) and others.

The venting of natural gas primarily releases methane, a greenhouse gas. Depending on the composition of the gas, venting will release other hydrocarbons such as ethane, propane, butane, pentane and hexane. In some locations, natural gas contains the EPA-designated HAPs benzene, toluene, ethyl benzene and xylenes (BTEX). Both hexane (also a HAP) and the BTEX compounds are present in San Juan Basin natural gas, typically accounting for 0.3 - 0.6 % of the natural gas composition.[1]

Differing opinion: This is only true for the conventional production. Coal bed methane does not contain appreciable amounts of VOCs or HAPs. Depending on the formation, natural gas may also contain nitrogen, carbon dioxide or sulfur compounds, such as hydrogen sulfide (H_2S), which is a highly toxic gas. In the New Mexico portion of the San Juan Basin, there are at least 375 gas wells, from at least five different producing formations, that contain hydrogen sulfide.[2]

Flaring is used as a means of converting natural gas constituents into less hazardous and atmospherically reactive compounds. The main purpose for flaring is for process safety reasons. Flaring is required when completing a well for two reasons: (1) the initial gas and liquids produced by most wells does not meet the gas gatherer's (pipeline's) quality requirements, and (2) the flare is the primary safety device in the event of an overpressure or equipment failure. The objective for both industry and the public is to minimize flaring where possible for both environmental and economic reasons. The assumption is that combustion processes associated with flares efficiently converts hydrocarbons and sulfur compounds to relatively innocuous gases such as CO_2, SO_2, and H_2O.

While industrial flares associated with processes such as refineries have the potential to be highly efficient (e.g., 98-99%), the few studies that have been conducted on oil and gas "field flares" have found much lower efficiencies (62-84%).[3] Fields flares without combustion enhancements (e.g., knockout drums to collect liquids prior to entering the flare; flame retention devices; pilots) have a much lower efficiency compared to properly designed and operated industrial flares.[4] Other factors, such as improper liquids removal,[5] low heating value of the fuel,[6] flow rate of gas,[7] and high wind speeds,[8] also decrease the combustion efficiency of flares.

Differing opinion: The one study cited is the only flare study that found low destruction efficiencies when burning production type gas streams. A number of other studies have confirmed destruction efficiencies >98% - which is the EPA guidance. A cooperative study, known as the international flare consortium study, is underway now and is testing destruction efficiencies across a wide range of gas types, flare types, and conditions.

There is a dearth of information on combustion efficiencies for flares used during well completion events, but given the fact that these flares are more rudimentary than industrial or even solution gas flares, it is highly possible that they have even lower combustion efficiencies.

Differing opinion: There are a number of very well done flare studies published.

When flares burn inefficiently, a host of hydrocarbon by-products that include highly reactive VOCs and polycyclic aromatic hydrocarbons, may be formed.[9] Leahey et al. (2001) found more than 60 hydrocarbon by-products, including known carcinogens such as benzene, anthracene and benzo(a)pyrene, downwind of a natural gas flare estimated to be operating at 65% combustion efficiency.[10] The inefficient burning of hydrocarbons also produces soot (particulate matter).[11] Additionally, nitrogen oxides are formed during the combustion process, even if the flare gas does not contain nitrogen.[12]

Differing opinion: The one study cited is the only flare study that found low destruction efficiencies when burning production type gas streams. A number of other studies have confirmed destruction efficiencies >98% - which is the EPA guidance. A cooperative study, known as the international flare consortium study, is underway now and is testing destruction efficiencies across a wide range of gas types, flare types, and conditions.

See the Endnotes for a table that summarizes the potential health and environmental effects related to compounds released during flaring and venting.[13]

Differing opinion: Not having access to the original table(s), it appears that errors may have occurred when it was adapted given the unwarranted combination of gas constituents and combustion products in one table and some obvious flaws (i.e., VOCs, SO2 and NOx contributing to particulate pollution but not aggravating respiratory conditions).

Flares operated during well completion activities handle enormous volumes of gas, which is either vented or flared over a short period of time. The amounts of HAPs and VOCs produced during a typical well completion in Wyoming have been calculated. It has been estimated that a single well completion event, which lasts an average of 10 days, releases:

- 115 tons of VOCs, and 4 tons of HAPs (assumption: 100% venting); or
- *86* tons VOCs, and *3* ton HAPs (assumption: half of the gas is flared per completion, and the flare operates at 50% efficiency).[14]

Differing opinion: Many completions in Wyoming – particularly those with gas flow rates in the 4 MMSCF/day range suggested above – are completed using flareless completion techniques which significantly reduces volume flared (75 to 90% reduction). However, use of these techniques is limited to those areas where the reservoir pressure is high enough to clean up the well and get the gas into the pipeline.

While it is clear that flaring reduces the volume (mass) of VOCs and HAPs, questions remain, such as: what are the particular VOC and HAP compounds released during both venting and flaring; what are the concentrations of these compounds in ambient air; [15] and can well completion flares somehow be designed (e.g., better liquid removal, lower gas flow rates going to the flare) to more effectively destroy hazardous compounds.

For a true assessment of the relative benefits of flaring vs. venting (especially with respect to human health), there is a need for a better assessment of venting/flaring emissions from well completions in the San Juan Basin. This assessment should determine both volumes of emissions, and provide a characterization of VOCs, HAPs and other compounds emitted (volumes and species) during well completion venting and flaring.

II. Description of how to implement

Using methods similar to those used in Wyoming, calculations could be performed to estimate the amount of VOCs and HAPs released from flaring and venting during well completion events in the San Juan Basin. Information requirements include:

- volume of gas released (vented or flared) per well completion
- VOC and HAP weight % of the natural gas
- estimates of combustion efficiency of flares
- estimates of how often flares are extinguished (resulting in venting of gas)

Monitoring downwind of sites that are flaring and/or venting is needed, to better characterize concentrations and species of VOCs and HAPs, as well as other flaring by-products.

A. Mandatory or voluntary
Initially, it could be a voluntary initiative, but if that does not produce data or results there may need to be mandatory reporting and monitoring requirements.

B. Indicate the most appropriate agency(ies) to implement
State oil and gas commissions could require the reporting of well completion emissions volumes; and environment/health departments would be the appropriate agencies to require monitoring of venting and flaring emissions.

III. Feasibility of the option
A. Technical
Emissions volumes from well completions have been determined for Wyoming, so presumably it is technically feasible to determine volumes for the San Juan Basin. If the data do not exist, perhaps the monitoring work group could work with industry to calculate or develop estimates of these volumes specific to the San Juan Basin.

Researches in Alberta have been able to determine combustion by-products using on-site analytical equipment or through absorbent samplers for confirmatory analyses by combined gas chromatography/mass spectrometry. Flare combustion efficiency were then calculated using a carbon mass balance of combustion products identified in the emissions. See Strosher (1996), Endnote 4.

B. Environmental
None.

C. Economic
Emissions volumes from well completions: low cost.
The identification of compounds emitted during venting and combustion: unknown.

IV. Background data and assumptions used See Endnotes Section.

V. Any uncertainty associated with the option
High uncertainty: depends on willingness of industry and regulators to undertake the necessary data collection.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None.

Notes:
1. Proportions calculated based on data from: Mansell, G.E. and Dinh, T. (ENVIRON International). September 2003. Emission Inventory Report - Air Quality Modeling Analysis For The Denver Early Action Ozone Compact: Development of the 2002 Base Case Modeling Inventory. p. 3-5. http://apcd.state.co.us/documents/eac/2002%20Modeling%20EI.pdf

Table 3-5. Average gas profiles (% composition) by formation for the San Juan Basin

	Mesa Verde	Dakota	Pictures Cliffs	Gallup	
Nitrogen	0.212	1.603	0	0.965	
Carbon Dioxide	1.388	1.034	1.403	0.639	
Methane	84.372	74.979	87.736	76.944	
Ethane	8.221	12.163	6.373	10.823	
Propane	3.19	6.488	2.651	6.552	
Butanes	1.432	2,532	1,148	2.551	
Pentanes	0.727	0.765	0.418	0.948	
Hexanes	0.459	0.437	0.270	0.578	
Benzene	0.0145	0.016	0.003		
Toluene	0.00706	0.003	0.0014		
Ethyl Benzene	0.00037	0.0001	0.0002		
Xylene	0.002	0.0006	0.001		
Calculated VOC and HAP content (not in original chart)					Average for all formations
HAPS (BTEX + hexane)	0.483	0.457	0.276	0.578	0.4483
VOCs (C1-C4)	97.94	96.93	98.33	97.82	97.753

2. Hewitt, J. (Bureau of Land Management). 2005. "H2S Occurrences San Juan Basin," a presentation at Hydrogen Sulfide: Issues and Answers Workshop. http://octane.nmt.edu/sw-pttc/proceedings/H2S_05/BLM_H2S_SanJuanBasin.pdf

3. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996.

Strosher (1996) found flaring efficiencies of 62-71% and 82-84% for sweet and sour gas flares, respectively. The sweet gas had a higher liquid hydrocarbon content than the sour gas being flared. Leahy et al. (2001, citation in Endnote 9) observed flare efficiencies of 68 ±7 % at sweet and sour gas flares in Alberta.

4. Seebold, J., Davis, B., Gogolek, P., Kostiuk, L., Pohl, J., Schwartz, B., Soelberg, N., Strosher, M., and Walsh, P. 2003. "Reaction Efficiency of Industrial Flares: the perspective of the past." International Flare Consortium, Combustion Canada '03 Paper. http://www.nrcan.gc.ca/es/etb/cetc/ifc/id4_e.html

5. Russell, J. and Pollack, A. (ENVIRON International). 2005. Final Project Report: Oil And Gas Emission Inventories For The Western States. Report prepared for the Western Governors' Association. Appendix A, Wyoming Emission Factor Documentation. p. A-2.
http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/WRAP_Oil&Gas_Final_Report.122805.pdf

When liquid content is too high, flares don't or won't ignite.

6. Kostiuk, L.W., M.R. Johnson & R.A. Prybysh. 2000 "Recent Research on the Emission from Continuous Flares," Paper presented at CPANS/PNWIS–A&WMA Conference (Banff, Alberta, April 10-12). Cited in: Seebold et al. (2003).

7. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996. p. 85.

Combustion efficiencies decreased from 70.6% (flow rate of 1 m3/min) to 67.2 % (flow rate of 5-6 m3/min) for sweet gas being flared at an oil tank battery in Alberta.

Increasing the flow increased the volatile hydrocarbons by about 33%, and the non-volatiles by three times the concentrations found in the lower volume flow.

8. Leahey, Douglas M., Preston, Katherine and Strosher, Mel. 2001. Theoretical and Observational Assessments of Flare Efficiencies," Journal of the Air & Waste Management Association. Volume 51. p. 1615

"It has been shown, as well, that flaring can be efficient only at low wind speeds because the size of the flare flame, which is an indicator of flame efficiency, decreases with increasing wind speed. Therefore, the flaring process could routinely result, during periods of moderate to high wind speeds, in appreciable quantities of products of incomplete combustion such as anthracene and benzo(a)pyrene, which can have adverse implications with respect to air quality."
9. Seebold, J., Gogolek, P., Pohl, J., and Schwartz, R. 2004. "Practical implications of prior research on today's outstanding flare emissions questions and a research program to answer them," Paper presented at the AFRC-JFRC 20004 Joint International Combustion Symposium, Environmental Control of Combustion Processes: Innovative Technology for the 21st Century. (Oct. 10-13, 2004; Maui, Hawaii). http://www.nrcan.gc.ca/es/etb/cetc/ifc/id12_e.html
For example, during the 1990s, research conducted as part of the Petroleum Environmental Research Forum's project 92-19 "The Origin and Fate of Toxic Combustion By-Products in Refinery Heaters" showed that even when burning laboratory grade methane "pure as the drifted snow" traces of higher molecular weight compounds not originally present in the fuel are found in the flue gas (e.g., ethylene, propylene, butadiene, formaldehyde, benzene, benzo(a)pyrene and other hydrocarbons in the gas phase up through coronene).
Seebold, et al. also report that, "the external combustion of hydrocarbon gas mixtures by any means, including flaring, literally manufactures and subsequently emits to the atmosphere traces of all possible molecular combinations of the elemental constituents present either in the fuel or in the air including the ozone precursor highly reactive volatile organic compounds (HRVOCs) and the carcinogenic hazardous air pollutants (HAPs).
10. Leahey, Douglas M., Preston, Katherine and Strosher, Mel. 2001. Theoretical and Observational Assessments of Flare Efficiencies," Journal of the Air & Waste Management Association. Volume 51. p.1614. http://www.awma.org/journal/pdfs/2001/12/Leahey.pdf

Speciated data for combustion products observed downwind of the sweet gas flare using solvent extraction methods.

Product	Volume (mg/m3)	Product	Volume (mg/m3)
Nonane	0.41	9h-fluorene, 3-methyl-	3.05
Benzaldehyde (acn)(dot)	0.53	Phenanthrene	10.01
Benzene, 1-ethyl-2-methyl-	0.13	Benzo(c)cinnoline	2.06
1h-indene, 2,3-dihydro-	0.34	Anthracene	42.11
Decane	1.72	1h-indene, 1-(phenylmethylene)-	1.94
Benzene, 1-ethynyl-4-methyl-	9.83	9h-fluorene, 9-ethylidene-	0.89
Benzene, 1,3-diethenyl-	1.27	1h-phenalen-1-one	1.86
1h-indene, 1-methylene-	0.28	4h-cyclopenta[def]phenanthrene	3.50
Azulene	21.20	Naphthalene, 2-phenyl-	1.98
Benzene, (1-methyl-2-cyclopropen-1-yl)-	11.47	Naphthalene, 1-phenyl-	1.82
1h-indene, 1-methyl-	1.66	9,10-anthracenedione	0.94
Naphthalene (can)(dot)	99.39	5h-dibenzo[a,d]cycloheptene, 5-methylene-	0.75
Benzaldehyde, o-methyloxime	0.27	Naphthalene, 1,8-di-1-propynyl-	1.14
1-h-inden-1-one, 2,3-dihydro-	0.74	Fluoranthene 51.35 Benzene, 1,1'-(1,3-butadiyne-1,4-diyl)bis-	2.07

Naphthalene, 2-methyl-	9.25	Pyrene	32.37
Naphthalene, 1-methyl-	6.18	11h-benzo[a]fluorene	2.25
1h-indene, 1-ethylidene-	1.22	Pyrene, 4-methyl-	9.13
1,1'-biphenyl	58.70	Pyrene, 1-methyl-	8.38
Naphthalene, 2-ethyl-	1.87	Benzo[ghi]fluoranthene	10.16
Biphenylene	42.81	Cyclopenta[cd]pyrene	29.77
Naphthalene, 2-ethenyl-	7.32	Benz[a]anthracene	17.33
Acenaphthylene	7.15	Chrysene	2.12
Acenaphthene	2.93	Benzene, 1,2-diphenoxy-	1.94
Dibenzofuran	0.88	Methanone, (6-methyl-1,3-benzodioxol-5-yl)phenyl-	0.95
1,1'-biphenyl, 3-methyl-	0.31	Benzo[e]pyrene	0.71
1h-phenalene	21.01	Benzo[a]pyrene	1.03
9h-fluorene	41.09	Perylene	0.62
9h-fluorene, 9-methyl-	1.07	Indeno[1,2,3-cd]pyrene	0.15
Benzaldehyde, 4,6-dihydroxy-2,3-dimethyl	1.16	Benzo[ghi]perylene	0.26
9h-fluorene, 9-methylene-	1.07	Dibenzo[def,mno]chrysene	0.15
		Coronene	0.08

11. U.S. Environmental Protection Agency. 2000. Office of Air Quality Planning and Standards. “Industrial Flares,” AP-42 Fifth Edition. Vol. 1: Stationary Point and Area Sources. p. 13.5-3.
Tendency to smoke or make soot is influenced by fuel characteristics and by amount and distribution of oxygen in the combustion zone. All hydrocarbons above methane tend to soot. Soot from industrial flares is eliminated by adding steam or air.
Soot emissions factors developed by EPA for industrial flares are: non-smoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.
12. K.D. Siegel. 1980l. Degree of Conversion of Flare Gas in Refinery High Flares. Dissertation. University of Karlsruhe, Germany. Cited in: USEPA Office of Air Quality Planning and Standards. 2000. “Industrial Flares,”AP-42 Fifth Edition. Volume 1: Stationary Point and Area Sources. p.13.5-5.
Even waste gas that does not contain nitrogen compounds form NO. It is formed either by fixation of atmospheric nitrogen with oxygen, or by the reaction between hydrocarbon radicals and atmospheric N by way of intermediate states, HCN, CN and OCN.
13. Health and Environmental Effects of Chemicals Released During Venting and Flaring.

	VOCs	SO2	NOx	CO	PAHs	H2S	HAPs	SMOKE/ SOOT
Contributes to particulate pollution that can cause respiratory illness, aggravation of heart conditions and asthma, permanent lung damage and premature death.								
	FLARING	FLARING	FLARING					FLARING
Aggravates respiratory conditions						VENTING		
								FLARING

	VOCs	SO2	NOx	CO	PAHs	H2S	HAPs	SMOKE/ SOOT
Can cause health problems such as cancer	VENTING						VENTING	
	FLARING				FLARING		FLARING	
Can cause reproductive, neurological, developmental, respiratory, immune system, and other health problems.							VENTING	
							FLARING	
Reacts with other chemicals leading to ground-level ozone and smog, which can trigger respiratory problems	VENTING							
	FLARING		FLARING					
Reacts with common organic chemicals forming toxins that may cause bio-mutations								
			FLARING					
Affects cardiovascular system and can cause problems within the central nervous system						VENTING		
Causes haze that can migrate to sensitive areas such as National Parks	VENTING							
	FLARING	FLARING	FLARING	FLARING				FLARING
Contributes to global warming	VENTING							

Adapted from: EPA Office of Inspector General. 2004. EPA Needs to Improve Tracking of National Petroleum Refinery Program Progress and Impacts. Appendix D.

14. Russell, J. and Pollack, A. (ENVIRON International). 2005. Final Project Report: Oil And Gas Emission Inventories For The Western States. Report prepared for the Western Governors' Association. Appendix A, Wyoming Emission Factor Documentation. p. A-2.
http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/WRAP_Oil&Gas_Final_Report.122805.pdf

15. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996. p. 28.
Strosher measured concentrations of hydrocarbon compounds emitted from sweet and sour solution gas flares in Alberta, and then predicted ground-level concentrations of HAPs at various locations around the well location. Predicted values of some polycyclic aromatic hydrocarbons in the vicinity of sweet and sour gas flares were comparable to concentrations found in large industrial cities, while predicted values of hazardous VOCs released during flaring were below ambient air quality standards.

Mitigation Option: Co-location/Centralization for New Sources

I. Description of the mitigation option

This mitigation option would involve co-locating and/or centralizing new oil/gas field facilities, including roads, well pads, utilities, pipelines, compressors, power sources and fluid storage tanks, wherever possible, to reduce surface impacts, fugitive dust, engine emissions and gas field traffic.

In general, co-location and/or centralization of new facilities would result in overall reductions in surface disturbance, vehicular traffic, and number of facilities. Potential benefits from this strategy include fugitive dust reduction (due to decreased traffic and less overall new surface disturbance), vehicle emission reductions, reduced road maintenance, safer roads as a result of decreased traffic, and oil/gas field engine emission reductions. The potential for reduced engine emissions is due in part to lowering cumulative horsepower requirements by using larger, more efficient engines, and in part to groups of smaller engines with relatively high emission rates per hp/hr being replaced by fewer, larger engines with relatively low emission rates per hp/hr. Implementation costs for this mitigation option would fall exclusively on the energy companies, but such costs could be partially offset by the economic benefits of having fewer facilities to construct, maintain and ultimately reclaim.

Tradeoffs include increased impacts at co-located/centralized sites. Co-locating well bores on a single pad results in larger pad sizes that may not fit well with pre-existing conditions. Centralizing facilities would increase vehicle emissions locally and potentially produce local air quality, noise, visual and traffic safety issues. Additionally, aggregating produced water in one location increases the potential for a catastrophic release.

II. Description of how to implement

A. This mitigation option should be implemented on a voluntary basis, with the approach emphasized by the appropriate regulatory agency during the planning and permitting processes for oil/gas field facilities and utility corridors (pipelines, power lines, etc.). Consideration should be given to economic and environmental impacts, as well as current and future land management activities. Ideally, oil/gas field operators and regulatory agencies would coordinate on a regular basis to identify development plans that minimize new construction and maximize efficiencies. Cooperation between operators in the same development area would make this option even more effective, but multiple economic and regulatory constraints exist that make such coordination difficult.

B. State and Federal lands and minerals management agencies would be able to emphasize this approach at various stages of the planning and permitting process. In addition, State and Federal air regulatory agencies could emphasize this approach if multiple air quality permit applications are submitted concurrently for the same general area.

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option. This option is best suited for areas of known or high potential for economic oil/gas field production. This option can be implemented most effectively when planning for oil/gas field- or lease-wide development activities, such as in-fill drilling and plans of development for multiple wells.

B. Environmental: Co-location and/or centralization of new facilities would generally have numerous environmental benefits.

C. Economic: Economic feasibility of this option will vary on a project-level basis. Higher initial costs may be offset by overall cost reductions due to fewer facilities to construct, operate and reclaim. Additional cost savings may result because co-located/centralized facilities can be more efficient than dispersed facilities.

IV. Background data and assumptions used
This option is best suited for areas with existing or high potential for economic gas/oil field production.

V. Any uncertainty associated with the option
Low. While implementation of this option may cause greater noise, emission, and visual impacts at fewer, co-located/centralized locations, the overall effect would be a reduction in oil/gas field environmental impacts.

VI. Level of agreement within the work group for this mitigation option Unknown at this time

VII. Cross-over issues to the other source groups
Road-related impacts are an element of this mitigation option being looked at by the Other Sources Workgroup. Two other mitigation strategies (Optimization/Centralization and Reduced Truck Traffic by Centralizing Produced Water Storage Facilities) look at the compression and produced water facets of this mitigation option in greater detail and are presented in the Oil and Gas section of this Task Force Report. Assistance from the Cumulative Effects work group to quantify potential dust, vehicle traffic and overall emission reductions resulting from co-location and/or centralization would be helpful.

VIII. References

http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices.html

http://www.westgov.org/wga/initiatives/coalbed/

http://bogc.dnrc.state.mt.us/website/mtcbm/webmapper_cbm_info_res.htm

Mitigation Option: Control Glycol Pump Rates

I. Description of the mitigation option

Most dehydration systems use triethylene glycol (TEG) as the absorbent fluid to remove water from natural gas. As TEG absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). As TEG is regenerated through heating in a reboiler, absorbed methane, VOCs, and HAPs are vented to the atmosphere with the water, wasting gas and money. The amount of methane absorbed, and used as assist gas for Kimray type pumps, and vented is directly of the TEG Dehydrator, but continue to circulate TEG at rates two or three times higher than necessary, resulting in little improvement in gas moisture quality but much higher methane emissions and fuel use. Reducing TEG circulation rates reduce methane emissions at negligible cost.

Economic burdens are minimal since this practice simply requires the pump rate to be manually adjusted.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of lower TEG circulation rates should be "voluntary" since the measure would enhance recovery of natural gas and reduce emissions. Companies should be receptive to voluntarily implement this measure.

B. Indicate the most appropriate agency(ies) to implement**:** The state Air Quality Divisions should communicate this information.

III. Feasibility of the option

A. Technical: Controlling TEG circulation rates are technically feasible since it can be achieved by manually setting the pump rate.

B. Environmental: The environmental benefits of reduced VOC pollution are well documented. The reduction of methane, a greenhouse gas, can also be documented. Quantification of emission reductions can be achieved through the use of the GLYCALC model.

Due to the low field pressures in the San Juan basin area, most field dehydrators have been removed and dehydration is done at central facilities rather than dispersed locations. Due to this, this option will have very limited applicability and emission reductions associated with it.

C. Economic: The benefits can be quantified by the amount of methane and VOC that is not emitted to the atmosphere and rather sold as product.

IV. Background data and assumptions used

A. Gas production fields experience declining production as pressure is drawn-off the reservoir. Wellhead glycol dehydrators and their TEG circulation rates are designed for the initial, highest production rate, and therefore, become over-sized as the well matures. It is common that the TEG circulation rate is much higher than necessary to meet the sales gas specification for moisture content.

B. The methane emissions from a glycol dehydrator are directly proportional to the amount of TEG circulated through the system. The higher the circulation rate, the more methane, is vented from the regenerator. Over-circulation results in more methane emissions without significant and necessary reduction in gas moisture content.

C. Operators can reduce the TEG circulation rate and subsequently reduce the methane emissions rate, without affecting dehydration performance or adding any additional cost.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option

Although a general discussion of this option has not occurred between the working group members, it is doubtful a disagreement about controlling TEG circulation rates would occur.

Source of Information: **"**Optimize Glycol Circulation and Install of Flash Tank Separators in Dehydrators", U.S. EPA Natural Gas Star Program.

Mitigation Option: Combustors for Still Vents

I. Description of the mitigation option

Most dehydration systems use triethylene glycol (TEG) as the absorbent fluid to remove water from natural gas. As TEG absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). The TEG is then distilled to strip water and consequently VOC from the TEG. Vapors and/or liquids in the still vent are typically greater than 90% volume water, with the balance being hydrocarbons along with small quantities of carbon dioxide and nitrogen. The still vent column is typically released to the atmosphere that includes emissions of hydrocarbons. It is important to note that gas composition is an important consideration in determining the need to install flares. Some natural gas, such as coalbed methane gas contains little, if any VOC component, and would not result in VOC emissions.

In order to reduce these emissions, combustion devices can be installed to combust hydrocarbon emissions, including VOCs, instead of venting them to the atmosphere. The combustion technology typically consists of an enclosed "flare/burner." It does require a condenser and separator upstream of the combustion device to avoid liquid hydrocarbons routed to the combustion device.

II. Description of how to implement

A. Mandatory or voluntary: The requirement for control of emissions from glycol dehydrators is included in the EPA's area source *Onshore Natural Gas Processing* MACT rules that have been proposed/promulgated. After careful analysis, EPA set emission and throughput based criteria to trigger these control requirements. Any control at lower emission or throughput rates should be voluntary.
B. Indicate the most appropriate agency(ies) to implement**:** The state Air Quality Divisions should develop the regulatory program to administer this program.

III. Feasibility of the option

A. Technical: Installing condensers and combustion devices to control emissions from dehydrator still vents is technically feasible since it is already being applied in various locations where controls of these emissions have been mandated.
B. Environmental: The environmental benefits of reduced VOC emissions are well documented. The reduction of methane, a greenhouse gas, can also be documented. Actual benefits are dependent on the amount and composition of the gas being dehydrated and are highly variable. Little benefit is expected for the San Juan basin due to the lack of field dehydration.
C. Economic: Costs are for a typical condenser and smokeless combustion chamber large enough to service a dehydrator in Wyoming are about $35,000 installed. There are no revenues from the gas as it is destroyed through combustion, and there is a fuel cost of about $1,800 per year for each pilot (at $3 per Mcf of gas).

IV. Background data and assumptions used Wyoming oil and gas presumptive BACT guidance.

V. Any uncertainty associated with the option Low where applicable.

VI. Level of agreement within the work group for this mitigation option

Although a general discussion of this option has not occurred between the working group members, it is unknown about the degree of acceptance regarding the use of combustors for still vents.

Source of Information: "Install Flares"**,** PRO Fact Sheet No. 905, U.S. EPA Natural Gas Star Program. Gas Research Institute, Control Device Monitoring of Glycol Dehydrators; Condenser Efficiency Measurements and Modeling, 1997.

EXPLORATION & PRODUCTION: WELLS

Mitigation Option: Installation and/or Optimization of a Plunger Lift System

I. Description of the mitigation option

Overview

In mature gas wells, the accumulation of fluids in the well-bore can impede and sometimes halt gas production. Fluids are removed and gas flow maintained by removing accumulated fluids through the use of artificial lift (such as a beam pump) or enhanced fluid lift treatments or techniques, such as plunger lifts, velocity strings, swabbing, soap injection, or venting the well to atmospheric pressure (referred to as "blowing down" the well). Fluid removal operations, particularly well blow-downs, may result in substantial methane and associated VOC emissions to the atmosphere.

Installing a plunger lift system can be a cost-effective alternative for removing liquids on wells where the well-bore configuration, pressure profiles, and production characteristics enable its application. Plunger lift systems have the additional benefit of potentially increasing production, as well as significantly reducing methane and associated VOC emissions associated with blow-down operations. A plunger lift uses gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

Air Quality and Environmental Benefits

The installation of a plunger lift system serves as an interim well-bore deliquification methodology for the period between natural flowing lift and full artificial lift and can yield environmental and production benefits while reducing well blow-downs and their associated emissions. The extent and nature of these benefits depend on the individual well characteristics and the method of plunger lift control and operation.

New automation systems and control capabilities can improve plunger lift system optimization, monitoring, and control. For example, technologies such as programmable logic controllers and remote transmitter units can allow operators to control plunger lift systems thorough control algorithms or remotely, without regular field visits. These systems can offer enhanced plunger lift operation and effectiveness versus older plunger control systems.

By reducing the need for well-bore blow-down, plunger lift systems can lower emissions. Reducing repetitive remedial treatments and well work-over may also reduce methane and associated emissions. Natural Gas STAR partners have reported annual gas savings averaging 600 Mcf per well by avoiding blow-down and an average of 30 Mcf per year by eliminating or reducing well work-overs.

Economics

Lower capital and operational cost versus installing full artificial lift equipment (such as a beam pump). The costs of installing and maintaining a plunger lift are generally lower than the cost to install and maintain artificial lift equipment.

Lower well maintenance and fewer remedial treatments. Overall well maintenance costs are reduced because periodic remedial treatments such as swabbing or well blow-downs are reduced or no longer needed with plunger lift systems.

More effective well-bore deliquification and continuous production may improve gas production rates and increase efficiency. With proper optimization and control, plunger lift systems can also conserve the well's lifting energy and increase gas production. Regular fluid removal allows the well to produce gas continuously and helps prevent fluid loading that periodically halts gas production or “kills” the well. Often, the continuous removal of fluids results in daily gas production rates that are higher than the production rates prior to the plunger lift installation.

Reduced paraffin and scale buildup. In wells where paraffin or scale buildup is a problem, the mechanical action of the plunger running up and down the tubing may prevent particulate buildup inside the tubing. Thus, the need for chemical or swabbing treatments may be reduced or eliminated. Many different types of plungers are manufactured with “wobble-washers” to improve their “scraping” performance.

Other economic benefits. In calculating the economic benefits of plunger lifts, the savings from avoided emissions and enhanced production are only two factors to consider in the analysis. Additional savings may result from lower operational and well work costs.

Tradeoffs
Plunger lift systems do fail and can require additional maintenance versus blowing wells down. If return velocity is not controlled they may also “launch” through the plunger receiver and cause wellhead failure. Also, dependent on the control systems, they may require regular operator intervention.

Burdens
Installation of plunger lift systems can involve substantial costs particularly if changes to the well-bore tubulars are required. If adequate control systems and a means to power them are not available on a particular well, their installation will require additional expenditures.

II. Description of how to implement
A. Mandatory or voluntary: This option should be voluntary given the restrictions on applicability posed by well-bore configuration, pressure and build-up profile, and production characteristics. Each well must be evaluated for feasibility of plunger lift systems. A large number of wells in the Four Corners area already have artificial lift systems or other enhanced deliquification techniques already installed. Requiring all wells in the basin to replace other means of enhanced or artificial lift would be logistically and operationally unreasonable. A large percentage of the producing wells in the 4-corners area are already equipped with plunger lift systems. Most operators have an ongoing well evaluation program to determine the appropriate deliquification technology to apply to any particular well.
B. Indicate the most appropriate agency(ies) to implement**:** Non-applicable – voluntary implementation. However, workshops on plunger lift applicability, control, and operation may enhance implementation.

III. Feasibility of the option
A. Technical: The technical considerations necessary for plunger lift systems are well known and plunger lift systems are feasible where the well characteristics enable application. For very low pressure/flow environments, such as portions of the San Juan Basin, operation of plunger lifts may require periodic venting (blow-down) of well-bores to the atmosphere to generate enough differential energy to lift the plunger and associated fluids. Advanced control systems can significantly reduce the need for this type of blow-down but require robust automation capabilities.
B. Environmental: There are no known environmental issues with plunger lift implementation and they typically reduce emissions.
C. Economic: the economics of applying plunger lift technology to a particular well must be evaluated on a well-by-well basis. For wells where they are applicable, plunger lift systems are generally economic.

IV. Background data and assumptions used N/A

V. Any uncertainty associated with the option

Assuming a well-by-well evaluation of applicability the uncertainty associated with plunger lift implementation should be low. Due to the large number of wells already equipped with plunger lift or other enhanced or artificial lift systems the scope of available implementation may be limited.

VI. Level of agreement within the work group for this mitigation option

Still being evaluated, but based upon information to date it should be high.

Mitigation Option: Implementation of Reduced Emission Completions (Green Completions)

I. Description of the mitigation option

The "green completions" control method reduces methane losses during gas well completions. During well completions it is necessary to clean out the well bore and the surrounding formation perforations. This is done both after new well completions and after well workovers. Operators produce the well to an open pit or tanks to collect sand, cuttings and reservoir fluids for disposal. Normal practice during this process is to vent or flare the natural gas produced. Venting may lead to dangerous gas buildup, so flaring is preferred where there is no fire hazard or nuisance issue (concerns about smoke, light, noise, etc.). Green completions recover the natural gas and condensate produced during well completions or workovers. This is accomplished using portable equipment to process the gas and condensate so it is suitable for sale. The additional equipment may include more tanks, special gas-liquid-sand separator traps, and portable gas dehydration. The recovered gas is directed through permanent dehydrators and meters to sales lines, reducing venting and flaring. "Green completion" techniques are only applicable where the reservoir pressure and flow is sufficient to clean-up a well bore after completion and still have sufficient pressure to enter the collection system/pipeline. With the depleted status of the conventional San Juan basin reservoirs and the characteristics of coal bed methane reservoirs; this is not an available option for the SJ basin area.

II. Description of how to implement

A. Mandatory or voluntary

This process can be mandatory or voluntary.

B. Indicate the most appropriate agency(ies) to implement

For the 4 Corners area, State regulatory agencies could require green completions through regulation or policy. For example, in the Pinedale, WY area the State of Wyoming, BLM, and operators have agreed to minimize flaring operations through use of green completions. FLMs could require this process through stipulations or conditions of approval in leases and applications for permits to drill.

III. Feasibility of the option

A. Technical

The green completion process can apply to the drilling of all natural gas wells, however, a sales line connection and sales agreements need to be arranged before the well drilling is completed. There are operational, access and other considerations that make this a case determination.

Differing opinion: This technique is not feasible in the SJ basin – see above.

The green completion process has been reviewed by EPA and is listed under "Recommended Technologies and Practices" on EPA's Natural Gas Star Program web site: http://www.epa.gov/gasstar/techprac.htm **Differing opinion:** This technology may not be applicable in all cases, and needs careful consideration. Different formations typically require different completion techniques that this technology may not be suited to handle. E.g. many operators use compressed air to fracture coal wells. Air mixed with natural gas cannot be shipped to a pipeline due to the high potential for spontaneous combustion under typical pipeline temperatures and pressures. Additionally, oxygen contamination of natural gas causes additional corrosion risks to gathering lines. Separation of air from natural gas is presently not feasible or part of the process equipment used in "green completions."

B. Environmental

Nationally EPA has estimated that 25.2 billion cubic foot (Bcf) of natural gas can be recovered annually using Green Completions - 25,000 million cubic foot (MMcf) from high pressure wells, 181 MMcf from low pressure wells, and 27 MMcf from workovers. This reduces emissions of methane (a greenhouse gas), condensates (hazardous air pollutants), and nitrogen oxides (precursor to ozone formation and visibility degradation) formed when gas is flared. An EPA Gas Star Partner reported an estimated methane emissions reduction, as the total recovered from 63 wells, of 7.4 MMcf per year, which is 70 percent of the gas formerly vented to the atmosphere.

C. Economic

A methane savings of 7 MMcf per year based on completing 60 wells per year at the average recovery reported by an EPA Gas Star partner. The partner also reported recovering a total of 156 barrels of condensate from the 63 wells, an average of 2.5 barrels per well.

The capital costs include additional portable separators, sand traps, and tanks at a cost reported by the partner of $180,000. This equipment would be moved from well-to-well, so amortizing the cost over 10 years and doing 60 wells per year, the annual capital charges would be under $10,000. Incremental operating costs are assumed to be over $1,000 per year. At a natural gas price of $3 per Mcf and condensate price of $19 per barrel, green completions will pay back the costs in about 1 year. This information is for green completions in the Green River Basin area of Wyoming and is for much higher rate wells with much higher pressures and energy than the SJ basin wells.

IV. Background data and assumptions used

Information on Green Completions comes from EPA's Natural Gas Star Program web site: http://www.epa.gov/gasstar/techprac.htm

V. Any uncertainty associated with the option

Low, if the well is part of an in-fill and a sales line connection is available. Other situations may not be suitable for green completions.

Differing opinion: Very High – this is not a viable option for the SJ basin area – see above.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None.

Mitigation Option: Convert High-Bleed to Low or No Bleed Gas Pneumatic Controls

<u>I. Description of the mitigation option</u>

This option would encourage oil and gas producers and pipeline owners and operators to replace or retrofit high-bleed natural gas pneumatic controls. This option should be considered when replacement of pneumatic controls with compressed instrument air systems is not practical or feasible (e.g. no electric power supply). It would enhance EPA's current efforts in the Natural Gas Star Program and make them specific to the San Juan Basin. This would result in a significant reduction in methane emissions as well as achieve cost savings for the companies.

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. As part of <u>normal</u> operation, natural gas powered pneumatic devices release or bleeds gas to the atmosphere and, consequently, are a leading source of methane emissions from the natural gas industry. High–bleed pneumatic devices are defined as those with bleed rates of 6 standard cubic feet per hour (scfh) or 50 thousand cubic feet (Mcf) per year. An EPA study in 2003 reported the constant bleed of natural gas from these controllers was collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 24 billion cubic feet (Bcf) per year in the production sector, 16 Bcf from processing and 14 Bcf per year in the transmission sector. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network.

Companies have found that the payback period can be less than a year for most retrofits from high-bleed to low-bleed pneumatic controllers. Recent experience indicates that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted.   If electric power is available, conversion from natural gas-powered pneumatic control systems to compressed instrument air systems will result in greater methane emissions reductions. However, the investment payback period will likely be longer, and may not be cost effective in some cases.

In compressed instrument air systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. All other parts of a gas pneumatic system work the same way with air as they do with gas. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system.
Reducing methane emissions from pneumatic devices by converting to instrument air systems can yield significant economic and environmental benefits for natural gas companies including:

- Financial Return From Reducing Gas Emission Losses. In many cases, the cost of converting high-bleed to low-bleed pneumatic controllers can be recovered in less than a year.
- Lower Methane Emissions

<u>II. Description of how to implement</u>

A. <u>Mandatory or voluntary:</u> This program would be voluntary. Due to the fact that almost all high-bleed pneumatics have been replaced by the industry, the economic returns from implementing low bleed systems should motivate producers to implement them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.
B. Currently most operators have already replaced all high bleed with low bleed systems.
C. <u>Indicate the most appropriate agency(ies) to implement:</u> EPA and the State environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option
A. Technical: These systems are off-the-shelf and proven.
B. Environmental: The environmental benefits of replacing high-bleed with low-bleed pneumatic controls, in terms of lower methane emissions, have been documented by EPA. Companies reporting to EPA have reduced emissions by 50-260 Mcf per year per controller.
C. Economic: EPA reports that replacing or retrofitting high-bleed units with low-bleed units have a payback of five to 21 months.

IV. Background data and assumptions used
See the website for EPA's Natural Gas Star Program: http://www.epa.gov/gasstar/index.htm

In particular, the lessons learned summaries for low-bleed pneumatics:
http://www.epa.gov/gasstar/pdf/lessons/ll_pneumatics.pdf

V. Any uncertainty associated with the option
Low. This is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups
Cumulative effects should review oil and gas tasks and rank those most effective as priorities over those less effective or cost effective.

Mitigation Option: Utilizing Electric Chemical Pumps

I. Description of the mitigation option

This option involves replacing existing gas drive pumps with solar powered, electric-driven chemical pumps. The air quality benefits would be to minimize methane and VOC emissions to the atmosphere (Methane, VOC).

Economic burdens are significant but not insurmountable if the cost recovery factor from reduced fuel usage over the anticipated life of the unit shows a positive return on investment.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to install electric-driven, solar powered chemical pumps are envisioned as "voluntary" measures since the feasibility of installing insulation on new units or retrofitting existing units must be evaluated for a positive Net Present Value (NPV) or Return on Investment (ROI) in the Four Corners area. If the NPV or ROI meets a company's investment targets, then utilization of this technology should be encouraged as a best practice. There are no existing mandates by the respective Air Quality Control agencies to require electric drive pumps as BACT. Since the Four Corners area is not in ozone non-attainment and the cost economics will not always justify installation of insulation for economic benefit, a voluntary approach is recommended.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option

A. Technical: The purchase and installation of electrically driven chemical pumps is technically feasible. Currently some companies are installing these pumps on a trial basis to assure performance during the winter months.
B. Environmental: The environmental benefits of reduced Methane and VOC pollution are well documented.
C. Economic: The use of electric-driven, solar powered chemical pumps is economically feasible where the there is payback that meets the respective companies targets for investments (i.e., ROI or NPV). For existing older pumps exist on wells that have a future limited life, the economics may not justify the application of insulation.

IV. Background data and assumptions used

Most chemical pumps in the Four Corners area are utilized year round to achieve their objective.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option

There is general agreement among working group members that the use of electrical chemical pump technology in the Four Corners areas is economically unfeasible and a likely source for voluntary adoption if the economics show a sufficient NPV.

Mitigation Option: Solar Power Driven Wellsites and Tank Batteries

I. Description of the mitigation option

This option comprises a system of production equipment and controls powered by solar generated electricity (through Photovoltaic – PV - cells) at gas well production sites that are not served with grid power. In most cases solar power replaces pressurized fuel gas, which is usually vented to the atmosphere after use. The power supply consists of solar panels and batteries. The solar power is used for electric instruments, controllers, actuators for automatic valves and small additive (methanol) pumps. Optimization consists of selecting the best fit items of hardware, becoming familiar with the strengths and limitations of all of the individual items as well as the overall system and making modifications to improve performance.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory on all new wellsites with gas-assisted chemical injection pumps. Mandatory where economic at existing wellsites. Propose to define a standardized calculation to determine if it is economic. An example borrowed from the Alberta EUB – Energy & Utilities Board – Directive 60, agreed to by a multi-stakeholder group including the oil & gas industry, includes the following:

1) Before tax basis
2) Point to an agreed upon specific gas forecast report
3) Must have remaining reserves calculation and production forecast (NPV calculated over life of well/production)
4) Only incremental capital costs related to the solar PV skid system may be included
5) Long term inflation based on CPI forecast
6) Discount rate = prime lending rate + 3%
7) Only revenue minus net royalties from incremental gas conservation only to be included
8) Economic if NPV before tax > $0

B. Indicate the most appropriate agency(ies) to implement**:** The States on State land or Federal/Tribe on Indian country.

III. Feasibility of the option

A. Technical: In the past two years an operator in Alberta has installed over 40 of these systems. Supported by operations managers, instrumentation personnel carried out trials with solar systems and electrical equipment to arrive at a “best fit” arrangement. In summer 2006, this operator carried out a study with outside specialist consultants in energy consumption and emissions monitoring to evaluate the performance of the system. The results of the study were very positive, resulting in this operator making their solar PV system the company standard for gas well production. The primary reasons for this are to reduce fuel consumption in producing operations, increase sales gas revenues and reduce vent gas emissions. There are also operators in the US Rocky Mountain area using solar PV systems in comparable ways.

B. Environmental: Reduced VOC emissions and reduced methane emissions (with a global warming potential ~23 times greater than CO_2). Quantity of reduction would be dependent on number and bleed rate of pneumatic controllers, and size and supply gas use rate of pneumatic pump equipment, being replaced with electrically-powered devices.

C. Economic: Reduced fuel gas consumption so increased gas conservation and saleable product. These solar PV systems also minimize the requirement for expensive fuel gas regulators, shutdown devices and repair kits and stainless steel instrument tubing and fittings.

IV. Background data and assumptions used
See the presentation, "BP Canada Energy Company Innovative Methods for Reducing Greenhouse Gas - Low Emissions Wellsite" by Milos Krnjaja, BP Canada made at the "Energy Management Workshop for Upstream and Midstream Operations: Increasing Revenue through Process Optimization & Methane Emissions Reduction" in Calgary, Alberta Canada on 15-17 January 2007.
(http://www.methanetomarkets.org/events/2006/oil-gas/docs/15jan07-bp_canada_energy_company.pdf)

See the presentation, "Using Solar to Reduce Fugitive Gas Emissions" by Stuart Torr, Komex International made at the 2005 Energy Conservation and Air Emissions Technology Forum Wednesday, in Calgary, Alberta Canada on 19 October 2005.
(http://www.ptac.org/eet/dl/eetf0501p12.pdf)

See Database of State Incentives for Renewables and Efficiency (DSIRE) for a fast and convenient method to access comprehensive information on available state, local, utility, and federal **financial incentives** that promote renewable energy and energy efficiency.
(http://www.dsireusa.org/)

See Alberta Energy & Utilities Board – Directive 60 – Upstream Petroleum Industry Flaring, Incinerating, and Venting.
(http://www.eub.ca/docs/documents/directives/Directive060.pdf)

See Ber-Mac Electrical and Instrumentation for an example of a supplier of solar PV systems for instrumentation use. They have been in business since 1980 supplying electrical power and instrumentation equipment and services, both domestically and to international markets, supplying the needs of oil and gas companies all over the world. Their "Green Machine" is an environmentally-friendly, solar-powered operating system for new and existing wellsites.
(http://www.ber-mac.com/greenmachine.htm)

V. Any uncertainty associated with the option Low – a fair amount of industry experience and vendor capacity to-date.

VI. Level of agreement within the work group for this mitigation option
General agreement within working group members that this is viable.

EXPLORATION & PRODUCTION: PNEUMATICS / CONTROLLERS / FUGITIVES

Mitigation Option: Optical Imaging to Detect Gas Leaks

I. Description of the mitigation option
This option would encourage oil and gas producers and pipelines to use optical imaging to detect methane and other gaseous leaks from equipment, processing plants, and pipelines.

Optical imaging refers to a class of technologies that use principles of infrared light and optics to create an image of chemical emission plumes. They offer more cost-effective use of resources than traditional hand-held emissions analyzers, can screen hundreds of components or miles of pipeline relatively quickly and allow quicker identification and repair of leaks. The remote sensing and instantaneous detection capabilities of optical imaging technologies allow an operator to scan areas containing tens to hundreds of potential leaks, thus eliminating the need to visit and manually measure all potential leak sites.

Gas imaging can be either active or passive. Active gas imaging is accomplished by illuminating a viewing area with laser light tuned to a wavelength that is absorbed by the target gas to be detected. As the viewing area is illuminated, a camera sensitive to light at the laser wavelength images it. If a plume of the target gas is present in the imaged scene, it absorbs the laser illumination and the gas appears in a video picture as a dark cloud. Because it relies on the detection of backscattered radiation from surfaces in the scene, the process is referred to as Backscatter Absorption Gas Imaging (BAGI).

Passive gas imaging is based on a complex relationship between emission, absorption, reflection, and scatter of electromagnetic radiation. VOCs in the vapor phase have unique spectral emission and absorption properties. By measuring these properties, the gas species can be uniquely identified. By tuning the instrument's spectral response to the unique spectral region of the VOC, the camera can make an image of a gas plume.

There is a variety of technologies available and in different stages of development for imaging hydrocarbon gases. Plume imaging technologies include BAGI and Hyperspectral Imaging systems. Remote detection sensing instruments include Open-path Fourier Transform Infrared (OP-FTIR), Differential Absorption Spectroscopy (DOAS), Light Detection and Ranging (LIDAR-DIAL), and Tunable Diode Laser Absorption Spectroscopy (TDLAS). These instruments can be hand held or shoulder mounted, van mounted, or operated from a helicopter or fixed wing aircraft, depending on the technology and the facility to be inspected.

As an example, the ANGEL service, which uses Differential Absorption Lidar (DIAL), can detect specific hydrocarbon gases with color video imaging from a fixed wing aircraft, quantify the plume concentration, encode GPS data on the image, and cover 1000 miles per day. This technology is most suited to a facility such as a pipeline or tank farm. For a gas processing plant, a hand held or shoulder mounted camera may be the technology of choice.

The benefits of using optical leak detection in an inspection and maintenance program include:
- Reductions in hydrocarbon gas emissions, both greenhouse gases and hazardous air pollutants;
- Improved safety; and
- Typical payback of less than one year in reduced methane product losses.

II. Description of how to implement
A. Mandatory or voluntary: This program would be a voluntary Best Management Practice. The economic returns from implementing optical leak detection should motivate producers to implement

them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.
B. Indicate the most appropriate agency(ies) to implement: EPA and the state environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option
A. Technical: Several of these systems are commercially available.
B. Environmental: The environmental benefits of using optical imaging to detect and repair leaks have been documented. Companies reporting to EPA have reduced emissions significantly. Individual company results can be found on the EPA Natural Gas Star Program web site referenced below.
C. Economic: EPA reports that optical leak detection surveys pay for themselves in less than a year.
Differing opinion: Must be evaluated for each operation, may not be economic or applicable for all.

IV. Background data and assumptions used
See the web site for EPA's Natural Gas Star Program: http://www.epa.gov/gasstar/index.htm

Individual companies' experience with optical imaging leak detection:

Dynergy: http://www.epa.gov/gasstar/pdf/ngstar_fall2005.pdf

Enbridge: http://www.epa.gov/gasstar/workshops/houston-oct2005/dodson.pdf

Also see the agendas from the 2003 – 2005 Gas STAR Program annual implementation workshops: http://www.epa.gov/gasstar/workshops/imp_workshops.htm

Information on the ANGEL-DIAL technology:
http://www.epa.gov/gasstar/workshops/kenai/itt_sstearns.pdf

http://www.epa.gov/gasstar/pdf/ngspartnerup_spring06.pdf

Texas Commission on Environmental Quality report that includes comparison of various imaging technologies: http://www.tceq.state.tx.us/implementation/air/terp/Prop_02R04.html

V. Any uncertainty associated with the option Low. This is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None known.

Mitigation Option: Convert Gas Pneumatic Controls to Instrument Air

I. Description of the mitigation option

This option would encourage oil and gas producers and pipelines to convert pneumatic controls from natural gas to compressed instrument air systems. It would enhance EPA's current efforts in the Natural Gas Star Program and make them specific to the San Juan Basin. This would result in a significant reduction in methane emissions as well as achieve cost savings for the companies.

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. As part of normal operation, natural gas powered pneumatic devices release or bleed gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. The constant bleed of natural gas from these controllers is collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 24 billion cubic feet (Bcf) per year in the production sector, 16 Bcf from processing and 14 Bcf per year in the transmission sector. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network.

Companies can achieve significant cost savings and methane emission reductions by converting natural gas-powered pneumatic control systems to compressed instrument air systems. Instrument air systems substitute compressed air for the pressurized natural gas, eliminating methane emissions and providing additional safety benefits. Cost effective applications, however, are limited to those field sites with available electrical power.

In compressed instrument air systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. All other parts of a gas pneumatic system work the same way with air as they do with gas. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system.
Reducing methane emissions from pneumatic devices by converting to instrument air systems can yield significant economic and environmental benefits for natural gas companies including:

- Financial Return from Reducing Gas Emission Losses. In many cases, the cost of converting to instrument air can be recovered in less than a year.
- Increased Life of Control Devices and Improved Operational Efficiency
- Avoided Use of Flammable Natural Gas. By eliminating the use of a flammable substance, operational safety is significantly increased.
- Lower Methane Emissions
-

The conversion of natural gas pneumatics to instrument air system is applicable to all natural gas facilities and plants where an electric power supply is available. For those sites that do not have electricity available, cost savings and methane emissions reductions can still be achieved by replacing high-bleed pneumatic devices with low bleed devices, retrofitting high-bleed devices, and improving maintenance practices. Experience has shown that these options often pay for themselves in less than a year.

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary. The economic returns from implementing instrument air or low bleed systems should motivate producers to implement them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.
B. Indicate the most appropriate agency(ies) to implement: EPA and the state environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option
A. Technical: These systems are off-the-shelf and proven. Best utilized at larger facilities.
B. Environmental: The environmental benefits of replacing high-bleed pneumatic controls with instrument air, in terms of lower methane emissions, have been documented by EPA. Companies reporting to EPA have reduced emissions by an average of 20 Bcf per year per facility.
C. Economic: EPA reports that instrument air systems pay for themselves in less than a year. Replacing or retrofitting high-bleed units with low-bleed units have a payback of five months to one year.
Differing opinion: May not be economically justifiable or operationally sound for small facilities and well sites.

IV. Background data and assumptions used
See the web site for EPA's Natural Gas Star Program: http://www.epa.gov/gasstar/index.htm

In particular, the lessons learned summaries for instrument air:
http://www.epa.gov/gasstar/pdf/lessons/ll_instrument_air.pdf

And for low-bleed pneumatics:
http://www.epa.gov/gasstar/pdf/lessons/ll_pneumatics.pdf

V. Any uncertainty associated with the option Low: this is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None known.

EXPLORATION & PRODUCTION: MIDSTREAM OPERATIONS

Mitigation Option: Application of NSPS and MACT Requirements for Existing Sources at Midstream Facilities

I. Description of the mitigation option

Overview

- This mitigation option would involve filling in the gaps where the NSPS and MACT fail to adequately regulate sources at midstream facilities. Filing in the gaps could include lifting exemptions on existing sources and lowering applicability thresholds. Specific examples include:
    - Subjecting existing stationary combustion turbines at midstream facilities to 40 CFR Part 63, Subpart YYYY;
    - Requiring existing 2 stroke lean burn and 4 stroke lean burn reciprocating internal combustion engines to meet 40 CFR Part 63, Subpart ZZZZ MACT standards at midstream facilities;
    - Requiring boilers, reboilers, or heaters with a design capacity of less than 10 mmBtu/hr to meet NSPS at 40 CFR Part 60, Subpart Dc at midstream facilities;
    - Requiring all midstream facilities to meet the requirements to 40 CFR Part 60, Subpart KKK; and
    - Requiring all amine sweetening units at midstream facilities to meet 40 CFR Part 60, Subpart LLL requirements.

  This option would involve case-by-case assessments of midstream facilities to determine whether additional pieces of equipment should be regulated under NSPS and MACT standards and to assess the feasibility of such regulation. The overall goal is to use NSPS and MACT standards as guides for further air pollution reductions at midstream facilities.

Air Quality/Environmental

- This mitigation option would lead to further reductions in hazardous air pollutants and criteria air pollutants by subjecting more units to regulation. By requiring more facilities and/or units to comply with NSPS and MACT, there may be an incentive to upgrade to cleaner equipment, which would provide additional air quality benefits.

Economics

- There would likely be additional costs associated with bringing previously unregulated facilities and/or units into compliance.
- The option may provide an incentive to replace older, less efficient equipment, which could lead to increased efficiency.
- There would be potential paybacks associated with methane recovery by complying with NSPS at Subpart KKK.

Tradeoffs

- None.

Burdens

- The burden would be on industry to bring facilities and/or units into compliance with the NSPS and MACT standard. Air quality impacts would be reduced, reducing burden on health and welfare. Regulatory agencies may have to revise rules to implement this mitigation options.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory. NSPS and MACT standards work best as mandatory requirements.
B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies, EPA.

III. Feasibility of the option

A. Technical: There will need to be case-by-case assessments, but this appears to be a technically feasible option.
B. Environmental: No environmental feasibility issues are known.
C. Economic: There may be economic concerns that should be addressed, but this option is not infeasible based on economics. The goal is clean air and that may take an investment.
D. Other: There will likely need to be rule changes to implement this option that may present feasibility issues.

IV. Background data and assumptions used

Background data and assumptions used came from review of EPA NSPS and MACT standards.

V. Any uncertainty associated with the option (Low, Medium, High):

Low uncertainty. The NSPS and MACT provide a solid basis for air pollution control options. However, further discussion and comments may reveal other means of using NSPS and MACT standards to keep air pollution in check.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups: None.

Mitigation Option: Specific Direction for How to Meet NSPS and MACT Standards: Directed Inspection and Maintenance

I. Description of the mitigation option

Overview

Meeting NSPS and MACT standards at Midstream facilities can often be achieved using a variety of methods, some of which may be better than others. For example, the EPA is proposing to allow the use of infrared cameras to meet Leak Detection and Repair (LDAR) requirements set forth in several NSPS and MACT standards. 70 Fed. Reg. pp. 17401-17409. The EPA has indicated that infrared cameras can provide better data than Reference Method 21.

This mitigation option provides specific direction on how to meet NSPS and MACT standards so that the best methods of compliance are met. Specifically, it requires operators to use approved infrared cameras to meet LDAR requirements set forth at 40 CFR Part 60, Subpart KKK and 40 CFR Part 63, Subpart HH and HHH.

It would also require operators to implement cost-effective options for reducing methane emissions, as outlined in Fernandez, et al. 2005, to meet applicable NSPS and MACT standards. These cost-effective options would vary depending on the equipment, but would include using vapor recovery units on tanks and dehydrators, using desiccant dehydrators rather than glycol dehydrators, replacing compressor rod packing after three years, replacing gas starters on compressor engines with air starters, and converting gas pneumatics at facilities to instrument air.

Air Quality/Environmental

- Meeting LDAR requirements using infrared cameras promises to better keep volatile organic compound and hazardous air pollutant emissions from leaking equipment in check. Implementing cost-effective options for reducing methane emissions will further reduce emissions. In both cases, methane emissions would be reduced, preventing further greenhouse gas emissions.

Economics

- This mitigation option will most likely yield a payback due to the recovery of methane. According to one case study, BP recovered $2.4 million in 2 months simply by recovering over 123 MMcf/yr of that was lost due to equipment leaks (see, http://www.epa.gov/gasstar/workshops/hobbs72706/dim.pdf).

Tradeoffs

- The use of some cost-effective methane control options may require the use of electricity, such as vapor recovery units, which may be generated through coal or natural gas burning. Potential increases in emissions from electricity generation could be prevented through the use of solar or other renewable energy sources.

Burdens

- The only burden would be the restriction of flexibility for the operators and the investment cost.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory. Although infrared cameras and methane control options can provide paybacks and are proven cost-effective, they are not widely used. Despite potential paybacks, current incentives do not appear to be strong enough to encourage their use. Mandatory requirements would provide that incentive.

B. Indicate the most appropriate agency(ies) to implement: State air quality agencies and EPA.

III. Feasibility of the option

A. Technical: Feasible, these technologies are already in use and are being implemented elsewhere.
B. Environmental: Vapor recovery units may require additional space at midstream facilities and could pose additional environmental impacts. This seems to present a limited environmental feasibility issue.
C. Economic: Given the paybacks from methane recovery, there are no economic feasibility issues.
D. Other: The EPA has not yet finalized its proposal to allow infrared cameras to be used solely to meet LDAR requirements in the NSPS and MACT.

IV. Background data and assumptions used

Background data was obtained from information on the EPA's Natural Gas Star Program website, www.epa.gov/gasstar, from the EPA's proposal to allow infrared cameras to be used to meet LDAR requirements at 70 Fed. Reg. 17401-17409, and from the Fernandez et al. 2005 paper, "Cost Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers," available online at http://www.epa.gov/outreach/gasstar/pdf/CaseStudy.pdf.

V. Any uncertainty associated with the option

Low uncertainty, especially with regards to the use of infrared cameras as effective tools to comply with NSPS and MACT LDAR requirements. Operators would still have to show that cost-effect methane control options would meet the applicable requirements of the NSPS and MACT.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups

Possibly the Cumulative Effects Group due to indirect emission increases from coal or natural gas burning plants that may accompany increased use of vapor recovery units or other methane control options requiring electricity.

OIL & GAS OVERARCHING

Mitigation Option: Lease and Permit Incentives for Improving Air Quality on Public Lands

I. Description of the mitigation option
This option would provide incentives in the form of exceptions or waivers from lease stipulations or permit conditions of approvals (COAs) for oil and gas drilling on public lands in exchange for a program of environmental mitigation activities that would reduce air emissions along with other types of environmental and ecological impacts.

Differing Opinion: The proposed activities that would reduce air emissions and surface disturbance in this section should become standard practices **but without** the proposed exchange for the exceptions or waivers from seasonal wildlife restrictions which would negatively impact public lands wildlife.

This option could provide incentives in the form of expedited permit processing for operating permits in exchange for a program of environmental mitigation activities that would require documented reductions in emissions from major and minor sources. This option is not intended to reduce protection for wildlife. Monitoring and adjustments in response to monitoring results would be used to assure that the package of mitigation activities and associated development does not adversely affect wildlife.

Differing Opinion: Additionally these incentives would not include the exception of waivers from lease stipulations or permit conditions of approval ("COAs") for oil and gas drilling on public lands.

Expedited operating permit issuance from the appropriate agency in exchange for additional emissions reductions offers incentives for both industry and the agencies

Industry Incentives include:

- The streamlining of operating permits.
- Direct and prompt cooperation with permit issuing agency.
- Obtaining an operating permit at an accelerated rate allows for an accelerated startup date, thus increased resource production (may be especially helpful for minor source operating permits).

Environmental Incentives include:

- The addition of emission control equipment such as a catalyst, Zero Emissions (a.k.a. Quantum Leap) Dehydrator, directional drilling, complying with emission limitations relating to hours of operation, lean burn engine, and/or implementing a program of environmental mitigation activities that would reduce air emissions.

This option would work well in the areas that smaller agencies, such as Tribes, oversee the operating permits. This option would be implemented by the applicable permitting agencies.

It would be modeled after the experience in the Pinedale Anticline and Jonah fields in Wyoming where producers face seasonal limitations on drilling due to concerns about wildlife impacts. As a result, drilling is prohibited for several months during the year, delaying development and increasing costs. Several producers have applied for and been granted permission to drill year round in exchange for efforts that mitigate environmental impacts. These efforts combine improved technologies and innovative practices that together greatly reduce adverse impacts. They include: directional drilling to reduce the number of drilling pads, and thus the amount of surface disturbance, by half or more; using natural gas-fired drilling rigs to reduce air emissions; transporting produced water by pipeline to eliminate truck trips;

using mat systems on drilling pads to reduce surface impact; partial remediation of drilling pads after the drilling phase; eliminating flares during well testing and completion to reduce air emissions and noise; centralized fracturing and production facilities; low impact road construction techniques; and produced water recycling. Producers and BLM will monitor wildlife impacts as part of the program. Year round drilling has the added benefits of reducing the duration of drilling operations by one third-to one-half, and increasing stability of the local community as workers move in with their families, rather than commuting seasonally.

Differing Opinion: This suggestion of modeling after the experience in Wyoming's Pinedale Anticline and Jonah fields fails to address the widespread and significant concerns that have been expressed regarding current and future impacts of oil and gas activity on wildlife in these fields and the wildlife population declines that have been documented through scientific studies. The Pinedale Anticline and Jonah field experience has not proven to be a model for wildlife, and recent proposals to increase drilling may even adversely impact a federally threatened species, the Bald Eagle, and further exacerbate problems for the sage grouse, a species which some believe should be listed as federally endangered because of recent population declines. Another report that helps put the Jonah field experience in perspective came in December 2006, stating that in places one well was being drilled per every five acres. Repeated concerns about the impact on wildlife in these areas of Wyoming have been expressed by numerous and diverse groups of people ranging from private citizens, outfitters, hunters, environmental organizations, scientists, to government agency personnel including personnel from Wyoming's Game and Fish Department. Drilling exceptions granted in crucial big game winter range around Pinedale early winter 2006/2007 were granted in the face of opposition by Wyoming's Game and Fish Department.

Differing Opinion Continued: Monitoring has also not been a model experience in this area. According to reports of a May 2006, internal assessment Pinedale, Wyoming, Bureau of Land Management field office, the office neglected its commitment to monitor and limit harm to wildlife and air quality from natural gas drilling in western Wyoming. A wildlife biologist who worked in that Pinedale office, Steve Belinda, is reported to have quit his job because he and other wildlife specialists were required to spend nearly all their time in the office processing drilling requests and were not able to go into the field to monitor the effect of the thousands of wells on wildlife.

This option would involve tradeoffs between seasonal restrictions, which would be relaxed, and a comprehensive wildlife and environmental impact plan which would use the kind of technologies and practices listed above. This plan would reduce impacts on wildlife, as well as on air quality, land and water resources, and on the local communities. Ecological and environmental monitoring would assess these impacts and allow for adjustments in the plans as activities proceed. All of these elements would be contained in agreements between the land management agencies and industry, with public input.

Differing Opinion: Exceptions or waivers from wildlife lease stipulations or permit conditions of approvals (COAs) for oil and gas drilling on public lands likely would increase negative impacts of oil and gas activities on wildlife in the Four Corners. At least in Northwest New Mexico and likely in the other Four Corners states, it is important to remember that the seasonal closures in the Bureau of Land Management Farmington Field Office management area exist only for parts of the year with their length dependent upon the animal species and the reason for the restriction such as elk calving or antelope fawning. The restrictions are in place to protect species during times of the year when they are especially vulnerable such as nesting for raptors; wintering for deer, elk, and Bald Eagles; and birthing and caring for young for antelope and elk. Provisions for waiving, excepting, or modifying the oil/gas lease stipulations already exist according to the Bureau of Land Management Farmington Field Office's 2003 Record of Decision for Farmington's Proposed RMP and Final Environmental Impact. These restrictions should remain in place to protect wildlife, especially with the current and anticipated intensity of drilling.

Differing Opinion Continued: An indication of the major potential for the impact of oil and gas activity on wildlife is found in the 2006 Annual Report of the Sublette Mule Deer Study conducted in the Pinedale Anticline Project Area. Study results that "suggest that mule deer abundance in the treatment area declined by 46 % in the first 4 years of gas development."

Differing Opinion Continued: In the summer, 2006, publication of the New Mexico Department of Game and Fish titled New Mexico Wildlife under the regional outlook for Northwest New Mexico, wildlife biologists are reported to be "concerned about the effects the severely dry spring had on fawn survival in the state's **already depressed deer herds**." [Bolding is this author's.]

Differing Opinion Continued: Removal of the wintering restrictions for mule deer could create problems in New Mexico and in both this state and Colorado where migratory populations are shared. Another word of caution is found in the Upper San Basin Biological Assessment in the Comprehensive Wildlife Conservation Strategy (New Mexico's wildlife action plan accepted by the US Fish and Wildlife Service in 2006), which places mule deer in its list of Species of Greatest Conservation Need in the Colorado Plateau Ecoregion. Under "Problems Affecting Habitats or Species" in Chapter 5 of this document is this statement: "Of particular concern are energy development…" along with invasive species and livestock grazing practices. The document states that "coal bed methane development in the San Juan Basin is currently a major land use…Depending on the scale, density, and arrangement of each well site in relation to other sites, habitat loss and fragmentation in the portions of this habitat type [Big Sagebrush Shrubland] subjected to energy development are extensive. At this high level of development, effects may not be successfully mitigated."

Differing Opinion Continued: Pronghorn antelope numbers were so low at the time the Farmington Field Office's Draft Pronghorn Antelope Habitat Management Plan was published in March 2004, that the populations were described as struggling to survive, a change from when this species was common in the 1950's and 1960's. The restriction of drilling and construction activity during antelope fawning period from May 1 through July 15 was proposed as one of the ways to bring the populations back to eventual self-sufficiency.

These actions reduce air emissions from drilling rigs, from trucks (both diesel emissions and road dust), and from flaring. There are also benefits from reduced surface impacts and improved water management, as well as improved community stability.

Differing Opinion Continued: The actions that are offered that will reduce air pollution appear to be important ways to address our air quality problem and should become required practice because of the serious air pollution problems in the San Juan Basin. They should not come at an expense to area wildlife, which is already negatively impacted by direct and functional habitat loss due to oil and gas activities, as delineated in the 2003 Bureau of Land Management Farmington Field Office Draft Resource Management Plan and Environmental Impact Statement.

This option would work well in areas of the Four Corners region where new oil and gas projects are being proposed and where those projects face access limitations from wildlife stipulations or COAs. In these cases, the land management agencies (principally the BLM and the Forest Service) would have the greatest opportunity to negotiate agreements for infrastructure and operational changes from project start, in exchange for relaxing the access restrictions, along with monitoring for wildlife impacts. Monitoring of the air quality impacts, including documentation of reductions over similar projects without mitigation, would be required.

In New Mexico, this option could be integrated with the New Mexico Oil and Gas Association's (NMOGA) Good Neighbor Initiative.

Differing Opinion: Year round drilling will not improve air quality. The current drilling seasons are in place to protect the wildlife in the area. The improved technologies and innovative practices described above should be standard industry requirements and not be used in trade for expanded drill seasons.

Differing Opinion: BLM should not entertain compromising one environmental value in exchange for protecting another when industry is legally mandated to protect both. Year round drilling will only add to the stress wildlife currently experience in an already highly fragmented habitat. Even more, in the San Juan Basin industry has demonstrated their reluctance to routinely employ directional drilling as a means to avoid further habitat fragmentation. Since directional drilling "all wells" would be the cornerstone of the proposed mitigation option it seems that this options would not be favorably received by industry.

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary and would rely on the operators, the agencies, and any local communities obtaining benefits from the arrangements.
B. Indicate the most appropriate agency(ies) to implement: BLM and the Forest Service on Federal land. State and tribal land management agencies may implement this option on state and tribal lands.

III. Feasibility of the option

A. Technical: The technological approaches to reducing impacts are already being implemented in Wyoming and other locations.
Differing Opinion: Four Corners states should use the technological approaches without industry cost being a factor.
B. Environmental: The environmental benefits of the mitigation measures are currently being documented in Wyoming. Many of them seem apparent. The impact of year round drilling (or other permit-related incentives) on wildlife would have to be closely monitored.
C. Economic: Many environmental mitigation measures turn out to be economically attractive as well (e.g., natural gas drilling rigs can reduce fuel costs by two-thirds). Year-round drilling can shorten the project length by one-third to one-half, improving project economics. Producers would have to anticipate an economic benefit in order to enter into agreements.

IV. Background data and assumptions used

Web sites and presentations from operators and BLM on the experience with this kind of agreement in Wyoming. The NMOGA web site has information on their Good Neighbor Initiative.

See the following web sites:
BLM environmental assessment of year-round drilling in the Pinedale Anticline Field:
http://www.wy.blm.gov/nepa/pfodocs/questar/01ea.pdf
(See especially section 2.5 on Applicant-Committed Mitigation.)

Questar presentation on development in Pinedale:
http://www.wy.blm.gov/fluidminerals04/presentations/NFMC/028RonHogan.pdf\

BLM assessment of year round drilling demonstration project in the Pinedale Anticline Field:
http://www.wy.blm.gov/nepa/pfodocs/asu/01ea.pdf

Jonah Infill Project:
Encana release: http://www.encana.com/operations/upstream/us_jonah_blm.html
BLM air quality discussion:
http://www.wy.blm.gov/nepa/pfodocs/jonah/92FEISAirQualSuppleQ-As.pdf
BLM EIS and Record of Decision: http://www.wy.blm.gov/nepa/pfodocs/jonah/

NMOGA Good Neighbors Initiative:
http://www.nmoga.org/nmoga/NMOGA%20Good%20Neighbor%20Initiative.pdf
Wyoming Mule Deer Study Report (1 site)
http://www.west-inc.com/reports/big_game/PAPA_deer_report_2006.pdf
Wyoming wildlife, sage grouse
http://stream.publicbroadcasting.net/production/mp3/wpr/local-wpr-563699.mp3
http://gf.state.wy.us/downloads/pdf/sagegrouse/Holloran2005PhD.pdf
Wyoming wildlife, Bald Eagle http://www.wy.blm.gov/nepa/pfodocs/anticline/seis/06chap3.pdf 3-97
http://www.wy.blm.gov/nepa/pfodocs/anticline/seis/07chap4.pdf 4-123
Wyoming Bureau of Land Management, wildlife monitoring (1site)
http://www.washingtonpost.com/wp-dyn/content/article/2006/08/31/AR2006083101482.html
New Mexico: Comprehensive Wildlife Conservation Strategy (CWCS)
http://fws-nmcfwru.nmsu.edu/cwcs/New_Mexico_CWCS.htm
New Mexico—2003 Bureau of Land Management Resource Management Plan/Environmental Impact Statement, Record of Decision http://www.nm.blm.gov/ffo/ffo_p_rmp_feis/docs/Farmington_ROD.pdf Appendix B

V. Any uncertainty associated with the option
Medium: Depends on opportunities (proposed projects) for implementing incentives in exchange for mitigation activities, on producer willingness to participate, and on BLM/FS state and regional office and tribal policy.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups Impacts from trucks and roads may overlap with the Other Sources work group.

Mitigation Option: Economic Incentives-Based Emission Trading System (EBETS)

I. Description of the mitigation option

The central idea of this option is that inherent economic incentives promote innovative ways to achieve emission reductions, including gains from efficiencies in operation and maintenance and in applications of new innovative engine and control technologies.

This option encourages the use of pollution markets through implementation of an emission trading system (ETS) along with cooperative partnerships to reduce air emissions with the aid of emission reduction incentives. Basically in an emission trading program, the governing authority (e.g., agency) issues a limited number of allocations in the form of certificates consistent with the desired or targeted level of emissions in an identified region or area. The sources of a particular air pollutant (e.g., NOx) are allotted certificates to release a specified number of tons of the pollutant. The certificate owners may choose either to continue to release the pollutant at current levels and use the certificates or to reduce their emissions and sell the certificates. The fact that the certificates have value as an item to be sold or traded gives the owner an incentive to reduce the company's emissions. Simply stated in an ETS, a producer who has low-emission engines could sell emissions credits to a producer who has high-emission engines. Typically, 0.8 units of credit could be sold for each unit of reduction below the standard or reference level. The end result is a ratcheting down of overall emissions. This option does not contemplate multi-pollutant trading, but rather a separate market for each individual pollutant.

Approximately 30 state and federal ETS programs existed or were being developed in the U.S. in the later part of the 1990s. Examples of ETS that have worked reasonably well in achieving emission reductions and providing economic incentives to industry include the Illinois EPA's Emission Reduction Market System (ERMS), Indiana Department of Environmental Management's credit registry trading system, U.S. EPA's Acid Rain Program, and commercial and non-commercial institutions like Chicago Climate Exchange (CCX). In addition, in 2002 the US EPA approved a plan submitted by the WRAP, which contained recommendations for implementing the regional haze rule. The plan included an SO_2 emissions allowance trading program for nine Western states and eligible Indian tribes. As an example, EPA's program took about three years to plan and begin implementing.

The proposed economic incentives based emission trading system (EBETS) mitigation option can be developed or modeled after ETSs which have been successful and tailored to issues specific to the Four Corner region. Emission credits can accrue through a variety of methods that are complementary to or independent of other mitigation options developed herein by the Task Force. For example, credits can be gained through use of partnerships that that provide incentives for voluntary emission reductions, such as in the EPA's Natural Gas STAR Program or New Mexico's VISTAS program (see the IBEMP mitigation option paper, OOP4). Credits for use or sale (e.g., sales within the ETS) can also be acquired through use of tax and/or lease incentives and through the initiatives coming from Small and Large Engine Subgroup (e.g., advanced ignition systems, use of electric engines, centralized large engine from many small engine mode of operations). In addition, opportunities exist for collaboration between engine manufacturers and producers for field testing new engine technology through a swap out program, dirty old for cleaner new. Finally, use of voluntary laboratory testing of a select group of existing engines (e.g. uncontrolled small, <300 hp, engines) could provide a means to identify innovative cost-effective modifications to improve engine efficiency and reduce engine emissions (SERP, 2006).

<u>Benefits</u>: Joint participation by oil and gas, electric power production, and other source category stakeholders provides opportunities for multi-pollutant emission reductions that cover key criteria air pollutants such as NO_x, SO_2, VOCs, $PM_{2.5}$, and PM_{10}. An added benefit could be realized by also including green house gases such as CO_2 and CH_4, in the mix. Examples of the emission reductions that

could be achieved by a well designed and implemented ETS are the 50% reduction from 1980 levels of SO2 emissions from utilities under the ETS within US EPA's Acid Rain Program[1] and the 65% reduction from 1990 levels achieved under the Ozone Transport Commission NOx Program (SERP, 2006).

Tradeoffs: The ETS could be designed to provide for pollutant emission allocation and/or credit tradeoffs (e.g., NOx for SO2 in NOx limited regions) and trades between source groups or categories (e.g., oil and gas NOx with power plant SO_2).

Burdens: The major burden would be administrative in nature. Who would be responsible for designing, setting up and administering the proposed EBETS program and how would it be funded?

II. Description of how to implement

A. Mandatory or voluntary: Participation in the program would be voluntarily.

B. Indicate the most appropriate agency (ies) to implement: The states.

III. Feasibility of the option

A. Technical: The technical feasibility of ETS programs is well established and is in use around the world.

   Differing opinion: Accurately and reliably measuring the emissions from oil and gas sources will prove challenging. EBETSs have had broad success because those that have been established rely heavily on good monitoring and reporting, and it is not clear that such techniques are available for the oil and gas sources of interest. Parametric, as opposed to direct exhaust emissions monitoring is one option, but the less direct/accurate/reliable the measurement, the more likely it is that some offset/discount will be demanded to make up for the uncertainty, e.g., if a source wanted to purchase credits as part of its compliance plan, it would have to purchase two instead of one. Alternatively, sources with relatively weaker emissions monitoring would be allowed to purchase credits, but not sell them. This latter approach was taken in the WRAP SO2 Backstop Trading Program.

B. Environmental: The feasibility in achieving significant emission reductions has been clearly demonstrated through use of well designed and implemented ETS programs. Inclusion and addition of "Best Management Practices," innovative technologies, improved maintenance and other pay-back incentives enhance the feasibility of achieving emission reductions required to meet air quality and visibility enhancement goals in the Four Corners Region.

C. Economic: This program is economically feasible because emission trading provides economic incentives through implementation of complementary voluntary measures that reduce emissions, provide fuel savings, reduce operation and maintenance cost by adoption of BMPs and installation of innovative technologies. One recent study of projected economic gain by 2010 from the continued implementation of the ETS within the Acid Rain Program estimated it would provide an annual economic benefit of $122 billion (in 2000 $) at an annual cost of approximately $3 billion (or a 1 to 40 cost-benefit ratio).

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[1] The success of the Acid Rain Program ETS is evident from emissions data, which shows that SO_2 emissions were reduced by over 5 million tons from 1990 levels or about 34 percent of total emissions from the power sector. When compared to 1980 levels, SO_2 emissions from power plants have reduced by 7 million tons or more than 40 percent.

IV. Background data and assumption used

1. United States Environmental Protection Agency (USEPA) Acid Rain Program < http://www.epa.gov/airmarkets/arp/index.html>
2. Illinois Environmental Protection Agency Emission Reduction Market System (ERMS) <http://www.epa.state.il.us/air/erms/>
3. Argonne National Laboratory, Strategic Emission Reduction Plan, Draft, 2006.
4. Chicago Climate Exchange < http://www.chicagoclimatex.com/>

V. Any uncertainty associated with the option Medium to high.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups
A key crossover issue to establishing and implementing an effective EBETS is the facilitation of voluntary participation of electric utilities and other major source groups. This will provide the anticipated needed trade-offs in air pollutants (e.g., NOx and SO_2) that participation by one or a limited number of source groups may not be able to provide.

Mitigation Option: Tax or Economic Development Incentives for Environmental Mitigation

I. Description of the mitigation option

This option provides for regulatory agencies and industry working together to utilize various legislative (state/federal/tribal) processes to achieve real emissions reductions. Emission reductions would be achieved by providing economic incentives that would encourage the industry to utilize lower emission internal combustion engines in various applications.

Emission reductions could be achieved through reducing the number of trucks in the field. This could be accomplished by providing incentives for companies to install underground piping in order to dispose of produced water. Criteria pollutants could be reduced by installing lower emissions compressor engines. Industry could be encouraged to install such engines by implementing tax incentives as described below.

Tax incentives provide economic relief to industry by reducing or eliminating taxes on certain equipment or activities. The equipment or activity must provide a recognized environmental benefit to the taxing entity that grants the incentive. Some examples of tax incentives currently being utilized are: (1) allowing costs of retrofitting existing engines or installing new engines to be fully deducted in the year they are incurred rather than being capitalized (2) tax credit certificates issued to program participants, which can be redeemed over a specified period of time (3) income tax credits upon installation of approved equipment.

The air quality benefits include net reduction of emissions, primarily of nitrogen oxides. However, reductions in sulfur oxides, greenhouse gas emissions and particulate matter emissions can also be calculated. Only positive environmental impacts have been identified. It is not anticipated that this strategy would cause any negative impacts, other than increased costs to industry. This strategy specifically provides for relief from such economic impacts.

Economic burdens include the cost to the oil and gas industry, engine manufacturers and other interest groups to develop and lobby legislative proposals. New technology would be more efficient, possibly resulting in increased production and reduced costs. The increased revenue would provide some offset to the initial costs of installation or retrofitting. Economic burden to the taxing entity would also occur. The taxpayers would, in effect, be subsidizing industry efforts to install or retrofit equipment to achieve lower emissions. Achieving taxpayer approval for such a subsidy might prove difficult.

Assistance from the Cumulative Effects Work Group could be helpful in estimating the potential cost-benefit of this option.

II. Description of how to implement

A. Mandatory or voluntary: Participation by industry or other groups would be voluntary, both in working to establish tax/economic development incentives and in taking advantage of such incentives.
B. Indicate the most appropriate agency(ies) to implement**:** States of Colorado and New Mexico. Counties of San Juan, NM; La Plata, CO; and other counties in the Four Corners area of impact. Indian tribes, including Jicarilla, Ute Mountain Ute, Southern Ute, Navajo, and others. These groups would need to work with state legislatures and/or Congressional representatives in getting sponsors to help draft an energy bill that includes tax incentives for improving Four Corners air quality.

III. Feasibility of the option

A. Technical: Many models of tax and economic development incentives are available. A list of some models follows, with more details contained in an Appendix to this document.

i. Mineral Tax Incentives and the Wyoming Economy, May 2001, is an economic model. http://legisweb.state.wy.us/2001/interim/app/reports/mineraltaxincentives.htm

ii. Brownfields Tax Incentive (1997 Taxpayer Relief Act P.L. 105-34). This model allows costs to be fully deductible in the year they are incurred, rather than having to be capitalized.

iii. New York State Green Building Initiative. This tax credit program was developed by New York State Department of Environmental Conservation as per 6NYCRR Part 638. Tax credit certificates are issued and can be redeemed at any time over a designated period (i.e. 2006 – 2014).

iv. Montana Incentives for Renewable Energy include property tax exemptions, industry tax credit, venture capital tax credits, and a low interest revolving loan program, special revenue local government bonds, and streamlined permitting processes for participants, income tax credits for retro-fitting equipment.

v. State of Virginia House Bill 2141, July 1997 allows the local governing body of any county, city, or town, by ordinance, to exempt, or partially exempt property from local taxation annually for a period not to exceed five years.

vi. US EPA's Voluntary Diesel Retrofit Program is a non-regulatory, incentive-based, voluntary program designed to reduce emissions from existing diesel vehicles and equipment by encouraging equipment owners to install pollution reducing technology. This option would easily fit into the "partnership" mitigation option. However, it is also a model for the type of equipment that might qualify for a tax incentive.

vii. Philippines Department of Natural Resources developed a single document that consolidates all tax incentives for air pollution control devices. Not new incentives, but a compilation of existing programs.

viii. Western Regional Air Partnership diesel Retrofit program for diesel engines could be used as a model for other internal combustion engines. The guidance document for developing a retrofit program is found on the WRAP website. See Appendix for information. This option would easily fit into the "partnership" mitigation option. However, it operates similar to a tax incentive program and gives an example of how to set up a workable program.

B. Environmental: The environmental benefits of pollutant emissions reductions are well documented.

C. Economic: The entire concept of this mitigation option is that it must be economically viable.

IV. Background data and assumptions used

See Appendix for background studies.
Cooperation between the regulated community; local, state and tribal governments; and equipment manufacturers would have to be garnered in order for this option to work.

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option

The three member drafting team expressed no disagreement with this option.

VII. Cross-over issues to the other source groups

These tax incentive programs could also apply to other sources, such as power plants or vehicles.

APPENDIX

Mineral Tax Incentives and the Wyoming Economy, May 2001, is an economic model. http://legisweb.state.wy.us/2001/interim/app/reports/mineraltaxincentives.htm
This model can be used to show the effects of all tax incentives previously granted, as well as the effects of hypothetical tax incentives or tax relief that might be considered in the future. Impacts include reduction in taxes; increased production; effects on federal, state and local government revenues.

Brownfields Tax Incentive fact sheets (EPA 500-F-03-223, June 2003) and incentive guidelines (EPA 500-F-01-338, August 2001) can be found on US EPA's website at www.epa.gov/swerosps/bf/bftaxinc.htm There are also numerous case studies listed on this site as well as federal resources.

New York State Green Building Initiative credit certificates can be re-allocated to secondary users, if the initial recipient cannot utilize the entire credit amount. Information available at www.dec.state.ny.us/website/ppu/grnbldg/index.html or Pollution Prevention Unit (518) 402-9469; NY business tax hotline (518)862-1090 x 3311

Montana Incentives for Renewable Energy http://deq.mt.gov/Energy/Renewable/TaxIncentRenew.asp

Virginia property tax exemptions for the Voluntary Remediation Program http://www.deq.state.va.us/vrp/tax.html

US EPA's Voluntary Diesel Retrofit Program information at http://www.epa.gov/otaq/retrofit/retroverifiedlist.htm Includes a list of approved retrofit technology.

Philippines Department of Natural Resources lists many tax incentive and economic incentives at http://www.cyberdyaryo.com/features/f2004_0624_03.htm Also included are numerous links to related sites.

Western Regional Air Partnership guidance document for diesel retrofit programs can be found at http://www.wrapair.org/forums/msf/offroad_diesel.html

Mitigation Option: Voluntary Partnerships and Pay-back Incentives: Four Corners Innovation Technology and Best Energy-Environment Management Practices (IBEMP)

I. Description of the mitigation option

This option encourages establishment of partnerships between oil and gas producers and federal, state and local agencies and with engine manufacturers. Examples of such voluntary partnerships that have worked successfully in reducing emissions and providing cost benefits to industry include the U.S. EPA's Natural Gas STAR Program, the New Mexico's Voluntary Innovative Strategies for Today's Air Standards (VISTAS) Program, Green Power and Combined Heat and Power Partnerships. The Natural Gas STAR Program is one of many voluntary programs established by the U.S. Environmental Protection Agency (EPA) to promote government/industry partnerships that encourage cost-effective technologies and market-based approaches to reducing air pollution. There are seven San Juan Basin producers[1] that are currently active members of the Natural Gas STAR Program. The VISTA Program is modeled after Natural Gas STAR.

This option involves establishing new partnerships or extending existing partnerships that encourage voluntary measures that reduce emissions and provide industry payback through improved operation and maintenance efficiencies. The IBEMP option is based on and is intended to extend upon the successes achieved in EPA's Natural Gas STAR Program and to complement the newly established VISTAS Program.

The central ideas of this option

- Increasing efficiency will result in more productivity, less emission, and increased revenue.
- Complementing EPA's Natural Gas STAR Program and VISTAS program to focus on the pollutants not covered in these programs
- Collection and use of the Best Management Practices (BMPs) from around the world, latest innovative technologies, and innovative solutions found by IBEMP members.

The air quality benefits include reduction of criteria pollutants such as NOx, SO_2, $PM_{2.5}$, PM_{10} as well as green house gases CO_2 and CH_4. The success of the EPA's Natural Gas STAR Program is well documented. According to the EPA's Gas Program, "Since the Program's launch in 1993, Natural Gas STAR Partners has eliminated more than 220 billion cubic feet (Bcf) of methane emissions, resulting in approximately $660 million in increased revenues." One Natural Gas STAR Partner has achieved the 18% to 24% fuel saving and reduction of 128 Mcf of methane emission per unit per year after installing an automated air to fuel ratio (AFR) control system called REMVue. According to engine manufacturers, new generation engines have benefits over older generation such as low operating cost, high thermal efficiency, low emissions, maintenance simplicity, and low repair cost which will help in recovering the cost of investment faster. An example of rapid improvement in the engine technology is the new Cummins-Westport engine, which is capable of peak thermal efficiency of close to 40% with 0.01 g/bhp-hr PM and 0.2 g/bhp-hr NOx emission. Even though Cummins-Westport engines and new generation engines from other engine manufacturers are geared towards transportation sector at present because of tighter emission standards, the improved engine technologies will help reduce the pollution in the other industrial sectors as the demand grows for efficient engines.

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[1] BP, Burlington Resources, ConocoPhillips, Devon Energy, Williams Production, Energen Resources, and XTO Energy

Under this option, the time period to offset the cost of the replacing old engines with a new generation engines can be estimated through analysis of data from laboratory testing. Such data may be available from engine manufacturers or obtained through independent laboratory engine performance tests. The voluntary comparative laboratory performance and emissions testing (e.g., operating cost) and documentation would be performed by an independent test laboratory. In addition, voluntary laboratory and field-testing of a select group of existing engines (e.g., uncontrolled small, < 300 hp, engines) could provide a means to identify cost-effective modifications to improve engine efficiency and reduce engine emissions (Lazaro 2006, SERP).

Under this program the increased revenue from methane mitigation and fuel and maintenance savings can offset the cost of investment in the BMP and new technologies or equipment. In addition, under the proposed IBEMP option, partner members' mitigation efforts will be fully recognized and promoted similar to the recognition of partner contributions under EPA's Natural Gas STAR Program and New Mexico's VISTAS Program. Mitigation efforts can be recognized through awarding of emission credits (which can be traded in an emission market system, OOT-3). These efforts will also provide benefits to members through improved public and investor relations.

Since the IBEMP option is a voluntary program, participating members will have control or choice on mitigation decisions that are made. This provides opportunities for choices that provide a return on investments in best management practices and on new equipment and technology. As such, this option does not impose a burden on participating partners. Although, being a partner under this option would not relieve an operator from complying with non-voluntary measures or options, BMPs or other commitments made voluntarily under this option may facilitate compliance with other mandatory measures that may be adopted or come into play.

II. Description of how to implement

A. Mandatory or voluntary: The participation in the program is voluntarily

B. Indicate the most appropriate agency(ies) to implement: Through the New Mexico Environment Department under or a part of its VISTAS Program and/or in partnership with the Colorado Department of Public Health and Environment. The USEPA Gas Program may also be interested in collaborative partnerships with the Four Corners Air Quality Task Force.

III. Feasibility of the option

A. Technical: The success of the EPA's Natural Gas STAR Program is a clear indicator of the technical feasibility of this program.
B. Environmental: The Best Management Practices, including equipment upgrades are well established in the oil and gas industry and adoption of these measures will provide opportunities for significant and achievable emission reductions.
C. Economic: This program is economically feasible because innovative technologies and BMPs will result in increased productivity, fuel saving, and environmental benefits, which in return offset the cost of investment. The previously referenced EPA Natural Gas STAR Program example illustrates that significant savings can be achieved in reduced fuel consumption (e.g., in one case that covered 51 engines reduction in excess of 2,900 MMcf or an average of 78 Mcf per day per engine, when adjusted for load, was achieved over a two-year period). The final payout period was 1.4 years by taking into consideration of fuel saving of $4.35 million at a nominal value of $3/Mcf.

IV. Background data and assumptions used

1. United States Environmental Protection Agency (USEPA) Natural Gas STAR Program <http://www.epa.gov/gas/>

2. New Mexico San Juan Voluntary Innovative Strategies for Today's Air Standards (VISTAS) <http://www.nmenv.state.nm.us/aqb/projects/SJV/index.html>
3. Engine Manufacturers: <www.cat.com>, <www.cummins.com>, <www.cumminswestport.com>.
4. Argonne National Laboratory, Strategic Emission Reduction Plan, Draft, 2006
5. Near-term commercial availability of small clean efficient engines
6. Near-term commercial availability of advanced engine technology

V. Any uncertainty associated with the option Low to medium.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

Establishing and implementing an effective IBEMP is the facilitation of voluntary participation of San Juan oil and gas producers. There are no key crossover issues with other source groups.

Mitigation Option: Voluntary Programs

<u>I. Description of the mitigation option</u>

Overview
This option describes voluntary programs to implement mitigation strategies and achieve air quality benefits that are above and beyond the requirements of regulations and permits. This option is not meant to replace the *Voluntary Partnerships and Pay-back Incentive* mitigation option, nor is this option meant to indicate voluntary implementation should be applied to existing or future requirements necessary for improvement of air quality. There are situations in which mandatory measures are the only system that will result in emissions reductions that are high-impact, consistent, and necessary. There are also situations in which voluntary implementation of strategies may be a method to achieve emissions reductions in a time- and cost-effective manner. Voluntary programs allow participants to demonstrate their commitment to the issue and to local communities. Challenges to success with voluntary programs include publicizing a program to make it well-known, creating a list of strategies and technologies that may be implemented voluntarily, offering incentives sufficient to attract program participants, and quantifying emissions reductions adequately and consistently to estimate results.

Air Quality and Environmental Benefits

- Air quality improvement because voluntary measures would achieve emissions reductions beyond regulatory and permitting requirements.
- Depending on strategy/technology, other environmental benefits may exist.

Economic

- Capital investment from participants for voluntary measures and reporting.

Trade-offs

- Air quality improvement
- Positive public relations
- Agency's costs for administration and tracking.

<u>II. Description of how to implement</u>

A. Mandatory or voluntary: Voluntary. The New Mexico Environment Department already administers a voluntary program called VISTAS (Voluntary Innovative Strategies for Today's Air Standards) that is modeled after EPA's Natural Gas STAR Program. To increase implementation, the agency could compile of list of mitigation options not otherwise required by regulation or permit, as a list of "qualifying" voluntary measures for VISTAS. More information about VISTAS is available at: http://www.nmenv.state.nm.us/aqb/projects/SJV/index.html. Quantification of benefits and measurement of other results is essential to ensure accountability in a voluntary program and increase likelihood of success of the program. In addition, participants or the administrator of a voluntary program should describe voluntary actions by producing "Lessons Learned" papers, which are short descriptions of practices and technologies employed, benefits and challenges, feasibility, and implications for future use of the same voluntary actions.
B. Indicate the most appropriate agency(ies) to implement: State Environmental Agencies

<u>III. Feasibility of the option</u>

A. Technical: Good feasibility due to flexibility and choices regarding participation and specific technology(ies) implemented. Potential voluntary measures for the oil and gas industries may include, but are not limited to, the following:

- Plunger lift cycles for removal of liquid buildup and minimizing well blowdowns.
- Device on tanks to control over-heating, such as bands of insulation.
- Electrification where possible.
- Centralization of tank batteries to decrease truck traffic.

B. Environmental: Excellent feasibility, however environmental benefits depend on control strategies. Select control strategies may have other air or non-air environmental impacts, such as SCR's ammonia slip.

C. Economic: Feasibility depends on incentives. Economic feasibility often increases in response to incentives. Participation in voluntary programs for companies is often based on a cost/benefit economic analysis, and incentives can provide a deciding factor. Potential incentives would be determined by the implementing agency and may include the following:

- "Good Citizen" marketing
- Alternative to regulation, if any exist
- Paybacks/savings
- Consideration for expedited permits, if possible
- Parametric monitoring less strict or other requirement leniency, if possible
- Tax credit/royalty rate reduction
- For Federal land, modification in standard stipulations, if possible.
- "Credit" given like an Environmental Management System on compliance history

IV. Background data and assumptions used
Natural Gas STAR and San Juan VISTAS, both voluntary air programs in the Four Corners region.

V. Any uncertainty associated with the option High. Voluntary programs do not guarantee emissions reductions, nor are emissions reductions enforceable. Quantify of reductions through reporting may lessen uncertainty but do not guarantee or enforce reductions.

VI. Level of agreement within the work group for this mitigation option Medium. This option write-up stems from a discussion at the November 8, 2006 meeting of the Oil and Gas Work Group.

Some members of the work group expressed concern that mandatory application of the strategies outlined in this document prior to analysis by a regulatory agency may preclude consideration of advantages and disadvantages from voluntary programs. There was also some discussion of the concept of criteria for establishing whether a mitigation strategy is applied under voluntary or mandatory conditions should be developed to enhance capability for implementation of the options. These criteria would provide an important tool to agencies considering options by better defining feasibility. Additionally, voluntary application of the mitigation strategies would facilitate the development and efficient implementation of these options via a "lessons learned" approach where mandatory application may prematurely dictate the method of implementation.

VII. Cross-over issues to the other source groups
If a voluntary program has a wide range of participants, there are many cross-over issues to other source groups in terms of what voluntary measures could be implemented by those sources.

Mitigation Option: Cumulative Inventory of Emissions and Required Control Technology

I. Description of Mitigation Option

The Four Corners Region is a hotbed of oil and gas activity. There are more than 20,000 oil and gas wells in the San Juan Basin and at least 12,500 additional new wells are proposed within the next 20 years. Oil and gas facilities are being located in remote areas and in neighborhoods and cities. The City of Bloomfield, NM, population of 7,200 people, has at least six major oil and gas processing facilities in very close proximity. A large elementary school near the cluster of these facilities north of Bloomfield was evacuated in 2006 due to an accidental release of noxious emissions from one of these gas plants.

A cumulative inventory of total emissions from the large oil and gas facilities near densely populated areas should be conducted prior to the permitting of additional facilities. It has been reported that at least one new, large, petroleum processing facility is on the drawing board for the Bloomfield area.

All oil and gas facilities, large or small, should be required to report all emissions to appropriate governing agencies annually. A cumulative inventory of emissions is necessary.

Installation of best available technology emission control equipment on ALL oil and gas facilities should be MANDATORY to greatly reduce the release of pollutants into the environment. All internal combustion engines should be required to be fitted with catalytic converters.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory.

B. Indicate the most appropriate agency (ies) to implement: States of New Mexico and Colorado.

III. Feasibility of the option

A. Technical: is not clear whether the intent was to have a yearly report of emissions output based on continuous emissions monitoring for all pollutants (very expensive), or if the intent was to have the operators estimate the amount of emissions based on what sources had been operational during the year. Option also needs to define what levels of the given pollutants would be acceptable to assess feasibility.
B. Environmental: None
C. Economic: None

IV. Background data and assumption used

Bloomfield area ozone levels are already periodically high according to monitoring. Any consideration of permitting additional large oil and gas facilities near Bloomfield should include risk of increasing levels of ozone.

An example:
The North Crandall Compressor Station located within the City of Aztec is permitted by NMED Air Quality Bureau at 176.3 tons/yr (tpy) of Nitrogen Oxides (NOX), 39.4 tpy of Carbon Monoxide and 75.9 tpy of Volatile Organic Compounds (VOC's). There is a warning sign on the fence that states "Warning Hazardous B.T.E.X. emissions may be present." B.T.E.X. compounds are toxic to humans and wildlife. Several homes are located near this facility.

In comparison to the refineries and gas processing facilities in the Bloomfield area, the Williams Crandall Compressor Station is small but it is permitted to emit about 292 tons of pollutants per year into the atmosphere. Cumulative permitted emissions from the very large Bloomfield facilities are unavailable at this time.

Oil and gas facilities are sources of many hazardous pollutants such as NOX, SOX, VOC's, methane, hydrogen sulfide, etc. Many of these pollutants contribute to respiratory diseases, cardiac diseases and some of them are carcinogens. Hydrogen sulfide is a deadly neurotoxin.

V. Any uncertainty associated with the option None.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups TBD.

Mitigation Option: Mitigation of Hydrogen Sulfide

I. Description of Mitigation Option

Hydrogen sulfide (H2S) is a deadly neurotoxin. Since H2S contamination is becoming more widespread, for the safety of the public and the oilfield employees ALL wells should be tested for H2S by the well operators at least twice per year and the test results reported to appropriate agencies.

The companies provide H2S training and monitors for the employees. The employees are trained to be aware of H2S, but the general population is not. The typical rotten egg smell is a familiar warning to oilfield employees, but the general population who lives in close proximity to H2S wells are not informed about the dangers of an H2S release.

Public information programs on the dangers and toxicity of oil and gas pollutants and most importantly H2S, must be made available to the people. Ideally, gas wells and refineries should be isolated away from the general population; however, oil and gas facilities are being established in populated areas and vice versa. Houses are being built next to oil and gas sites. For the health of the public, exposure to H2S and other petroleum related toxics must be prevented.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory.

B. Indicate the most appropriate agency (ies) to implement: The companies and the States of New Mexico and Colorado.

III. Feasibility of the option

Not considered.

IV. Background data and assumption used

For H2S information, do a Google search on Dr. Kaye H. Kilburn MD, and Professor of Medicine at the University of Southern California. He is a leading researcher on chemicals such as hydrogen sulfide and diesel exhaust.

The Bureau of Land Management has been collecting data on the wells contaminated by hydrogen sulfide in the San Juan Basin.

Quick statistics are as follows:

- More than 375 wells test positive for H2S
- H2S is present in at least 5 formations
- 11 producers have reported H2S wells
- A lot of the small producers did not report, so these numbers are likely higher.

Sour gas (H2S) fields are common in Colorado and New Mexico. New Mexico has a State Regulation with an ambient air quality standard for H2S; however, it is reported that NMED does not have H2S measuring equipment. H2S must be closely monitored and controlled by the companies and the State and Federal agencies. It can be deadly.

V. Any uncertainty associated with the option TBD.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups TBD.

Mitigation Option: Encourage States Importing San Juan Basin Natural Gas to Require Pollution Control at the Source

I. Description of the mitigation option

States that import San Juan Basin natural gas should require the gas be produced and transmitted in an environmentally clean method. End users should have a responsibility for the sources of pollution generated from natural gas production.

Recent California legislation banning importation of power from sources that generate more greenhouse gases than in-state natural gas-fired plants leads to this related issue.

Much of the natural gas used in these plants as well as in the residential sector is imported from other states or other countries. One published article[1] states that 85% of the natural gas used in California is from out-of-state and that one-quarter of this comes from the San Juan Basin. Other states may also be using San Juan Basin natural gas. It is disingenuous for states to claim to be producing clean power or using clean gas for residential use when the production of fuel for that "clean" power plant or clean burning appliance is creating serious air and water quality problems at the source of the fuel. If the user states are seriously concerned about improving air and water quality they should address out-of-state impacts as well as in-state impacts.

II. Description of how to implement

A. Mandatory or voluntary:
   Adoption of a "clean fuel import policy" by user states would necessarily have to be voluntary. However, the application of such a policy by a user state, once adopted, could and should be mandatory for fuel importers.

B. Indicate the most appropriate agencies to implement:
   Implementation of the policy in user states could be by the regulatory agencies or commissions charged with oversight of investor-owned or publicly-owned electric utility systems. In some cases legislation may be necessary to implement this policy.
   There is a need to develop an inventory, state-by-state, of customers who are importing natural gas from wells in the San Juan Basin. The first step in implementation would involve contacting user states and urging adoption of policy or legislation requiring importation of "clean" natural gas; a definition of "clean" must be developed.

III. Feasibility of the option

A. Technical:
   It may be difficult to develop a good working definition of what constitutes acceptably "clean" natural gas. This is also a legal issue and one must work within the framework of the Federal Clean Air Act and Clean Water Act as well as individual state statutes.

B. Environmental:
   Should be feasible

C. Economic:
   Could eventually lead to higher costs for electricity in user states due to the rightful inclusion of environmental costs of fuel production.

D. Political:
   Could be very difficult to implement in some states

IV. Background data and assumptions used

Assumption that most natural gas produced in the San Juan Basin is exported to other states. The figures cited in Section I should be checked/verified.

V. Any uncertainty associated with the option
Yes; response of user states unknown.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups
Significant cross-over to the Power Plants and Oil & Gas Work Groups

[1] *High Country News*, Dec. 25, 2006, p. 12.

OIL & GAS: PUBLIC COMMENTS

Oil & Gas Exploration & Production Public Comments

Comment	Mitigation Option
If "many companies BMPs in place already," then why does a mandatory approach to BMPs seem implausible. This should be a cost of doing business in this area; a cost that is well-absorbed by most other companies.	Best Management Practices (BMPs) for Operating Tank Batteries
VRU's have one big technical problem not addressed, the introduction of air in the gas. Air is made up of Nitrogen and Oxygen two contaminates that the gas pipeline companies refuse to take into their system. If one VRU allows air to enter the gas system, then the whole gas system must be shut down or flared in the field. The gas companies must be forced to take air in reasonable quantities into their system. The gas pipelines will argue that it is unsafe, if that is true then all the gas supplying houses in the Colorado front range must be shutdown because air is added to improve quality.	Installing Vapor Recovery Units
In the 60's and 70's this type of water removal was tried in the northern Rockies. The amount of saltwater disposal was huge and the beds may only last a day or two before they must be changed.	Dehydrators / Separators / Heaters
Glycol pumps are a critical item and any replacement system must have a high reliability. 5KW generators will had NOx, CO, CO2 and decrease reliability. Kimray pumps with flash gas separators reduce emissions and keep the system reliable. the gases recovered from the pump gas separator can be used for fuel MOST of the time. In some cases where the gas stream is high in liquefiable hydrocarbons (those with molecular weights higher than 40) the pump gas separator vapors will not burn reliably or completely cause unreliable operators and increased emissions. In the case of gases with high liquefiable content, vent gases need to be flared (burned).	Zero Emissions (a.k.a. Quantum Leap) Dehydrator
We strongly agree that an initial voluntary monitoring effort, followed by mandatory reporting and monitoring requirements, should be initiated by the operators to measure concentrations and species of VOCs and HAPs and other flaring by-products.	Venting versus Flaring of Natural Gas during Well Completions
We strongly agree that co-location and centralization of new oil/gas field facilities should be voluntarily implemented by operators. We also agree with the approach of state and federal agencies and mineral management agencies proactively integrating this approach into planning and permitting processes.	Co-location / Centralization for New Sources
The present laws will not allow this option. TEG (glycol) units must be permitted at a maximum rate. In the Rockies the maximum rate is only required for a few months during the year. Good operators adjust their pumps as needed to save fuel and lower emissions, but they get not credit for doing so because their permits are set. GLYCALC uses all kinds of default assumptions, this does not replace good engineering and the ability to make real life adjustments. Other design and simulation programs should be allowed without any legal ramifications.	Control Glycol Pump Rates
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Control Glycol Pump Rates
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Convert High-Bleed to Low or No Bleed Gas Pneumatic Controls
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Optical Imaging to Detect Gas Leaks

Comment	Mitigation Option
Instrument gas or instrument air is used to control facilities. These controls maintain the emission control system, gas quality controls and safety shutdown systems. If the instruments air/gas system lacks sufficient quantity and quality, the controls will fail and emissions, quality and safety devices can fail with undesirable results. At small and remote sites air compressors will be unreliable and gas must be used.	Convert Gas Pneumatic Controls to Instrument Air

Oil & Gas Stationary RICE Public Comments

Comment	Mitigation Option
The SUGF agrees that new air quality management strategies such as this option should be implemented to address cumulative air quality impacts. It is highly recommended that this option be considered by the regulatory agencies and be applied to both new and existing engines, particularly units of less than 300 horsepower. Although horsepower levels are lower and operating hours may be limited, emission rates of these smaller units are higher than larger units. As a single source, emissions may be minimal, but collectively with other area sources it may have a cumulative affect.	Industry Collaboration
Comments below are specific to the mitigation option as currently written, which assumes the power requirement would come from the power grid. A second alternative is also provided below as a sub option assuming the power comes from on-site generators. We recommend including both alternatives to this option. Comments are also provided on the analysis of this option under the cumulative effects section of the public draft report. Install Electric Compression (re-label as Alternative 1 - Power Grid, see recommended Alternative 2 addition below after comment # 6) 1. The overview is not consistent with overviews written for other mitigation options covered in the Task Force Report. As written, the overview presents a rather biased view on the viability of this option. The overview should provide a description of the option without any discussion about the option's technical or economic feasibility. Possible physical restriction or modification requirements on installation for specific compressors should be removed and discussed under Sec III. Feasibility of the option, A. Technical. The last two sentences on the electric grid should also be moved to the feasibility discussion or deleted. Under the mitigation option overview, we recommend inserting the following: The selection of combustion engines for electric compression should be on case-by-case basis which will allow the flexibility of evaluating necessary compressor interface modifications such as re-gearing to accommodate electric motors. 2. The discussion and emission table under Air Quality/Environment is inconsistent with discussions covered in the other mitigation options and should be deleted. Please see our comments on the Cumulative Effects section analysis of this option. The nationwide averages of emissions from power plants operated by the three identified companies would not be representative of the power supplied from the Western Power Grid. We recommend inserting the following under the mitigation option overview:	Install Electric Compression

Comment	Mitigation Option
The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation. 3. The economics as written only covers the costs of the option if implemented. To provide a balance picture both costs and economic benefits should be covered. The following points should be included in the discussion: a. In case of electric motors connected to power grid, there is virtually no maintenance cost. b. The electric rates in the night are cheaper compared to peak times. This will result in additional saving for oil and gas industry. c. The need for less maintenance of electric motors and localized electric grid will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well as minimize impact on the wild area in the four corners region. In the second bullet not sure what specific maintenance and repair costs we be borne by producers that are associated with the electric power source for electric compression. Maintenance and repair of substations and transmission lines, from the grid to substation, are typically borne by electric generators and included in rates to consumers. The last bullet on suppliers/manufacturers is more an implementation issue than an economic issue. We recommend moving this discussion to description on how to implement. 4. Tradeoffs - We recommend striking any reference to new co-generation plants as means to supply power for electric compression, since the electric compression option requires no thermal power. As previously stated current plans for electric power generating within the western regional power grid should be adequate to meet even the most optimal electric compression demand that might develop. 5. Burdens - Since implementation of electric compression is voluntary the producers can evaluate which compressor conversions to electric are economically feasible. Economic burdens over the long term can be minimized and possibly turned into economic gain based on careful evaluation of return on capitol expenditures (e.g., lower electric motor vs. RICE engine maintenance costs). The assumed requirement for new electric power generation to support electric compression is speculative, since the degree of implementation of this option producer specific. We recommend deleting the sentence on capitol investment for new power plants. Also, existing plans for new generation may be sufficiently adequate to meet reasonably anticipated power requirements for implementing this option. We recommend consultation with the Power Plant Workgroup. 6. II. Description of how to implement and feasibility of option - See above comments. 7. III. Feasibility of the option, C Economics - On economics, we agree that costs need to be evaluated, including the economic benefits, as previously mentioned. The need for modeling (air quality) to evaluate the air quality	

Comment	Mitigation Option
benefits is true about all of the options. Also, the planned modeling to address cumulative regional air quality impacts is discussed elsewhere in the draft report. We recommend deleting the sentence. ON-SITE ELECTRIC GENERATOR ALTERNATIVE TO GRID POWERED ELECTRIC COMPRESSION As written the current option identifies only one source of electric power, power from the grid. A second alternative to this option would be to supply power to the electric motors using local dedicated low-emission natural gas lean-burn electric generators. The electric compression using the lean-burn electric generator should be included as a second alternative for the "Install Electric Compression" mitigation option. We recommend that the Four Corners Air Quality Task Force add the following language to the Install Electric Compression mitigation option: Mitigation Option: Install Electric Compression (Alternative - On-Site Generators) I. Description of the mitigation option Overview - As an alternative to grid power dedicated on-site natural gas-fired electrical generators can be used to supply power to electric motors that replace the selected RICE compression engines. The electric motors would be rated at an equivalent horsepower to that of RICE engines currently used for gas compression. The power sources for the electric compression could consist of a network of on-site gas-fired electrical power generators. The alternative could be expanded to include consideration of replacement of other engines, such as, gas-fired pump-jack engines used as "prime-movers." The currently available gas electric generator run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural and field gases. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. Decisions on the use of on-site generators to replace natural gas-fired engines and the number of generators required would depend on a number of factors, including the proximity, spacing and size of existing engines. As a simple example using the conversion factor of 1 MW = 1,341 HP, adding a 1 MW natural gas-fired generator could replace an inventory of approximately 33 small (40 hp) internal combustion engines if these were reasonably close proximity, say spaced within a one or two mile radius. However, in "real world" operations, there will be several factors involved in determining the number of required gas-fired electrical generators; such as transmission loss, ambient operating temperature, load operating conditions, pattering of applied loads, etc. Air Quality/Environmental Benefits The emissions from gas electrical generators are relatively low compare to smaller internal combustion engines because of new technology and ability of controlling emission from big engines. For example a Caterpillar G3612 gas electrical generator with power rating of 2275 kW emits 0.7 gram/hp-hr NO_x at 900 rpm which is equivalent to 0.0009387 g/W-hr. For comparative illustration with alternative 1, if you assume …. As stated in the mitigation	

Comment	Mitigation Option
option; "Control Technology Options for Four Corners Power Plant" (FCPP), the NOx emission from FCPP is approximately 0.54 g/mmBtu. Based on the assumption that efficiency of FCPP is 40%, the NOx emission from FCPP is approximately 0.002099 g/W-hr. This comparison shows that the gas electrical generator is more environmentally friendly then using power from a coal based power plant. The baseline average emission for the Western Grid should be used to calculate the real emission difference between installing a lean burn electric generator to replace combustion engines. The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation. The need for less maintenance of electric motors and lean burn electric generator will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well minimize the impact on wild area in the four corners region. Economics The initial capitol cost of installing gas electrical generator and electrical motor would be relatively high. As an example, a generator of 1 MW capacity can approximately support 33 combustion engine of 40 HP. A general purpose 40 HP engines costs about $1200.00 which results in capital cost of $39,600 for replacing 33 internal combustion engine with electric motors. The approximate cost of a 1.2 MW gas-fired generator is $430,000. The total capital cost for replacing 33 engines with a gas fired generator will be about $470,000. However in long term the benefit in terms of emission reduction and saving in maintenance cost should help in recovering the initial capital cost. The maintenance cost of one big generator is cheaper than maintenance of many smaller internal combustion engines. The cost of running electrical wires to connect electric motors will much less than currently installed pipelines to carry natural gas for the small rich burn combustion engines. Tradeoffs In case of gas electric generators, there will be shift of emission from many internal combustion engines to one or several big internal combustion engine(s). There would be a net reduction in emissions which will depend on degree of conversion that each producer deems economically feasible. The cost and affects of running transmission lines from generator(s) to power electrical motors for gas compression needs to be evaluated. Burdens The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry. II. Description of how to implement	

Comment	Mitigation Option
A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time. B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies. III. Feasibility of the option A. Technical: The feasibility mainly depends on the close proximity of replaceable internal combustion engines and operating conditions of internal combustions engines in order of selection of gas electrical generator. The power, transmission line and substation requirements for on-site lean-burn generator system would need to be carefully considered in deciding the feasibility of this option. B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Emissions from on-site electric generators would more than off-set the natural gas-fired engines that could be targeted for replacement (e.g., uncontrolled compressor engines or small rich burn pump jack engines). C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site. Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small. IV. Background data and assumptions used The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff. Gas electrical generator information was obtained from Caterpillar's Website. V. Any uncertainty associated with the option (Low, Medium, High): Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies. VI. Level of agreement within the work group for this mitigation option TBD VII. Cross-over issues to the other source groups (please describe the issue and	
The SUGF agrees that implementation of this federally mandated level of emission control will minimize emissions from newly manufactured, modified and reconstructed engines after their respective effective dates.	Follow EPA New Source Performance Standards (NSPS)

Comment	Mitigation Option
The SUGF supports the control technology options listed above as the SUGF supports usage of Best Available Control Technologies on internal combustion engines located within the exterior boundaries of the Southern Ute Indian Reservation.	Use of SCR for NOx control on lean burn engines Use of NSCR / 3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines Use of Oxidation Catalysts and Air/Fuel Ratio Controllers on Lean Burn Engines Install Lean Burn Engines
As EPA commented on the Cumulative Effects Paper, it is unclear how the 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE are being implemented. The mitigation option <u>Interim Emissions Recommendations for Stationary RICE</u> states that "BLM in New Mexico and Colorado are currently requiring these emission limits as a Condition of Approval (COA) for their Applications for Permits to Drill (APD). These limits currently apply only to new and **relocated** engines ... (compressors assigned to the well APD)..." However, we understand that BLM policy for a small engine COA as applied to an APD is for new and **replacement** engines. The Oil and Gas Workgroup should clarify how is the terms "relocated" and/or "replacement" are being defined by BLM and the USFS with respect to COAs for well located engines. For comparison, EPA's NSPS for spark ignition engines will apply to new, modified, and reconstructed units starting in January 2008. The terms new, modified, and reconstructed are defined in Federal Regulation.	Interim Emissions Recommendations for Stationary RICE
We recommend adding the following next generation technology to the four currently included in this mitigation option: Homogeneous-Charge Compression-Ignition (HCCI) technology was analyzed the by cumulative effects workgroup but was inadvertently omitted from the oil and gas work group mitigation option paper Next Generation RICE Stationary Technology. The following is a recommended text for inclusion in the Final Report: Homogeneous-Charge Compression-Ignition (HCCI) Engine I. Description of the mitigation option Overview Homogeneous charge compression ignition (HCCI) engines are under development at several laboratories. In these engines a fully mixed charge of air and fuel is compressed until the heat of compression ignites it. The HCCI combustion process is unique since it proceeds uniformly throughout the entire cylinder rather than having a discreet high-temperature flame front as is	Next Generation Stationary RICE Control Technologies – Cooperative Technology Partnerships

Comment	Mitigation Option
the case with spark ignition or diesel engines. The low-temperature combustion of HCCI produces extremely low levels of NOx. The challenge of HCCI is in achieving the correct ignition timing, although progress is being made in the laboratories.[1] Only a few experimental measurements of NOx from (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.[2] Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.[3] The achievable NOx emission levels are yet to be determined. It is not currently known if HCCI technology can be applied to all engine types and sizes. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option. II. Description of how to implement A. Mandatory or voluntary It is too early to determine whether implementation of this technology will be voluntary or mandatory. B. Indicate the most appropriate agencies to implement III. Feasibility of the option A. Technical - HCCI is in the laboratory stage of development. B. Environmental - HCCI has the potential of extremely low NOx levels. C. Economic - HCCI is not sufficiently developed to have proven economic feasibility. IV. Background data and assumptions used 1. Bengt Johansson, "Homogeneous-Charge Compression-Ignition: The Future of IC Engines," Lund Institute of Technology at Lund University, undated manuscript. 2. Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc. 3. Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002. V. Any uncertainty associated with the option (Low, Medium, or High) HCCI has high uncertainty.	

Comment	Mitigation Option
VI. Level of agreement within the work group for this mitigation option VII. Cross-over issues to the other source groups (Please describe the issue and which group.)	

Oil & Gas Overarching Issues Public Comments

Comment	Mitigation Option
The Four Corners Air Quality Task Force (4CAQTF) is a noble way of beginning communication between our citizenry and the polluting industries. Hopefully some meaningful "common ground" can be reached that will produce measurable air quality improvements. With a demonstrated failure of industry to "want to do their best" and when the "dollar gain" in a corporation's quarterly report is the measuring stick for it's shareholders, the recommendations from the 4CAQTF is up against a mature lobby force very capable of stopping meaningful actions that will lead to measurable benefits to our air quality! Therefore, spending serious time deliberating measurable benefits that could predictably occur if industry's suggestion of "year round" drilling EVERYWHERE as a means of ameliorating their emissions to me, seems without merit. A simple catalytic converter on each of their established fossil fuel operated engines would be considered a "wonderful start" of industry wanting "to do their best". Recommending to any state or federal land wildlife management agency to consider removing established seasonal habitat protection bans for the assumed benefit of distributing annual air quality pollutants should not be an option. Many years were spent by land management and wildlife management agencies formulating the habitats that need protection for identified species. The process to establish habitat closures is elaborate. Let us let this industry recommendation respectfully die and encourage installation of catalytic converters on industry's fossil fuel motors. This action does have measurable air quality results. As we drivers know, we are required by law to have catalytic converters on our vehicles as a way of demonstrating our contribution to improving air quality problems. As a recommendation, I would only suggest that if the oil and gas industry wants to recommend the lifting of this seasonal closure on identified lands, that THEY contact the state and federal agencies that have programming prerogatives over habitat and wildlife issues with their suggestion that lifting this ban would have beneficial measurable benefits for air quality concerns that outweigh wildlife concerns. The 4CAQTF should not be the "quarter back" for carrying the recommendation to state and federal habitat and wildlife agencies. I make these comments as a degreed wildlife biologist with 27 years of experience. Respectfully, Warren J. McNall 900 Sabena, Aztec, NM	Lease and Permit Incentives for Improving Air Quality on Public Lands

Comment	**Mitigation Option**
Disagree - unlike Wyoming, Colorado has a shortage of state and federal specialists to monitor impacts from oil and gas development. As a result, monitoring of oil and gas impacts to wildlife would likely not happen. Streamlining the permit process would be beneficial to operators economically, but may be at the expense of area wildlife and habitat.	Lease and Permit Incentives for Improving Air Quality on Public Lands
Regarding the paragraph: "Monitoring has also not been a model experience in this area. According to reports of a May, 2006, internal assessment Pinedale, Wyoming, Bureau of Land Management field office, the office neglected its commitment to monitor and limit harm to wildlife and air quality from natural gas drilling in western Wyoming. A wildlife biologist who worked in that Pinedale office, Steve Belinda, is reported to have quit his job because he and other wildlife specialists were required to spend nearly all their time in the office processing drilling requests and were not able to go into the field to monitor the effect of the thousands of wells on wildlife." Basically, I would suggest a more neutral approach than the quoted paragraph. It is rather forceful, without sufficient follow-up. It would help our situation if we could see whether the Farmington office is under similar pressures. Alternatively, examining the policies, rather than experiences, might make for a stronger position. For example, as the author seems to know a bit about BLM and permitting--she/he might instead look into the use of categorical exclusions (CAX) which are currently used to circumvent the environmental assessments (EA) that would normally be required to develop well fields on BLM land. (Sometimes this is also called streamlining.) How prevalent is this practice in the Four Corners, do CAX result in a lower standard of environmental review, and could this practice deleteriously impact 4C air quality?	Lease and Permit Incentives for Improving Air Quality on Public Lands
In light of the current global climate conditions, lessening our overall impact on the environment is everyone's duty to the planet and its children's future. This task force should not be in the position of negotiating away wildlife habitat in exchange for mitigating measures that ought to be a duty of the oil and gas industry as a cost of doing business on this planet.	Lease and Permit Incentives for Improving Air Quality on Public Lands
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Economic-Incentives Based Emission Trading System (EBETS)

Comment	Mitigation Option
Economic-incentives based emission trading systems (EBETS) have had varying levels of success nationally and have been less successful in geographic regions where pollutants are already causing harm to human health or the environment. It can also be argued that these systems lack incentives to improve environmental quality over economics. They can be more a function of market supply and demand driving the trades, not variations in regional human and environmental health "costs". Multisectoral trading systems are complex, increase challenges in emissions monitoring, and environmental justice considerations become more complicated due to inequitable concentrations of source emissions and different pollutant mixing outcomes. (Regarding the federal Acid Rain Program, indeed, the nationwide level of emissions from electric utilities were halved since 1980, however, no geographic restrictions were imposed and many areas of higher pollution levels remained at higher levels.) As stated in the Task Force document, the major burden for the EBETS mitigation option would be administrative; however the full burden must be assessed and coordinated among the state agencies. Not only would comparability and tracking of different types, sizes and ages of installations be extremely complicated, multi-pollutant emissions trading is challenging to monitor and enforce. Although it would be impossible to have an emissions trading system that eliminates environmental injustice, a carefully designed trading system that is rigorous, far-sighted, and includes geographic restrictions would have a much better chance of reducing localized injustices to human health and/or the environment.	Economic-Incentives Based Emission Trading System (EBETS)
The proposed incentive to modify standard stipulations for federal land if it is to be the relaxing or waiving of seasonal restrictions for wildlife while promoting year round drilling should not be a part of the voluntary program. Seasonal restrictions have been written to benefit wildlife during times of the year when they are at increased risk due to weather, nesting, birthing, etc. The Wyoming experience has shown the potential negative impacts of intense drilling on wildlife, and how highly wildlife is valued by a broad range of American people. With the pressures from the increase in drilling, wells, roads, and pipelines in the Four Corners area, we can ill afford to lose the wildlife protections from the stipulations that we currently have.	Voluntary Programs
New Mexico and Colorado already have rules governing H2S, no need to add more rules that may conflict.	Mitigation of Hydrogen Sulfide
New Mexico Environment Department does have controls for H2S on paper, but state environmental officials have validated that the state does not have H2S monitoring equipment.	Mitigation of Hydrogen Sulfide
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Mitigation of Hydrogen Sulfide
Rules that are capable of being enforced due to adequate staffing and necessary monitoring tools are what is needed to regulate this area. More rules that cloud the issue, or are effectively toothless due to lack of enforcement infrastructure will not accomplish the goals of this task force.	Mitigation of Hydrogen Sulfide

Power Plants

Power Plants: Preface

Overview

The Power Plants Work Group was charged with developing mitigation strategies for existing, proposed, and future power plants in the Four Corners area. For each strategy, one or more work group members provided a basic description of the strategy, ideas for implementation, and discussed feasibility issues to the extent possible.

Participation in the Power Plants Work Group included representatives from state, tribal and federal agencies; industry (including regional power plants); citizens; and interest groups. Ten to 20 participants attended each face-to-face meeting throughout the process. In total, the Power Plant Work Group brainstormed a total of 36 mitigation options and drafted 34. In addition, work group members helped in drafting 18 mitigation options for the Energy Efficiency, Renewable Energy and Conservation section.

Organization

The Power Plants work group initially collected information on existing emissions inventories and emissions projections for existing and proposed power plants. A spreadsheet, called Four Corners Area Power Plants Facility Data Table**,** is located at the end of the Power Plants section and was used as a tool to help supplement mitigation options papers with emissions reduction estimates. The work group divided the remainder of its work into the following categories.

Existing Power Plants: The work group first considered existing power plants, focusing on the two largest power plants in San Juan County: San Juan Generating Station (1800 MW) and Four Corners Power Plant (2000 MW). Eleven mitigation options were brainstormed and drafted for this section. The options drafted ranged from software applications and process optimization to retrofitting NOx and SO_2 emissions control technologies.

Proposed Power Plants: The work group next considered the proposed power plants category. The focus here was on the proposed Desert Rock Energy Project, a 1500 MW coal-fired power plant to be built in Burnham, 30 miles Southwest of Farmington. Options included funding of air quality improvement initiatives and consideration of the Integrated Gasification Combined Cycle (IGCC) process. Four of the 11 comments received on the Power Plants section of the Task Force Report during the public comment process were against building another power plant in the Four Corners area. Desert Rock also submitted comments on the Task Force report. Please see all the public comments pertaining to power plants in an appendix at the end of this section.

Future Power Plants: The work group discussed and documented eight strategies that future power plants could use to mitigate air pollution, including a carbon capture and sequestration (CCS) option, an option for clean coal incentives, large scale renewable energy production, and also an option on nuclear energy production.

Overarching Issues: Finally, the Power Plants report section also has an overarching category for options and ideas that may apply more broadly. Ten options were brainstormed and drafted here, and include mercury pollution mitigation and the Clean Air Mercury Rule (CAMR), cap and trade programs, greenhouse gas mitigation and one calling for a health study.

EXISTING POWER PLANTS: ADVANCED SOFTWARE APPLICATIONS

Mitigation Option: Lowering Air Emissions by Advanced Software Applications: Neural Net

I. Description of the mitigation option

There are many areas of power plant operation where Advanced Software Applications could lower air emissions from current levels. These processes range from the primary power generation equipment, to the various air pollution control devices (APCDs), such as scrubbers, precipitators, baghouses, and SCR units. The best gains in emission reduction couple state-of-the-art APCDs with advanced software applications operating within or in concert with the Distributed Control System, DCS. This mitigation option discusses Neural Network software to lower NO_x emissions at coal combustion low-NO_x burners. Other examples may be found in the Appendix.

Many power plant processes/devices, such as fan speeds, air damper positions, air and coal flows, are automatically controlled by the DCS. The DCS is a networked computer system with "distributed" input/output electronic hardware near the plant control devices, and "live" displays for the control room operators. Given the current state (on/off status or analog value) of every device tag in its database, the DCS uses feedback control algorithms to drive many controlled device variables. Set-points are optimized for the current desired mode of plant operation, such as satisfying a specified megawatt demand at the best possible heat rate.

Neural Networks offer advanced software control by "training" the software to "know" where outputs should be in relation to many inputs. Unlike traditional mathematical equation models, neural networks do not demand intimate understanding of the process. A neural network, sometimes referred to as "fuzzy logic," is a type of "artificial intelligence" statistical computer program, which classifies large and complex data sets by grouping cases together in a manner similar to the human brain. Neural networks "learn" complex processes by analyzing their performance data.

San Juan Generation Station (SJGS) is currently working with a predictive neural network on Units 1 and 2 to lower NO_x emissions. This advanced software application, provided by the DCS vendor, minimizes NO_x formation by optimizing air flow to the burners (e.g., optimal flame temperature). SJGS is gaining experience with this type of software, anticipating the installation of state-of-the-art low-NO_x burner hardware. When these burners are installed on all units, increased reductions in NO_x are anticipated. Neural network software results in lower NO_x emissions than if the burners were controlled by standard DCS software alone.

The neural network uses inputs from the NO_x and O_2 CEMS, Carbon Monoxide (CO) emissions, burner air, secondary combustion air, coal flow, flame temperature, fan speeds, damper positions, etc. There could be dozens of inputs. The network is trained to identify the relative contribution of each process input to NO_x formation as measured by the CEMS. The network is trained across varying modes of plant operation – full load, partial load, startup, etc. at the lowest possible NO_x emissions. Then, as the generating unit operates in various modes, the neural network predictions refine the control actions the DCS would take on its own. This refinement lowered NO_x emissions by approximately 25% at an Entergy coal fired plant (Intech, July 2006 – "Netting a Model Predictive Combo").
Note: CO_2 readings do not correlate significantly to NO_x control. Inputs from the NO_x, CO, and O_2 CEMS are used.

Benefits: NO_x reductions of 10% – 30%. Earn NOx Trading Credits as future regulations may require. Another important benefit is that tighter process controls from the neural network may improve the plant heat rate. When the heat rate improves, less energy is needed to maintain required MW load. With less associated stack gas volume for that load, all pollutant emissions decrease.

Trade-offs: Neural network cannot adapt to unforeseen upsets for which it was not originally trained. Neural net refinement control may have to be removed in these situations.

Some existing boiler controls may need to be automated so the neural network can act on them via the DCS. There are significant associated hardware, software, and labor costs. In combustion control schemes, optimizing NO_x for lowest emissions generally increases CO. CO emissions might increase because the neural network allows CO to ride very close to its regulatory limit. Without the network, CO is manually controlled to a lower level providing a cushion for upsets.

Software is processor-intensive.

Burdens: Cost of software application, more powerful computer hardware, "training" labor. Cost of upgrading some of the other controls on the boiler. The neural net is not much good unless it can actually adjust the equipment such as dampers, burner air registers, fan speed, etc. The controls have to be automated and have to be compatible with the neural net.

II. Description of how to implement

A. Mandatory or voluntary:

This option is being considered by San Juan Generating Station as part of consent decree to reduce NO_x emissions. It may be a viable option for FCPP. There may be some grants available to help fund such upgrades to existing power plants in Four Corners area.

FCPP has also installed neural networks and is gaining experience with process and emissions optimization. Desert Rock's potential use of this option is unknown.

B. Indicate the most appropriate agency(ies) to implement:

Federal, State, Tribal regulations should not specify specific control strategies, but rather impose emission limits reasonable for modern control strategies. Grandfathering of plants under NSR for installing enhanced controls, is another debate. However, if Federal NO_x budget trading is extended to this area under a Clear Skies option, the economic incentive of expensive NO_x trading credits to either buy or sell would encourage the final emissions control step of "advanced software applications" to realize optimum economic and environmental benefits.

Differing Opinion: Using NOx Budget trading and other grand fathering strategies do not address the pollution problems associated with old, out of date coal fired power plants. The Four Corners Power Plant is the top emitter of NOx in the Nation. Two coal fired power plants with high levels of emissions are located in the Four Corners. Grand fathering should not be an option. Extensive emissions clean up and control is necessary.

III. Feasibility of the option

A. Technical: Neural network technology is a viable control approach well established in many industrial process settings, but requires intensive computational capability. Powerful, cost-effective computers of recent years have facilitated growth of this technology. Due to some limitations to this control strategy, it takes its place with other advanced control strategies, such as Model Predictive Control.

B. Environmental: Environmental impacts are incidental, such as increased power consumption for more powerful computer hardware.
The point of this option is more efficient operation and thus lower emissions.

C. Economic: Software costs and labor are reasonable in light of the long term emission reductions attained. Generally, software costs are much less than capital expenditures for physical APCDs.

The Monitoring Work group asked if additional CEM or other technology be required to operate as part of the neural net feedback loop. SJGS and FCPP have existing NO_x CEMS to meet state and federal Acid Rain Program monitoring requirements. Acid Rain requires a high level of data quality assurance, including daily calibrations. A neural network continues to function upon loss of one or more inputs, within statistical limits. NO_x minimization control would continue during occasional loss of the NO_x CEMS input.

IV. Background data and assumptions used:
ISA Intech article
Information from San Juan Generating Station
There are many other sources of relevant information, including AWMA, Argonne, DOE.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups
Advanced Software Applications, including neural network control technology, could apply to sources in the Oil and Gas sector

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EXISTING: BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Mitigation Option: Control Technology Options for Four Corners Power Plant

I. Description of the mitigation option

Summary of Option

Presumptive Best Available Retrofit Technology (BART) emission limits for SO_2 should be applied to all units at Four Corners Power Plant (FCPP). Presumptive BART emission limits for NO_x should be applied to Units 1, 2 and 3; and combustion controls and Selective Catalytic Reduction (SCR) on Units 4 and 5. When BART for PM10 at FCPP is analyzed, the regulatory authority and the facility should consider the control level achieved at San Juan Generating Station.

Background: Best Available Retrofit Technology (BART)

The Four Corners Power Plant consists of five pulverized coal fired boilers. Each boiler was built between 1962 and 1977 and emits more that 250 tons per year of visibility-impairing pollution. The units are therefore subject to the Best Available Retrofit Technology (BART) requirements under the Regional Haze Rule. The BART requirements mandate industrial facilities that cause or contribute to regional haze to control emissions of visibility-impairing pollutants. The Clean Air Act (CAA) states that BART guidelines shall apply to fossil-fueled fired generating power plants with a capacity greater than 750 MW (§169A(b)). The CAA does not exempt individual units of any size from BART requirements.

For Electric Generating Units with a capacity greater than 200 MW, the Environmental Protection Agency (EPA) has provided (rebuttable) presumptive emission limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_x), based on boiler size, coal type and controls already in place. EPA "analysis indicates that these controls are likely to be among the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement." (70 FR 39131, July 6, 2005). Because the two smaller units (#1 & #2, each at 190 gross MW) are subject to BART and are close in capacity to EPA's 200 MW threshold, the rationale for applying presumptive limits should hold for those units as well. Those presumptive limits (which are 30-day rolling averages) are:

- Unit #1 is 190 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #2 is 190 gross MW dry bottom wall -fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #3 is 253 gross MW dry bottom wall -fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #4 is 818 gross MW cell-burner: 0.15 lb SO_2/mmBtu and 0.45 lb NO_x/mmBtu
- Unit #5 is 818 gross MW cell-burner: 0.15 lb SO_2/mmBtu and 0.45 lb NO_x/mmBtu

Background: FCPP Emissions

In the 1980s, Arizona Public Service (APS) installed venturi scrubbers on Units 1-3, and early generation spray tower scrubbers—but with significant stack gas bypass—on Units 4 and 5. In 2003, APS began a program to further reduce SO_2 emissions at FCPP by eliminating most stack gas bypass. APS succeeded in bringing emissions down from a 30-day rolling plant wide average of 0.44 lb/mmBtu in 2003 to 0.16 lb/mmBtu by 2005, with further improvement to 0.14 lb/mmBtu; this represents a removal efficiency of 92 percent. Although NO_x and PM_{10} emissions were not addressed in that effort, NO_x emissions have been reduced slightly, but FCPP is still the largest emitter of NO_x among coal-fired power plants nationwide.[1] The current rate at which FCPP emits NO_x is approximately 0.54 lb/mmBtu.

The FCPP is located on the Navajo Reservation, and was previously regulated by emission limitations set by the State of New Mexico. The Tribal Authority Rule, however, generally stated that state air quality regulations could not be enforced against facilities on the Indian reservation. EPA, therefore, has to issue federally enforceable emission limitations for FCPP. On August 31, 2006 EPA Region 9 proposed a Federal Implementation Plan (FIP) to establish federally enforceable emission limits for SO_2, NO_x, total PM, and opacity. The proposed FIP would require 88 percent removal of plant wide SO_2[2] on an annual rolling average basis. This would result in plant wide annual average SO_2 emissions being limited to 0.24 lb/mmBtu on coal projected to be burned in 2016.[3] The proposed FIP would require NO_x emissions not to exceed 0.85 lbs/mmBtu for Units 1 and 2, and 0.65 lbs/mmBtu for Units 3, 4 and 5.

The Four Corners Power Plant is located on the Navajo Reservation and the Tribal Authority Rule has stated that state air quality regulations could not be enforced against facilities on the Indian Reservation. It is imperative that a firm agreement between the Navajo Tribe and the Federal EPA be negotiated to guarantee that the Federal EPA will be the regulatory and enforcement agency for the Four Corners Power Plant (FCPP) clean up process. This will allow the Federal EPA to regulate and enforce emission limits for SO2, NOx, PMs and opacity that are specified in the new EPA Region 9 FIP.

Update: On April 30, 2007, EPA Region 9 finalized a Federal Implementation Plan (FIP) that establishes federally enforceable emission limits for SO_2, NO_x, total PM_{10} and opacity. The FIP requires 88 percent removal of plant wide SO_2 on an annual rolling average basis, and limits three-hour average SO_2 emissions to 17,900 lbs/hr plant wide. This would result in plant wide annual average SO_2 emissions being limited to 0.24 lb/mmBtu on coal projected to be burned in 2016. The FIP requires that 30-day rolling average NO_x emissions are not to exceed 0.85 lbs/mmBtu for Units 1 and 2, and 0.65 lbs/mmBtu for Units 3, 4 and 5; and daily NO_x emissions are not to exceed 335,000 lbs. PM emissions are limited to 0.050 lbs/mmBtu, and opacity is limited to 20%, except for one six-minute period per hour not to exceed 27%.

Presumptive BART at FCPP

Sulfur Dioxide

The application of presumptive BART limits for SO_2 on Units 1-5 at FCPP would result in a plant wide annual average of 0.15 lbs/mmBtu or 93 percent removal based on future coal. Estimated emissions for 2018[4] are shown in Figures 2 & 3 for emissions at the current level of control, the proposed level of control under the FIP, a scenario with BART applied to Units 3-5 only, and BART applied to Units 1-5. All options assume control efficiency remain constant within each given scenario.

Emissions under the scenario where presumptive BART for SO_2 is applied to all Units are only slightly less than current emission rates. However, applying presumptive BART for SO_2 would result in an emission limit specified as an allowable rate of emissions (lbs/mmBtu). The FIP would allow SO_2 removal to decline from the present 92 percent to 88 percent. Additionally, the FIP specifies the SO_2 limit in terms of efficiency, or percent removal of SO_2 from the coal being burned. If the coal quality decreases (to higher sulfur coal), as it is projected to do, the limit in terms of percent removal will allow for more emissions of SO_2; thus, it is preferable to have an emission rate as the controlling limit.

Nitrogen Oxides

The application of presumptive BART limits for NO_x on Units 1-3 (0.23 lb/mmBtu), and combustion controls and SCR on Units 4 & 5 would result in a plant wide annual average of 0.16 lb/mmBtu. Application of presumptive BART for Units 4 & 5 would result in a rate of 0.45 lbs/mmBtu for those Units. Estimated emissions for 2018 are shown in Figure 4 for emissions at the current level of control, the current Title V permit limit, the proposed level under the FIP, a scenario with BART applied to Units 1-5, and a scenario that applies BART to Units 1-3 and applies combustion controls and SCR to Units 4 & 5. NO_x emissions under the proposed FIP would be significantly higher than current rates; application of presumptive BART for NO_x to all Units would reduce NO_x 30 percent from current rates; application of presumptive BART to Units 1-3, and combustion controls plus SCR on Units 4 & 5 would result in the most significant reductions of NO_x: 70 percent from current rates, and less than half from the scenario with BART on all Units.

Since Units 4 and 5 are cell burners, they are inherently very high emitters of NO_x, and, because of the narrowness of their furnaces, are very difficult to reduce emissions by combustion controls alone (combustion controls alone represent presumptive BART). EPA has recognized that the presumptive limits (and associated technologies) do not preclude the application of different technologies: "[b]ecause of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. . . . Our presumption accordingly may not be appropriate for all sources."[5] The cost (see below) of SCR on these Units is comparable to combustion controls—which may not be technically feasible—and SCR will result in significantly more reductions of NO_x. Currently, Units 4 and 5 each emit twice the NO_x as Units 1, 2 and 3 individually.[6] Therefore, SCR is the best reasonable method to achieve meaningful NO_x reductions at Units 4 and 5.

Reduction of NO_x is particularly important to improve visibility at Mesa Verde National Park, which is 52 km away from FCPP. As shown in Figures 1a, 1b and 1c, visibility has degraded at Mesa Verde over the past decade, and the portion of degradation due to nitrate has increased (while there has been no trend in degradation due to sulfate).

II. Description of how to implement

A. Mandatory or voluntary:

This option represents a mandatory, federally enforceable emission limit.

B. Indicate the most appropriate agency(ies) to implement:

The regulating agency for this facility is EPA Region 9.

III. Feasibility of the option

FCPP is currently at or below the presumptive BART limit for SO_2. No additional controls are needed.
Differing Opinion: FCPP does not consistently operate at or below presumptive BART limit for SO_2

For Units 1-3, the Environmental Protection Agency's suggested presumptive BART for NO_x limits "reflect highly cost-effective technologies."[7] EPA, in fact, performed visibility impact and cost-effectiveness analyses on the presumptive limits. Therefore, the BART presumptive limits of NO_x are considered to be technical and economically feasible.

EPA states that the majority of units could meet presumptive NO_x limits with current combustion control technology for between $100 and $1000 per ton of NO_x removed. If more advanced combustion controls are required, the cost would be less than $1500 per ton of NO_x removed. Furthermore, EPA states that "by the time units are required to comply with any BART requirements . . . more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NO_x limits are conservative.[8]

Application of EPA's Cost Tool model for Units 4 & 5 predicts that NO_x could be reduced by 70% to the levels shown by application of combustion controls plus SCR at a cost of $409 - $464 per ton of NO_x removed.[9] EPA states that the average cost of combustion controls on cell burners (presumptive BART) is $1021 per ton. The average cost of applying SCR to cyclone units, (which for those units is presumptive BART), is $900 per ton.

IV. Background data and assumptions used

Historical emissions data comes from EPA's Clean Air Markets Division databases. Projected capacity utilizations come from the Western Regional Air Partnership's "11_state_EGU_analysis" projections.

EPA's cost tool: http://www.epa.gov/airmarkt/arp/nox/controltech.html

V. Any uncertainty associated with the option

Uncertainties in FCPP's ability to meet the BART presumptive limit for SO_2 include future coal quality. Future emissions of SO_2, NO_x and PM10 will depend on future utilization, which at this point has been predicted.

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups None.

Citations:

[1] http://cfpub.epa.gov/gdm/index.cfm?fuseaction=factstrends.top_bypollutant

[2] Although EPA limits annual average SO_2 emissions to 12.0% of the SO_2 produced by the plant's coal-burning equipment, its method of calculating the amount of SO_2 produced is not consistent with EPA's "Compilation of Air Pollutant Emission Factors," (AP-42) which assumes that 12.5% of the sulfur in sub-bituminous coal (as burned at FCPP) is never converted to SO_2 but is retained in the ash collected in the boiler. When this sulfur retention is taken into consideration, the EPA proposal represents 86% control of potential SO_2 emissions.

[3] BHP, the supplier of coal to FCPP, has projected coal quality to 2016 when its contract expires. This estimate is based upon 2016 coal with a heating value of 8,890 Btu/lb and a sulfur content of 0.85%. (document prepared by C. Nelson, BHP Navajo Coal Company on 27 February 2006 and submitted by Sithe Global as part of the Desert Rock permit application).

[4] All projections are based upon fuel quality estimates from the coal supplier and WRAP utilization growth projections.

[5] 70 F.R. 39134 (July 6, 2005).

[6] http://www.epa.gov/airmarkets/emissions/prelimarp/05q4/054_nm.txt

[7] 70 F.R. 39131, July 6, 2005.

[8] 70 F.R. 39135, July 6, 2005.

[9] http://www.epa.gov/airmarkt/arp/nox/controltech.html

Figure 1.a. WRAP Total Extinction Trends

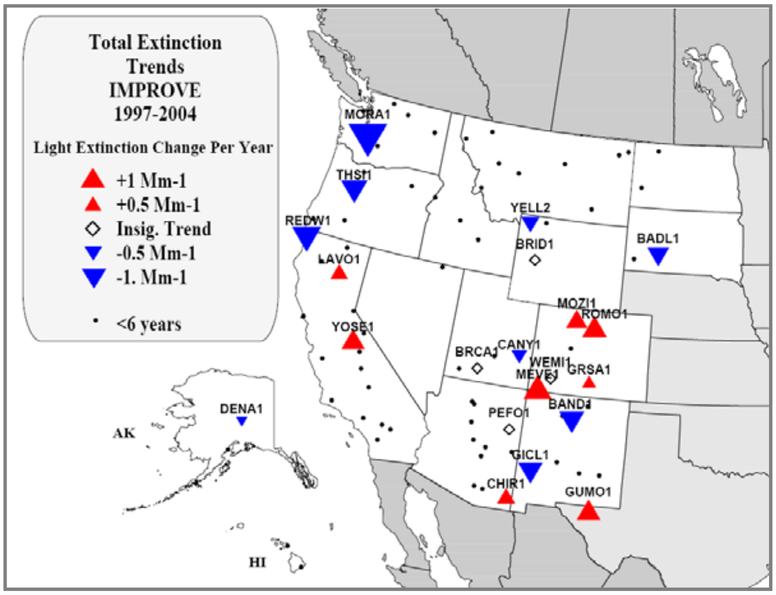


Figure 1.b. WRAP Sulfate Extinction Trends

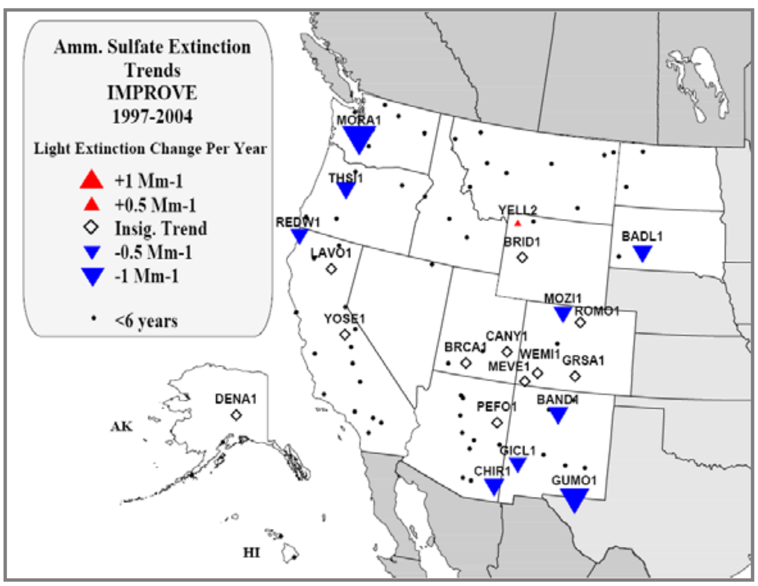


Figure 1.c. WRAP Nitrate Extinction Trends

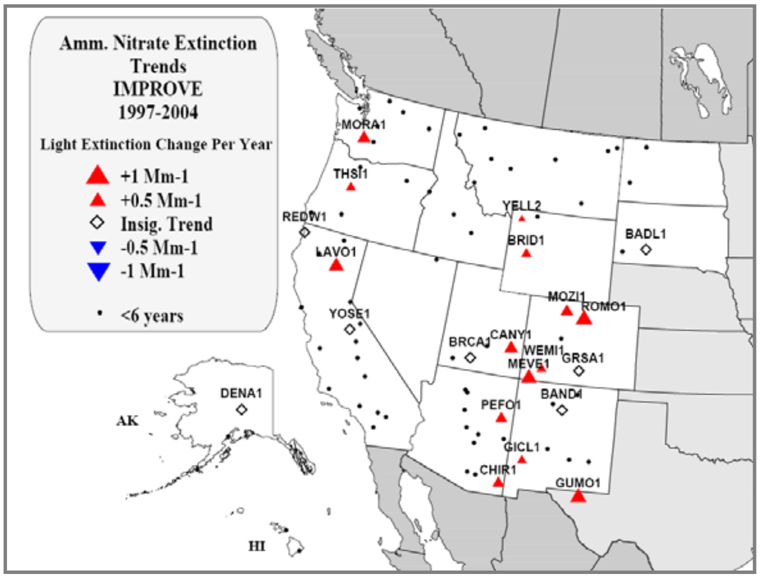


Figure 2. FCPP Emission Trends

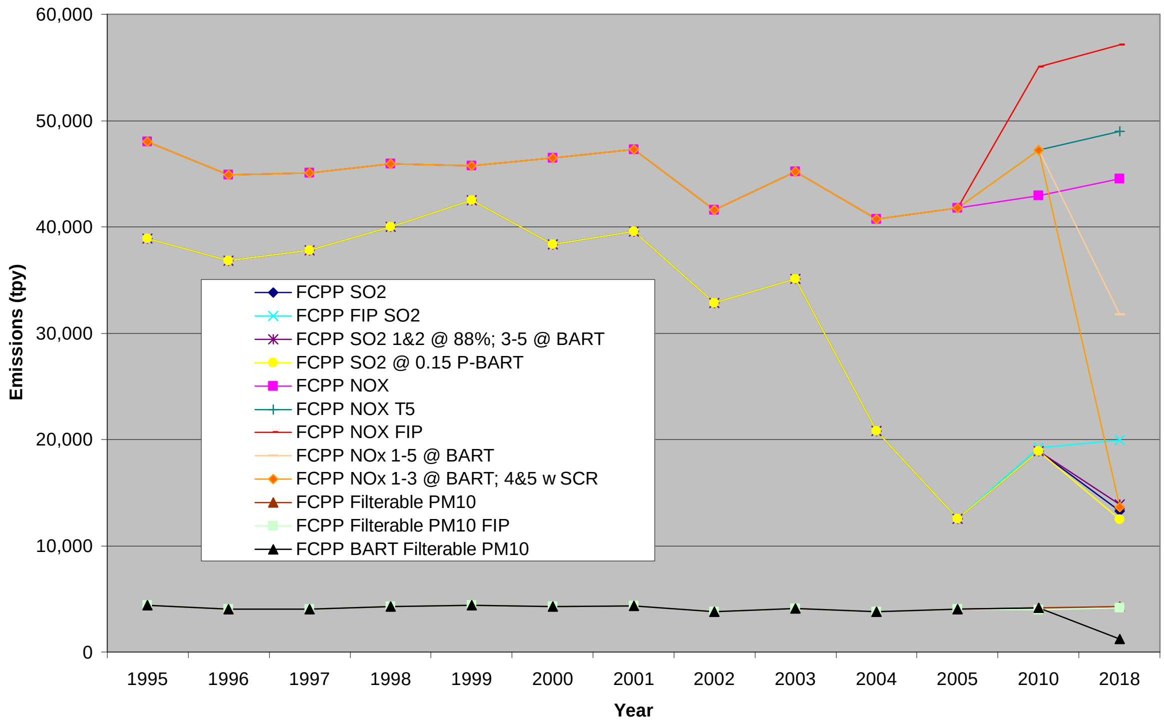


Figure 3. FCPP 2018 SO2 vs. Control Strategy

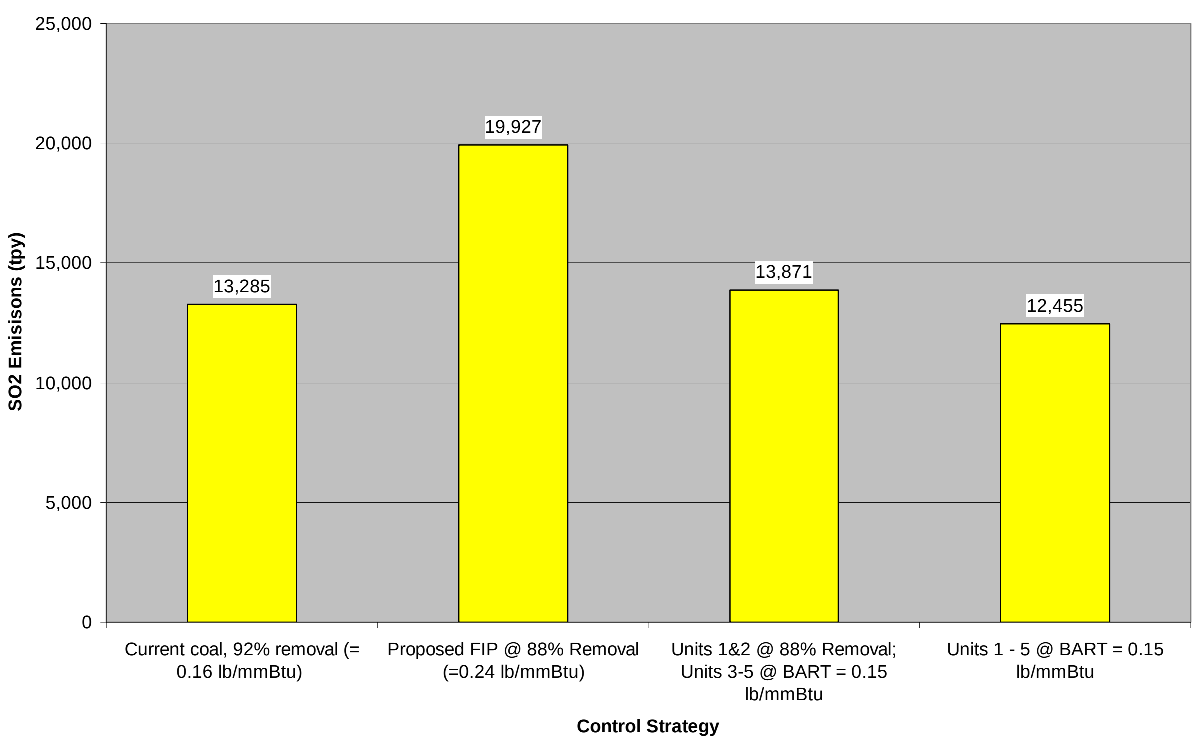
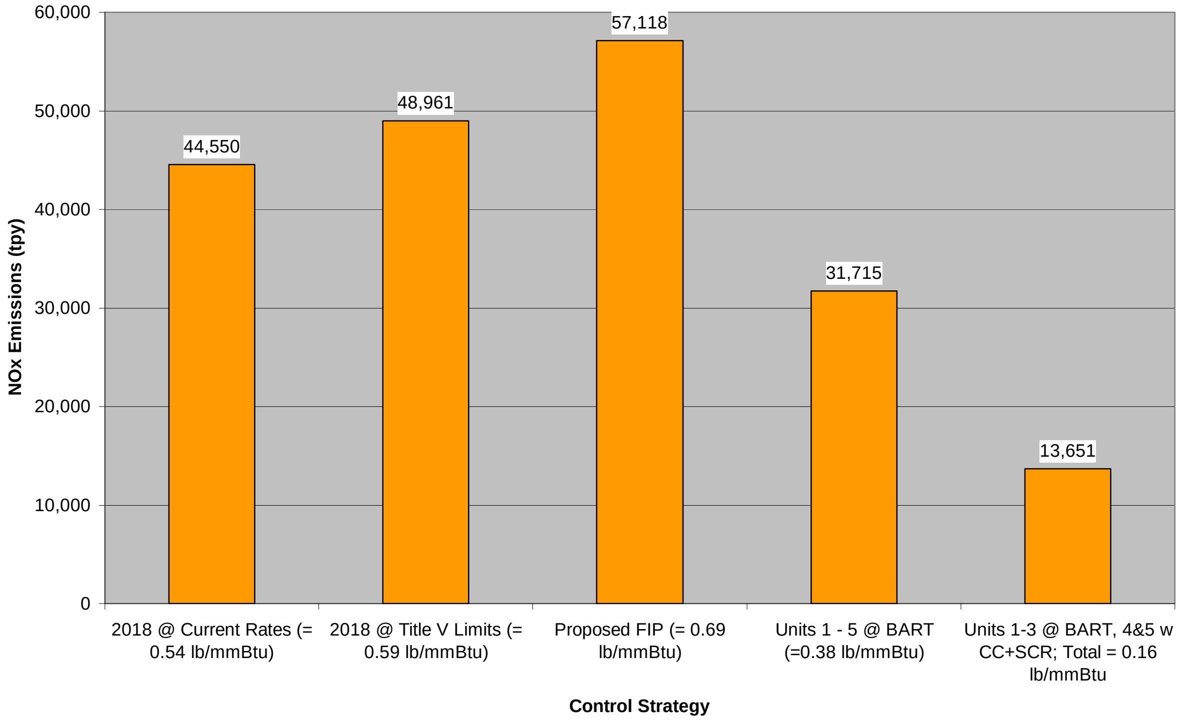


Figure 4. FCPP 2018 NOx Emissions vs Control Strategy



Mitigation Option: Control Technology Options for San Juan Generating Station

<u>I. Description of the mitigation option</u>

Summary of Option

Presumptive emission limits for NO_x should be applied to all units at San Juan Generating Station (SJGS).

Background: Best Available Retrofit Technology (BART)

SGJS consists of four pulverized coal fired boilers. Each boiler was built between 1962 and 1977 and emits more that 250 tons per year of visibility-impairing pollution. The units are therefore subject to the Best Available Retrofit Technology (BART) requirements under the Regional Haze Rule. The BART requirements mandate industrial facilities that cause or contribute to regional haze to control emissions of visibility-impairing pollutants. The Clean Air Act (CAA) states that BART guidelines shall apply to fossil-fueled fired generating power plants with a capacity greater than 750 MW (§169A(b)). The CAA does not exempt individual units of any size from BART requirements.

For Electric Generating Units with a capacity greater than 200 MW, the Environmental Protection Agency (EPA) has provided (rebuttable) presumptive emission limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_x), based on boiler size, coal type and controls already in place. EPA "analysis indicates that these controls are likely to be among the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement." (70 FR 39131, July 6, 2005). Those presumptive limits (which are 30-day rolling averages) are:

- Unit #1 is 359 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #2 is 359 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #3 is 555 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #4 is 555 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu

Background: SJGS Emissions

In March of 2005, Public Service of New Mexico (PSNM) entered into a Consent Decree to reduce SO_2, NO_x, and PM_{10} emissions by 2010 at SGJS to the levels shown below:

- NO_x = 0.30 lb/mmBtu (30-day rolling average). The Consent Decree requires that San Juan minimize NOx emissions. The 0.30 lb/mmBtu limit will be evaluated after 1 year of operation and adjusted to a lower limit if possible.
- SO_2 = 90% annual average control,[1] not to exceed 0.250 lb/mmBtu for a seven-day block average.
- PM_{10} = 0.015 lb/mmBtu (filterable)

PSNM will replace all four existing Electrostatic Precipitators with Fabric Filters. San Juan currently meets the 0.015 lb/mmBtu limit with the existing Electrostatic Precipitators. The fabric filters (baghouses) will be installed primarily to reduce opacity spikes during upset conditions and to allow the addition of activated carbon for mercury control.

PSNM will have to meet the 90% SO_2 control requirement regardless of the coal quality. Current coal quality averages about 1.4 lb SO_2/mmBtu (uncontrolled). Therefore, ninety percent control would result in an annual average emission rate of 0.14 lb/mmBtu, and would likely satisfy the presumptive BART requirement.

Presumptive BART for NO_x at SJGS
The Consent Decree (CD) level for NO_x is 0.30 lb/mmBtu; the BART presumptive level for NOx is 0.23 lb NO_x/mmBtu. The BART presumptive level is lower than that in the CD, and therefore will result in lower emissions. Figure 1 depicts the historical trends of SO_2 and NO_x at SJGS, as well as future trends out to 2018 based upon available information on coal quality[2] and capacity utilization.[3] Emission increases after 2010 are due to increased utilization. The decreased NO_x emissions are based on the assumption that SJGS Units 1-4 will meet the presumptive BART limit for NO_x by 2018.

The presumptive BART level of 0.23 lbs/mmBtu was developed based on Powder River Basin (PRB) Coal. Although both the PRB and the San Juan Basin coals are considered sub bituminous, San Juan coal has properties of bituminous coal which has a higher presumptive BART level.

Reduction of NO_x is particularly important to improve visibility at Mesa Verde National Park, which is 43 km away from SJGS. As shown in Figures 1a, 1b and 1c, visibility has degraded at Mesa Verde over the past decade, and the portion of degradation due to nitrate has increased (while there has been no trend in degradation due to sulfate).

II. Description of how to implement

A. Mandatory or voluntary:
This option represents a mandatory, federally enforceable emission limit.

B. Indicate the most appropriate agency(ies) to implement:
The regulating agency for this facility is the State of New Mexico.

III. Feasibility of the option

The Environmental Protection Agency's suggested presumptive BART limits "reflect highly cost-effective technologies."[4] EPA, in fact, performed visibility impact and cost-effectiveness analyses on the presumptive limits. Therefore, the BART presumptive limits of NO_x are considered to be technical and economically feasible.

EPA states that the majority of units could meet these NO_x limits with current combustion control technology for between \$100 and \$1000 per ton of NO_x removed. If more advanced combustion controls are required, the cost would be less than \$1500 per ton of NO_x removed. Furthermore, EPA states that "by the time units are required to comply with any BART requirements . . . more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NO_x limits are conservative.[5]

The most accurate cost estimate for SJGS to meet the BART limit for NO_x is likely to be from EPA's Cost Tool model, which estimates costs for specific units at specific emission rates.[6] That model predicts that the presumptive BART limits for NO_x could be met at costs of \$355 - \$501 per ton.

San Juan is currently in the process of doing a BART Analysis. It will be submitted to the NMED in June 2007.

IV. Background data and assumptions used

Historical emissions data comes from EPA's Clean Air Markets Division databases. Projected capacity utilizations come from the Western Regional Air Partnership's "11 State EGU Analysis" projections.
EPA's Cost Tool Model: http://www.epa.gov/airmarkt/arp/nox/controltech.html

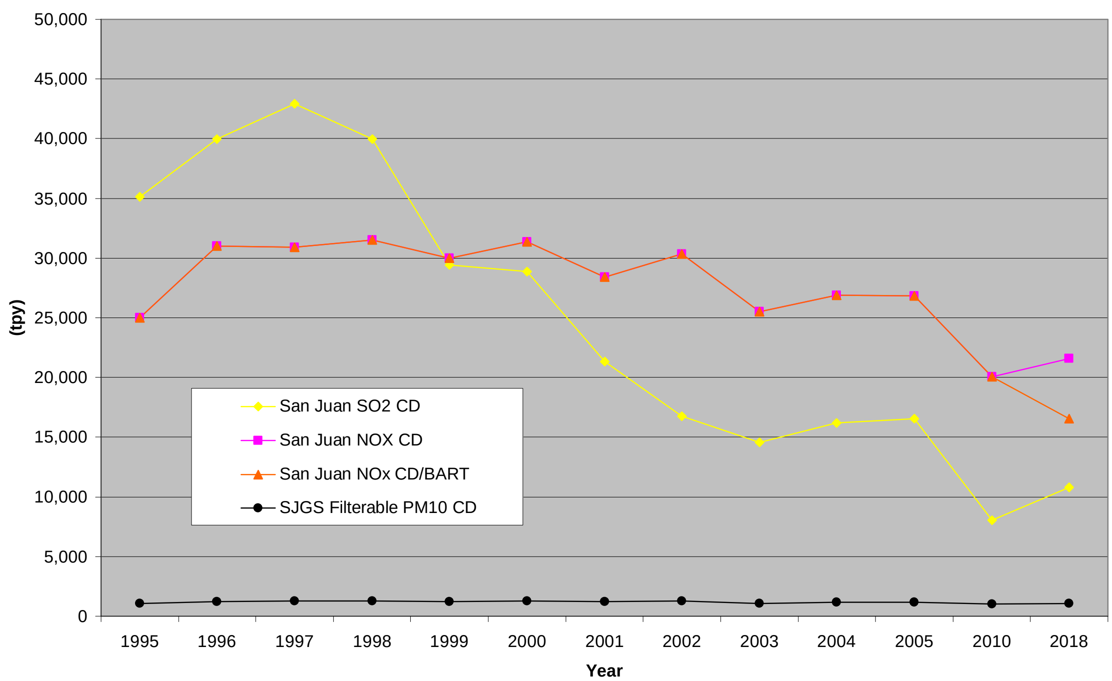
V. Any uncertainty associated with the option (Low, Medium, High)
Uncertainties in SJGS's ability to meet the BART presumptive limit for SO2 include future coal quality. Future emissions of SO_2, NO_x and PM10 will depend on future utilization, which at this point has been predicted.

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None.

Citations:
[1] Based upon scrubber inlet and outlet SO_2 concentrations, as measured by Continuous Emission Monitors.
[2] Document prepared by C. Nelson, BHP Navajo Coal Company on Feb. 27, 2006 and submitted by Sithe Global as part of the Desert Rock permit application.
[3] Western Regional Air Partnership, 11 State EGU Analysis spreadsheet
[4] 70 F.R. 39131, July 6, 2005.
[5] 70 F.R. 39135, July 6, 2005.
[6] http://www.epa.gov/airmarkt/arp/nox/controltech.html

Figure 1. San Juan SO2 & NOx



EXISTING: OPTIMIZATION

Mitigation Option: Energy Efficiency Improvements

I. Description of the mitigation option

Upgrades or major repairs to existing power plants are potentially subject to the New Source Review process. This includes projects that are undertaken to improve the efficiency of the plants (i.e., produce more power while burning less or the same amount of fuel.) This process has been so difficult and cumbersome that these projects are often not cost-effective to pursue. The regulatory agencies should work closely with the utilities to simplify the process, remove barriers and to encourage these efficiency improvements.

II. Description of how to implement

A. Mandatory or voluntary:

B. Indicate the most appropriate agency(ies) to implement

Regulating agencies:

EPA Region 9 Air Programs, Navajo Nation EPA, New Mexico Air Quality Bureau

III. Feasibility of the option

A. Technical:

B. Environmental:

C. Economic:

IV. Background data and assumptions used:

V. Any uncertainty associated with the option (Low, Medium, High):

Medium

VI. Level of agreement within the work group for this mitigation option.

TBD

VII. Cross-over issues to the other Task Force work groups:

None

Mitigation Option: Enhanced SO_2 Scrubbing

I. Description of the mitigation option

Enhanced SO_2 scrubbing on existing power plants in the Four Corners area has resulted in significant SO_2 reductions. This mitigation option suggests further efforts to develop and optimize SO_2 scrubbing at San Juan Generating Station and Four Corners Power Plant.

Background:
Wet Flue-Gas Desulfurization System:
Wet scrubbing, or wet flue gas desulfurization (FGD), is the most frequently used technology for post-combustion control of SO_2 emissions. It is commonly based on low-cost lime-limestone in the form of aqueous slurry. Lime is calcium oxide, CaO; Limestone is $CaCO_3$. The slurry brought into contact with the flue-gas absorbs the SO_2 in it. $CaSO_4$-$2H_2O$, Gypsum, is formed as a byproduct (1).

Gas flow per unit cross sectional area, which determines scrubber diameter, must be low enough to minimize entrainment. Mass transfer characteristics of the system determine absorber height. These vessels and the accompanying equipment used for slurry recycle, gypsum dewatering, and product conveyance tend to be quite large. Some variations of this technology produce high quality gypsum for sale. Less pure waste product may be sold for use in cement production. If neither of these options is practiced, the scrubber waste must be disposed of in a sludge pond or similar facility (2).

The wet scrubber has the advantage of high SO_2 removal efficiencies, good reliability, and low flue gas energy requirements (1).

What is being done:
San Juan Generating Station has initiated an Environmental Improvement program under its consent decree that includes enhanced SO_2 scrubbing. Projections show that optimization of SO_2 scrubbing will result in a reduction of SO_2 from the current emission rate of 16,569.5 tons/yr to an emissions rate of 8,900 tons/yr by the year 2010 (3, 4, 5). This would translate as an increase in SO_2 removal efficiency from 81% to 90% as required by the consent decree.

The Consent Decree that San Juan has entered into will require a minimum of 90% removal of SO2.

Four Corners Power Plant has also made significant improvements in SO_2 emissions control efficiency. APS, in partnership with the Navajo Nation, several environmental groups and federal agencies, conducted a test program to determine if the efficiency of the existing scrubbers at Four Corners Power Plant could be improved from the recent historical level of 72% SO_2 removal to 85%. The test program, which was completed in spring of 2005, was successful and the plant was able to achieve a plant-wide annual SO_2 removal of 88%. In fact, data indicates that a 92% removal, or 0.16 lbs/mmBtu SO2 limit was achieved. Some parties involved in the test program have agreed that a new rule should propose to require 88% removal efficiency for the Four Corners Power Plant (6). Parties are also interested, however, in a mass emissions limit as opposed to removal rate to protect against air quality degradation from higher sulfur coal.

The way "removal" is used here is based on including the amount of sulfur retained in the ash. For FCPP, this amounts to about 2% "bump-up" of the control efficiency. So, 88% removal is the equivalent of 86% control. By contrast, both the NM regulations and the SJGS consent decree require that the control efficiency across the scrubber be measured by CEMs before and after the scrubber.

72% SO_2 removal resulted in approximately 22,450 Tons/yr SO_2 emissions. The new emissions control removal efficiency of 88% translated to 12,500 Tons/yr SO2 emissions in 2005.

Further advances in SO_2 scrubber optimization should be explored and implemented as they become available. It may be possible to achieve over 90% SO_2 removal efficiencies with enhanced SO_2 scrubbing on existing power plants in the 4C area

During 2005, FCPP demonstrated that it can achieve better than 90% control of SO_2.

Benefits: SO_2 removal increase. Possible co-benefits are increased particulate removal, and also mercury removal.
Tradeoffs:
Burdens: Cost to existing power plants including: optimization controls or additional retrofit technologies.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary emissions reductions that are above and beyond new standards

Differing Opinion: A FCPP FIP that reflects the capabilities of the control equipment and coal supply

B. Indicate the most appropriate agency(ies) to implement
New Mexico Air Quality Bureau
EPA Region 9 and Navajo Nation EPA

III. Feasibility of the option
A. Technical: technology is available and feasible.
B. Environmental: Optimized SO2 scrubbing could result in SO_2 control efficiency above 90%.
C. Economic: Improving existing emissions control process through optimization is often less expensive than retrofitting plant with entirely new emissions control equipment.

IV. Background data and assumptions used:
1. El-Wakil, M.M. Power Plant Technology; McGraw-Hill, New York: 2002.
2. Clean Coal Technology Topical Report #13, May 1999, DOE, "Technologies for the combined Control of Sulfur Dioxides and Nitrogen Oxides from Coal-fired Boilers"
3. Current estimated SO_2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
4. San Juan Generating Station (SJGS) presentation for 4CAQTF, August 9, 2006, "SJGS Emissions Control Current and Future"
5. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
6. Final rule for Four Corners Power Plant:
ENVIRONMENTAL PROTECTION AGENCY, 40 CFR Part 49, [EPA-R09-OAR-2006-0184; FRL-], Source-Specific Federal Implementation Plan for Four Corners Power Plant; Navajo Nation

V. Any uncertainty associated with the option
Medium – SO_2 scrubbing control efficiencies have increased recently. Optimization of SO_2 scrubbing systems have limitations.

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None

EXISTING: ADVANCED NO_x CONTROL TECHNOLOGIES

Mitigation Option: Selective Catalytic Reduction (SCR) NO_x Control Retrofit

I. Description of the mitigation option,
To reduce NOx emissions from the existing power plants in the Four Corners area, a Selective Catalytic Reduction system could be retrofitted to San Juan Generating Station and Four Corners Power Plant.

Selective Catalytic Reduction, SCR, uses ammonia or urea along with catalysts in a post-combustion vessel to transform NO_x into nitrogen and water. It can achieve the 0.15-pound-per-million Btu standard (1).

Some eastern EGUs retrofitted with SCR have achieved 0.05 lb/mmBtu. Based on recent permit applications and boilers in the east that have retrofitted with SCR, this technology can typically achieve a 90 percent reduction in NO_x emissions.

Ammonia is used as the reducing agent. It is injected into the flue gas stream and then passes over a catalyst. The ammonia reacts with nitrogen oxides and oxygen to form nitrogen and water.

The main Selective Catalytic Reduction reaction is $4NH_3 + 4NO + O_2 \rightarrow 4\ N_2 + 6H_20$ (2)

Supplemental description of Selective Catalytic Reduction available from US EPA, AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01) (for Desert Rock Energy Facility)

This report further discusses technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system (3).

And the SCR system
The SCR system is comprised of a number of subsystems. These include the SCR reactor and flues, ammonia injection system and ammonia storage and delivery system (3).

Based on heat input and emissions data from the Acid Rain Program:
Currently NO_x emissions from San Juan Generating Station are on the order of 0.42 lbs/mmBtu or 26,800 Tons/yr.
Currently NOx emissions from the Four Corners Power Plant are approximately 0.57 lbs/mmBtu or 40,700 Tons/yr (4). Note: FCPP is the largest NOx-emitting EGU is the US.

The proposed Desert Rock Energy facility is planning to build their facility with Selective Catalytic Reduction technology to control NO_x emissions. They expect 85-90% control of NOx. The permit allowed NOx emissions will be 0.060 lbs/mmBtu fuel input (2).

Retrofitting a Selective Catalytic Reduction to existing power plants would be much more difficult than installing equipment with the construction of the plant; however, it is an option to greatly reduce NOx emissions from existing sources. It may be able to reduce emissions from existing sources by as much as 50%.

Differing Opinion: Applying SCR to existing plants may be more difficult than new installation; it is not a given. SCR has been successfully applied in the East in response to the CAIR rule. Retrofits at eastern utilities subject to the NOx SIP Call and CAIR typically set a 90% reduction goal. The vintage EPA Cost Tool database assumes 70% control by SCR, and SCR has improved dramatically since then.

Benefits: It is an option to greatly reduce NOx emissions from existing sources. It may be able to reduce emissions from existing sources by as much as 50% - 90%+. SCR may have some co-benefit reductions of Mercury emissions.

Tradeoffs:
Ammonia that is not reacted will "slip" through into exhaust. Ammonium salts could also form thus increasing loading to the particulate collection stage as PM10 (and PM2.5) (2). This is less likely with lower sulfur coal.
SCR tends to increase the reaction of SO_2 to SO_3 and increases the formation of acid mists. This could require additional treatment of the flue gas. This is less likely with lower sulfur coal.

Any analysis should compare the cost of SCR to the costs of combustion controls.

Application of EPA's Cost Tool model for the Four Corners Power Plant, Units 4 & 5 predicts that NO_x could be reduced by 70 percent to the levels shown by application of combustion controls plus SCR at a cost of \$409 - \$464 per ton of NO_x removed. EPA states that the average cost of combustion controls on cell burners (presumptive BART) is \$1021 per ton. The average cost of applying SCR to cyclone units, (which for those units is presumptive BART), is \$900 per ton.

Burdens: Retrofit costs to existing power plants. Installation may be cost prohibitive for some existing plants because of the physical layout of the plant. Safety issue with handling of ammonia for use as reducing agent

II. Description of how to implement
A. Mandatory or voluntary
Retrofit program could be mandatory or voluntary
SCR application could be considered in the context of BART.

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Bureaus, Federal EPA, Industry

III. Feasibility of the option
A. Technical – commercially available

B. Environmental – high reduction efficiencies demonstrated 85-90+%.
Sulfur content of the coal is an important factor in use of SCR. The low-sulfur coals burned in the 4 Corners area should be more compatible with SCR. SCR is being widely applied to a variety of bituminous and sub-bitumninous coals, especially in the East. Requiring catalyst replacement is an economic issue.

The SCR process is subject to catalyst deactivation over time (2).

C. Economic – Retrofit costs. Additional maintenance costs

*Cumulative Effects Work Group – How would 50%-90% emissions reductions from the two existing power plants affect visibility and ozone?
*Monitoring Work Group – Would it be possible to measure ammonia slip in the exhaust gases?

IV. Background data and assumptions used

1. US Department of Energy (DOE) Pollution Control Innovations Program
http://www.fossil.energy.gov/programs/powersystems/pollutioncontrols/index.html

2. Development of Nitric Oxide Catalysts for the Fast SCR Reaction, Matt Crocker, Center for Applied Energy Research, University of Kentucky (2005)

3. US EPA, AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01) (for Desert Rock Energy Facility)
*A good description of Selective Catalytic Reduction is available on pp.9-10 of the US EPA, Ambient Air Quality Impact Report, Best Available Control Technology discussion, for the Desert Rock Energy Facility.

4. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
Heat input for all 4 units at San Juan Generation Station 127,629,979 mmBtu in 2005.
Heat input for all 5 units combined at 4Corners Power Plant 141,394,388 mmBtu in 2005.

5. San Juan Generating Station (SJGS) presentation for 4CAQTF, August 9, 2006, "SJGS Emissions Control Current and Future"

V. Any uncertainty associated with the option High.

Differing Opinion: The success of SCR in reducing NO_x emissions is a proven technology

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Oil & Gas industry may also look at SCR as a method to reduce natural gas compressor NO_x emissions

Mitigation Option: BOC LoTOx^{TM} System for the Control of NOx Emissions

I. Description of Mitigation Option

Belco BOC LoTox is an oxidation technology for flue gas NOx control. It was developed in recent years and has become commercially successful and economically viable as an alternative to ammonia and urea based technologies. Older commercial technologies such as Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR), which reduce NOx to nitrogen using ammonia or urea as an active chemical, are limited in their use for high particulate and sulfur containing NOx streams such as from coal-fired combustors, or are unable to achieve sufficient NOx removal to meet new NOx regulation levels. In contrast, oxidation technologies convert lower nitrogen oxides such as nitric oxide (NO) and nitrogen dioxide (NO2) to higher nitrogen oxides such as nitrogen sesquioxide (N2O3) and nitrogen pentoxide (N2O5). These higher nitrogen oxides are highly water soluble and are efficiently scrubbed out with water as nitric and nitrous acids or with caustic solution as nitrite or nitrate salts. NOx removal in excess of 90% has been achieved using oxidation technology on NOx sources with high sulfur content, acid gases, high particulates and processes with highly variable load conditions.

The BOC LoTOx^{TM} System is based on the patented Low Temperature Oxidation (LTO) Process for Removal of NOx Emissions, exclusively licensed to BOC Gases by Cannon Technology. This technology has met the stringent cost and performance guidelines established by the South Coast Air Quality Management District in Diamond Bar, CA and has set new lower limits for Best Available Control Technology (BACT) and Lowest Achievable Emissions Reduction (LAER). The LoTOx^{TM} System for NOx Control uses oxygen to produce ozone as the primary treatment chemical using an ozone generator. The oxidation of NOx using ozone is a naturally occurring process in the atmosphere. The absorption of higher nitrogen oxide by water to form nitric acid is also a naturally occurring process in the atmosphere, resulting in “acid rain”. The LoTOx^{TM} System reproduces these naturally occurring processes under controlled conditions within an enclosed system. This treatment method produces the treatment chemical, ozone, on demand from gaseous oxygen in the exact amount required for oxidation of the NOx.

A demonstration was conducted at Southern Research Institute’s (SRI) Combustion Research Facility, Birmingham, AL using a mobile demonstration trailer. The test was the first in a series of tests planned to demonstrate the effectiveness of ozone for oxidation and removal of NOx emissions from SRI’s coal-fired combustor. The results from the tests demonstrated that the LoTOx^{TM} System is highly effective for removal of NOx emissions from as high as 350 ppmv NOx to below 50 ppmv NOx levels without significant residual ozone in the exhaust stream. The LoTOx^{TM} System is very selective for NOx removal, oxidizing only the NOx and therefore efficiently using the treatment chemical, ozone, without causing any significant SOx oxidation and without affecting the performance of the downstream SOx scrubber. Furthermore the ozone/NOx ratios required to produce desired NOx oxidation are less than the predicted stoichiometric amounts. Various types of coals and fuel types will be used in the combustor. The information gathered will be used for the design of commercial LoTOx^{TM} Systems for effective and efficient NOx removal at utility power plants and other large-scale NOx sources. [1]

Chemistry

The LoTOx process is based on the excellent solubility of higher order nitrogen oxides. Typical combustion processes produce NOx streams that are approximately 95% NO and 5% NO2. Both NO and NO2 are relatively insoluble in aqueous streams, therefore, wet scrubbers will only remove a few percent of NOx from the flue gas stream. Species Solubility at 25°C and 1 atm

NO 0.063 g/l, NO2 1.260 g/l

The LoTOx process uses ozone to oxidize NO and NO2 to N2O5 ,which is highly soluble, and by wet scrubbing N2O5 is easily and quickly converted to HNO3, based on the following reactions:

NO + O3 -> NO2 + O2

2NO2 + O3 -> N2O5 + O2

$N_2O_5 + H_2O \rightarrow 2HNO_3$
Both N_2O_5 and HNO_3 are extremely soluble in water. N_2O_5 reacts instantaneously with water forming HNO_3. Since HNO_3 is so highly soluble (approaching infinity) it is difficult to measure, and therefore reliable solubility data is not available in published literature. However, HNO_3 mixes with water in all proportions and therefore the N_2O_5 to HNO_3 reaction is irreversible in the presence of water. [2]

Benefits: Low Temperature, No chemical slip
Tradeoffs:

Burdens:
Ozone unused in the treatment process produces no health hazards to plant workers nor to the environment. The ozone is injected into flue gas stream where it reacts with relatively insoluble NO and NO_2 to form N_2O_3 and N_2O_5, which are highly water soluble, and are easily and efficiently removed and neutralized in a wet scrubbing system. [1]

II. Description of how to implement
A. Mandatory or voluntary
LoTOx could be the answer to achieve required limits under regional haze rule. This control technology could be an option to meet mandatory emissions limits

B. Indicate the most appropriate agency(ies) to implement
4 Corners Power Plants would implement new technology as an integrated component of emissions control system

III. Feasibility of the option
A. Technical: Low temperature reaction is good. Ozone generation and other LoTOx system components are well understood technologies used in other applications.
B. Environmental: Pilot scale demonstrations showed 90% removal, very high reduction efficiencies
C. Economic: Retrofit technologies can be expensive on existing power plants.

This technology has only been tested on pilot plants and there are no full scale installations. The technology should therefore, at this point, be considered not technically feasible.

IV. Background data and assumptions used
1. DEMONSTRATION AND FEASIBILITY OF BOC LoTOx™ SYSTEM FOR NOx CONTROL ON FLUE GAS FROM COAL-FIRED COMBUSTOR abstract, presented at 2000 Conference on SCR & SNCR for NOx Control/BOC,
http://www.netl.doe.gov/publications/proceedings/00/scr00/ANDERSON.PDF
2. CARB Innovative Clean Air Technology, "Low Temperature Oxidation System Demonstration," BOC paper 1999, http://arbis.arb.ca.gov/research/apr/past/icat99-2.pdf
3. DuPont BELCO LoTOx Technology homepage
http://www.belcotech.com/products/nox.html

V. Any uncertainty associated with the option
Medium, any retrofit technology has a degree of uncertainty. It can be difficult and expensive to retrofit emissions control technology that the plant was not originally designed for.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

EXISTING: OTHER RETROFIT TECHNOLOGIES

Mitigation Option: Baghouse Particulate Control Retrofit

I. Description of the mitigation option

Installation of baghouses at existing power plants in the Four Corners area could reduce particulate emissions by approximately 25% or more. Baghouses, or fabric filters, as they are often called, collect fly ash and other particulate matter from the coal combustion process like large vacuum cleaners. Typically a baghouse removes more than 99.8 % of the fly ash.

The original design for the two major power plants in the 4 Corners area was for electrostatic precipitators (ESPs). The ESPs on San Juan Generating Station remove approximately 99.7 % of the particulate matter from the exhaust stream. This exceeds current state and federal emissions requirements (0.1 lbs/mmBtu and 0.05 lbs/mmBtu).

The San Juan generating station is currently undergoing a series of environmental improvements between 2007 and 2009 including designing for a 0.015 lbs/mmBtu particulate limit. PNM will install fabric filters (baghouses) for all four SJGS units collect particulate emissions. The ESPs at San Juan will remain in place but will be de-energized. It is believed that a portion of the ash will continue to be removed in the ESPs (because of gravity separation) but they will not be considered a control device. One of the reasons to install the baghouses was because of PNM's commitment for Activated Carbon Injection for the removal of mercury. An ESP would not have been efficient in the collection of the activated carbon. An additional benefit of the baghouse is the reduction of opacity spikes that are caused by an increase in unburned carbon in the flyash. This unburned carbon is caused by combustion problems associated with the operation of the low-NOx burners and is not efficiently collected by an ESP. Also, we will not know until the Baghouses are installed and operational, but we do not anticipate that the actual particulate emissions will be significantly less than the current emissions. However, the permit requirement will be reduced from 0.05 lbs/mmBtu to 0.015 lbs/mmBtu.

Since all units at San Juan and Units 4 & 5 at Four Corners currently have or will have baghouses in the near future, this option will only apply to Units 1,2 & 3 at Four Corners.

Benefits: Current reported levels of particulate emissions at major power plants in the 4Corners area include: San Juan Generating Station emits approximately 673 Tons/yr, approximately .011 lbs/mmBtu; 4 Corners Power Plant emits approximately 1,187 Tons/yr, approximately .017 lbs/mmBtu (see 4CAQTF_PowerPlant_WorkGroup_ FacilityDataTableV10). Baghouse installation may result in improved particulate removal efficiencies. If baghouses could reduce emissions to .010 lbs/mmBtu, this option could lead to over 500 tons per year reduction of particulates collectively from the two largest coal fired power plants in the region.

Differing Opinion: The benefits (500 ton reduction of particulates) may be over estimated because San Juan and Four Corners Unit 4 & 5 will have baghouses and will perform at or close to the 0.01 lbs/mmBtu. The only units that would see a reduction would be Four Corners Units 1,2 & 3.

Burdens: Cost of baghouse installation on power plants

II. Description of how to implement

A. Mandatory or voluntary
Voluntary or consent decree

B. Indicate the most appropriate agency(ies) to implement
Power Plants would install

III. Feasibility of the option
A. Technical: Technology is available commercially

B. Environmental: Feasible

C. Economic: Expensive to install new technology

IV. Background data and assumptions used
1. San Juan Generating Station (SJGS) Emissions Control Current and Future, presentation for 4CAQTF, May 2006 ,http://www.nmenv.state.nm.us/aqb/4C/Docs/SanJuanGeneratingStation.pdf

2. 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10

3. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
Heat input for all 4 units at San Juan Generation Station 127,629,979 mmBtu in 2005.
Heat input for all 5 units combined at 4Corners Power Plant 141,394,388 mmBtu in 2005.

4. San Juan Environmental Improvement Upgrades Fact Sheet, http://www.pnm.com/news/docs/2005/0310_sj_facts.htm

V. Any uncertainty associated with the option
Medium.

VI. Level of agreement within the work group for this mitigation option
TBD.

VII. Cross-over issues to the other Task Force work groups
None.

Mitigation Option: Mercury Control Retrofit

I. Description of the mitigation option
Existing power plants in the Four Corners area should evaluate the installation of mercury removal technology to reduce mercury emissions. According to EPA's 2005 Toxic Release Inventory report the San Juan Generating Station released 770 lbs and Four corners Power Plant released 625 lbs of mercury into the air. Activated carbon injection technology is the most likely control technology at this time. This technology has been demonstrated in several pilot studies.

The Clean Air Mercury Rule (CAMR) will require the reduction of mercury emissions from power plant beginning in 2010 with further reductions in 2018. This rule will also require the installation of mercury Continuous Emissions Monitoring systems by January 1, 2009.

San Juan Generating Station will have mercury control (activated carbon injection) on all four units by 2010 and Mercury CEMs on 2 units by 2008 and all 4 units by 2009.

II. Description of how to implement
A. Mandatory or voluntary: Mandatory and/or Voluntary

B. Indicate the most appropriate agency(ies) to implement
Regulating agencies:
EPA Region 9 Air Programs, Navajo Nation EPA, New Mexico Environment Department

III. Feasibility of the option
A. Technical: The injection of activated carbon into the flue gas stream has been demonstrated in pilot studies to remove mercury. However, there have not been any long-term applications of this technology. Also the effectiveness of this technology has not been demonstrated on the type of coal in the San Juan Basin so the actual removal efficiency of the technology is unknown. Nevertheless, many new coal-fired power plant projects are proposing installation of activated carbon injection.

B. Environmental: Mercury emissions will be reduced, however, the addition of activated carbon to the fly ash will make the ash unsuitable for sale to the cement/concrete industry and will increase the amount of fly ash that will have to be disposed.

C. Economic: The cost of additional equipment for ACI injection is relatively small, however, the annual operating and maintenance cost can be significant because of the cost of the activated carbon. Also there currently is a limited supply of activated carbon. The increase cost for ash disposal could be significant. Also, ACI injection requires a bag house or fabric filter for particulate control. This cost would be significant if this technology would have to be retrofitted to existing units.

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

EXISTING: STANDARDS

Mitigation Option: Harmonization of Standards

I. Description of the mitigation option,
This option would require existing power plants to meet the most stringent standard of any governmental agency in the region, i.e., the strictest state, federal, or tribal standard. At present facilities are subject to varying standards depending on where they are located, even though emissions affect the entire area and beyond.

This option is limited to existing power plants on the basis that new power plants are held to Best Available Current Technology (BACT) limitations on controlled emissions, which are usually much lower than current state or federal air standards.

One of problems in the Four Corners area is the aging fleet of large power plants. These older power plants have significantly higher emissions than potential new sources. The two largest generating stations in the Four Corners Region, Four Corners Power Plant (FCPP) and the San Juan Generating Station (SJGS), are regulated by different agencies even though they are within 30 miles of each other. San Juan Generating Station is being held to more stringent regulations by the New Mexico Air Quality Bureau regulations.

The burden of this requirement to adopt more stringent regulations would fall on the owners of the facilities and might also lead to the eventual retirement of some older Four Corner area power plants. However, the long-term effect of this rule, especially if applied to other multi-state regions over time, might lead to standardized regulations, also a benefit, if the new standards converged on the most stringent requirement.

II. Description of how to implement
This rule should be mandatory and phased in over a designated period of time.

A valuable lesson is to be learned from the Four Corners Power Plant jurisdiction quandary. The Navajo Tribe ruled that the State of NM cannot regulate and enforce FCPP emissions. Very recently, a lawsuit was filed against the Federal EPA regarding FCPP emissions. This lawsuit may have expedited the current series of action by the Federal EPA such as public sessions, the FIP, etc. The FCPP is on tribal land, but the air emissions affect the entire Four Corners area. Somehow, a regulatory agency responsible for governing and enforcing emissions of present and future power plants and oil and gas facilities should be agreed upon by all entities.

The area's ozone problem is an example of why it is important to have one regulatory agency. The Four Corners area has unusually high volumes of ground level ozone. The Four Corners Ozone Task Force (FCOTF) has been working for the past several years on ozone mitigation options. The FCOTF is working closely with EPA Region 6. Recently EPA Region 9 officials came to the area to talk about the proposed Desert Rock coal fired power plant. This area's ozone problems were not addressed by EPA Region 9 in the Desert Rock Proposed PSD Permit. In order to avoid costly environmental oversights and/or confusion, only one EPA Region should be designated as the Federal Agency to regulate and enforce in an area such as the Four Corners.

Differing Opinion: Implementing this option could initially be voluntary, as it would ultimately require changes to the Clean Air Act and/or Code of Federal Regulations to address tribal authority over air programs, and the role of the Federal Implementation Plan.

III. Feasibility of the Option
Technical issues: none, technology currently exists to meet the most stringent existing requirement

Environmental issues: Benefits of stricter standards are intuitive. The following are examples of significant disparities in state and federal limits:

For example, the current State permit limit for NOx emissions from San Juan Generating Station is 0.46 lbs/mmBtu. The federal limits for NOx at Four Corners Power Plant are 0.65 – 0.85 lbs/mmBtu. San Juan Generating Station NOx emissions rate is approx. 0.4 lbs/mmBtu or 26,800 Tons/yr. Four Corners Power Plant, under the federal regulation, emits approx 0.6 lbs/mmBtu or approx 41,700 tons/yr

The state limit for SO_2 emissions from San Juan Generating Station is 0.65 lbs/mmBtu. The federal limit applied to Four Corners Power Plant is 1.2 lbs/mmBtu. The state permit limit for PM emissions from San Juan Generating Station is 0.05 lbs/mmBtu. The Federal PM standard is 0.1 lbs/mmBtu.

Economic: Implementation of resulting standards could be expensive. Experience of the political unit currently having the strictest standard could provide some data on the cost. In any case, the standard, even though not industry-wide, would be applicable area-wide and therefore more fair to competing power generators

Political issues: resistance would be great, just as it is now to tightening of standards. Effective implementation of this idea might require creation of a Four Corners regional authority or special district, which might require enabling legislation: the difficulty of accomplishing this is unknown.

IV. Background data and assumptions
The Federal/State PSD rules are applied industry wide for new power plants and existing power plants with major modifications in NAAQS attainment areas. Existing power plants in different jurisdictions continue to be regulated by different standards even though they are in the same air basin. This option would be a step in harmonizing standards. It is clear that the two plants we have heard from could meet tighter standards, especially when applied industry-wide; but since they are not required to do so, they cannot get their owners to support meeting them. It is intuitive that if any installation in the Four Corners region using San Juan Basin coal can meet the tightest standard, they all can over a reasonable period of time.

Green House Gases Such as Carbon Dioxide –
It is becoming more and more apparent that Global Warming or Climate Changes is a world wide problem. Reductions in carbon dioxide emissions, one of the green house gases, should be addressed in the Mitigation Options for all existing and future coal fired power plants in the San Juan Basin. The carbon dioxide issue will have to be dealt with sooner or later and the sooner, the better.

New Mexico Environmental Regulations for Air Quality may be found at:
http://www.nmenv.state.nm.us/aqb/regs/index.html

V. Any uncertainty associated with the option
There is a high level of uncertainty in getting something like this passed politically and how long it would take is an unknown.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues Oil and Gas Work Group, Other Sources Work Group.

EXISTING: MISCELLANEOUS

Mitigation Option: Emission Fund

I. Description of the mitigation option

This option would establish an emissions fund for emitters of one or more air pollutants of concern, such as nitrogen oxides. Sources emitting more than a specified amount annually would pay by the ton emitted into a fund that would then be used for environmental improvement projects. There should be no maximum number of tons over which fees wouldn't be paid.

The fund should be used for environmentally beneficial projects, to be decided by the administering body (see below). One option is to have a grant system whereby applications are made to the fund by anyone—regulated community, environmental community, public, academia, etc—and the administering body would have set criteria against which they evaluated each request. Another option is to specify the allowable uses of the fund, such as for the development or investment in innovative technologies.

Benefits: Ideally, emitters required to pay per ton emitted would have an incentive to emit less. To make this incentive effective, the fee per ton would need to be relatively high. A thorough search of similar programs and any evaluations of those programs should be done to determine what fee level would provide an effective incentive. Monetary incentives could result in emission reductions at significantly lower costs than "command and control" regulation. Emission fees also work to "internalize the externalities" involved in air emissions and environmental degradation by recognizing and attempting to account for the social costs of the operations of the emitters.

Burdens: the primary burden would be on the emitter, to pay into the fund based on annual emissions. There would be some administrative burden, lessened by using existing reporting and oversight frameworks to implement the program.

II. Description of how to implement

A. Mandatory of voluntary: Payment into an emission fund would be mandatory for a defined size or class of sources

B. Most appropriate agency to implement: These programs have generally been administered by state agencies. Tribal air quality agencies could also develop and implement an emissions fund. An oversight committee or the air quality entity with regulatory authority would have authority to administer the fund. The committee or board should have members representing the regulated community, environmental community and general public.

The program could be phased in: fees per ton of emissions of specified pollutant(s) could gradually be increased over 5-10 years. The program could be based on existing permitting systems: fees would be based on the number of tons reported emitted, via existing reporting requirements within permits or any other existing framework for reporting.

III. Feasibility of the option

Emissions funds for air pollution are used in France, Japan and many states as well. There are no technical feasibility issues associated with this option.

IV. Background data and assumptions used

Stavins, R. (Ed.) (2000). *Economics of the Environment (4th Ed.)*. WW Norton: New York, New York.
New Hampshire Code of Administrative Rules, Chapter Env-A 3700: *NOx Emissions Reduction Fund for NOx-Emitting Generation Sources*.

Ohio EPA *Synthetic Minor Title V Facility Emission Fee Program*. http://www.epa.state.oh.us/dapc/synmin.html. (via statute--need cite).

Texas Administrative Code, Title 30, Part 1, Chapter 101, Subchapter A, Rule sec. 101.27: *Emissions Fees*

V. Uncertainty

VI. Level of agreement within workgroup

VII. Cross-over issues to other workgroups

The oil and gas industry could be subject to the emissions fund.

PROPOSED POWER PLANTS: DESERT ROCK ENERGY FACILITY

Mitigation Option: Desert Rock Energy Facility Stakeholder Funding to and Participation in Regional Air Quality Improvement Initiatives such as Four Corners Air Quality Task Force

I. Description of the mitigation option

Sithe Global and other stakeholders in Desert Rock Energy Facility will provide time and resource commitments to participate in inter-agency environmental initiatives to improve air quality in the Four Corners area.

Background:
Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). There are concerns, however, with air pollution in the area and the effects on human health, visibility, and other air quality related values. The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (3). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

While the Desert Rock Energy Facility is using newer environmental emission control technology that on average have higher reduction efficiencies than existing facilities, the proposed power plant will still be adding substantial NO2, SO2, particulate, and other emissions to the Four Corners Area. See appendix 1.

Industry support would help to provide the resources necessary to ensure the air quality in the Four Corners, including our National Ambient Air Quality Standards (NAAQS) attainment, is maintained. There are substantial stakeholder interests in having air quality cleaner than simply meeting the NAAQS, for example, to improve visibility.

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period. Desert Rock's comments included a discussion of a Voluntary Regional Air Quality Improvement Plan, CO2 emissions, and IGCC in relation to the proposed facility. The comments are located in an appendix at the end of the Power Plants section.

Benefits: Environmental initiatives will be supported by industries that contribute to the air quality issues. Much needed financial support will be provided to regional environmental initiatives. Information resources will be provided to help in the environmental regulation planning process.

Tradeoffs: None

Burdens: Sithe Global and other stakeholders will provide time and resource commitment to participate in inter-agency environmental initiatives in the Four Corners area.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary or mandatory

Differing Opinion: Mandatory: because of the fact that the Four Corners Area is already heavily polluted by several industrial sources such as the Four Corners Power Plant and the San Juan Generating Facility, over 19,000 oil and gas wells (over 12,500 new wells are planned in the next two decades), a fast growing population, more motor vehicles, etc.

B. Indicate the most appropriate agency(ies) to implement
Environmental Protection Agency (EPA) Air Programs
Desert Rock Energy Project voluntary participation

Differing Opinion: According to an article in the December 11, 2006 "Farmington Daily Times" titled "Navajo Nation to Partially Own Desert Rock", "Representatives from the Dine Power Authority (DPA) say they will operate the proposed Desert Rock Power Plant with at least one degree of separation from the Navajo Nation Environmental Protection Agency (NNEPA) which will have oversight of the project." This should be a major concern. The Desert Rock Power Plant if built, must be closely monitored and enforcement must be very strict. There are concerns that a conflict of interest may exist. The Federal EPA should be the governing agency.

III. Feasibility of the option
Feasible.

IV. Background data and assumptions used
Literature cited
(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)
(2) 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10
(3) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)

V. Any uncertainty associated with the option
Low.

VI. Level of agreement within the work group for this mitigation option.
To Be Determined.

VII. Cross-over issues to the other Task Force work groups
None.

Table 1. Estimated Maximum Annual Potential Emissions from Desert Rock Energy Facility [Source: AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)]

Pollutant	PC Boilers (tpy)	Auxiliary Boilers (tpy)	Emergency Generators (tpy)	Fire Water Pumps (tpy)	Material Handling (tpy)	Project Estimated Emissions
NOx	3,315	7.13	2.26	0.41	n/a	3,325
CO	5,526	2.55	0.17	0.031	n/a	5,529
VOC	166	0.17	0.11	0.019	n/a	166

SO2	3,315	3.61	0.068	0.012	n/a	3,319
PM[2]	553	1.02	0.083	0.015	16.1	570
PM10[3]	1,105	1.68	0.077	0.014	12.9	1,120
Lead	11.1	0.00064	0.00012	0.0000022	n/a	11.1
Fluorides	13.3	neg	neg	neg	neg	13.3
H2SO4	221	0.062	0.002	0.0004	n/a	221
Mercury	0.057	0.000071	neg	neg	n/a	0.057

[1]tpy -tons per year
[2]PM is defined as filterable particulate matter as measured by EPA Method 5.
[3]PM_{10} is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. EPA is treating PM_{10} as a surrogate for $PM_{2.5}$.

Mitigation Option: Emissions Monitoring for Proposed Desert Rock Energy Facility to be used over Time to Assess and Mitigate Deterioration to Air Quality in Four Corners Area

I. Description of the mitigation option

The present proposed monitoring permit requirements for Desert Rock Energy Facility address only measurement of permit standards while there is another category of monitoring which could and should be done. This category would be data needed or useful for the evaluation of mitigation options in the present or the future.

PROPOSED ADDITIONAL MONITORING

a. PM2.5 continuous monitoring requirement.

The Four Corners region has several class 1 areas and a long term requirement by the EPA for improving visibility. PM2.5 is a critical element in this problem and future mitigation of it will require precise knowledge of the relative contributions from multiple and varied sources. This could come about by inclusion in the EPA permit conditions or by the company adding it to what they are doing to protect themselves from future finger pointing. Either way the data needs to be publicly available so those evaluating mitigation options have the use of it.

Total filterable PM CEMs have been certified by EPA. EPA contends that there is no currently certified method to continuously monitor PM_{10} or $PM_{2.5}$. However, there are some PM CEMs vendors that suggest CEMS can be modified to monitor a certain particulate size fraction.

b. Speciated Mercury (Hg) stack emission plus a plume contact measurement.

This region now has several lakes where restrictions of fishing exist because of Hg levels in the fish. The sources of Hg are multiple (geology, mining, oil & gas, agriculture, and power plants) to devise a proper mitigation plan the Hg species will need to be known so that sources can be identified and contribution determined. Models which predict Hg species in the environment from those found in the stack have shown problems. (Hg Speciation in Coal-fired Power Plant Plumes Observed at Three Surface Sites in the SE U.S.,Environ. Sci. Technol.2006, 40, 4563-4570:Modeling Hg in Power Plant Plumes, Environ. Sci. Technol,2006, 40,3848-3854) For this reason sampling at plume ground contact needs to be done to determine species for our environment and plant and coal types as the Hg enters the environment since we can not count on modeling to give correct Hg speciation. The stack sampling should be required under the permit plume surface contact samples however might be a cooperative venture between state or tribal personnel and the company. (State or Tribal personnel taking the sample and this sample then run by the company with the stack sample.)

c. VOC sampling in addition to that presently specified in the permit.

While the VOC's are nowhere near levels that would cause general health problems they are critical to the processes involved in the visibility problem which needs addressing. VOC's react in the plume after emission and change. A measurement of the VOC's after the initial reaction in the plume would be advantageous since it would give what is present to react to give the visibility problems. The VOC's present after this initial reaction is usually predicted by modeling however the literature indicates there are some problems with this approach measurements made at the plume ground contact could be a joint operation. State or Tribal personnel might collect a sample with the company running the sample with their stack sample.

II. Description of how to implement

A. Mandatory or voluntary

Desert Rock Energy Facility would be responsible for facility monitors

There are concerns that there are not enough monitors in place in the Four Corners Area and that the existing monitors are not placed in optimum locations. Several more monitors in logical locations must be installed in order to accurately measure emissions. The Federal, State, and Tribal EPA agencies should be responsible for collection and analyzing samples. The Four Corners Power Plant and the San Juan Generating Station are among the dirtiest coal fired power plants in the Nation. Desert Rock must be placed under strict scrutiny. The Four Corners Area is already close to ground level ozone levels of non-attainment. The area cannot afford further degradation of the air quality.

B. Indicate the most appropriate agency(ies) to implement
State or Tribal personnel might collect and analyze some samples

III. Feasibility of the option
A. Technical
B. Environmental
C. Economic

*Monitoring Work Group – assess the feasibility (technical, environmental, and economic) of conducting the proposed monitoring.
*Cumulative Effects Work Group – Will the proposed additional monitoring in this mitigation option be useful in assessing the Desert Rock Energy Facility point source contributions to the cumulative Four Corners area air quality?

IV. Background data and assumptions:

V. Any uncertainty associated with the option (Low, Medium, High)
Low

VI. Level of agreement within the work group for this mitigation option
TBD

VII. Cross-over issues to the other source groups
None

Mitigation Option: Coal Based Integrated Gasification Combined Cycle (IGCC)

<u>I. Description of the mitigation option</u>
Consideration of IGCC technology, as an alternative to a pulverized coal fired boiler, should be considered in the BACT analysis.

Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). There are concerns, however, with air pollution in the area and the effects on human health, visibility, and other air quality related values. The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (2). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

On July 7, 2006, the Environmental Protection Agency (EPA) released a technical report titled "The Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies." The Report provides information on the environmental impacts and costs of the coal-based integrated gasification combined cycle (IGCC) technology relative to conventional pulverized coal (PC) technologies.

"IGCC is a power generation process that uses a gasifier to transform coal (and other fuels) to a synthetic gas (syngas), consisting mainly of carbon monoxide and hydrogen. The high temperature and pressure process within an IGCC creates a controlled chemical reaction to produce the syngas, which is used to fuel a combined cycle power block to generate electricity. Combined-cycle power applications are one of the most efficient means of generating electricity because the exhaust gases from the syngas-fired turbine are used to create steam, using a heat recovery steam generator (HRSG), which is then used by a steam turbine to produce additional electricity (3)."

Consideration of IGCC technology, as an alternative to a pulverized coal fired boiler, was not included in the BACT analysis for the Desert Rock Energy Facility (2).

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period. Desert Rock's comments included a discussion of IGCC. Please see the comment in its entirety in the appendix to the Power Plants section.

<u>Benefits:</u> For traditional pollutants such as nitrogen oxides (NOx), sulfur dioxide (SO2), particulate matter (PM) and mercury (Hg), IGCC is inherently lower polluting than the current generation of traditional coal-fired power plants. IGCC also has multi-media benefits, as it uses less water than Pulverized Coal facilities. IGCC also produces a solid waste stream that can be a useful byproduct for producing roofing tiles and as filler for new roadbed construction. IGCC also has the potential to reduce solid waste by using as fuel a combination of coal and renewable biomass products (3).

IGCC is considered one of the most promising technologies to reduce the environmental impacts of generating electricity from coal. EPA has undertaken several initiatives to facilitate the development and deployment of this technology

IGCC thermal performance (efficiency and heat rate) is significantly better than current generation pulverized coal technologies in the US;

The Capture of CO2 emissions from IGCC plants would be cheaper and less energy intensive than in conventional coal plants (3, 6)

<u>Tradeoffs:</u>
<u>Burdens:</u> IGCC has 10 – 20 % higher capital costs than conventional PC plants [3]
When carbon capture becomes mandatory, that cost disadvantage will likely disappear.

<u>II. Description of how to implement</u>
<u>A. Mandatory or voluntary</u>
Mandatory to look at IGCC as a Best Available Control Technology option for future power plants in the Four Corners area

Permit levels could be set based upon IGCC performance. It would be up to the source how to meet those limits with whatever technology it chooses.

This could be a new legislative requirement at the State or Tribal level

<u>B. Indicate the most appropriate agency(ies) to implement</u>
Policy options for use of Integrated Gasification Combined Technology could be developed by Environmental Protection Agency (EPA), Department on Energy (DOE), New Mexico Energy, Minerals, and Natural Resources Department (NMEMNRD).

*EPA could designate IGCC as a Best Available Control Technology.

Differing Opinion:
Assuming that coal gasification is an innovative fuel combustion technique for producing electricity from coal, EPA does not believe Congress intended for an "innovative fuel combustion technique" to be considered in the BACT review when application of such a technique would redesign a proposed source to the point that it becomes an alternative type of facility. In prior EPA decisions and guidance, EPA does not consider the BACT requirement as a means to redefine the basic design of the source or change the fundamental scope of the project when considering available control alternatives. Therefore, the question is whether IGCC results in a redefinition of the basic design of the source if the permittee is proposing to build a supercritical pulverized coal (SCPC) unit. EPA's view is that applying the IGCC technology would fundamentally change the scope of the project and redefine the basic design of the proposed source if a supercritical pulverized coal unit was the proposed design. Accordingly, consistent with our established BACT policy, we would not require an applicant to consider IGCC in a BACT analysis for a SCPC unit. Thus, for such a facility, we would not include IGCC in the list of potentially applicable control options that is compiled in the first step of a top-down BACT analysis. Instead, we believe that an IGCC facility is an alternative to an SCPC facility and therefore it is most appropriately considered under Section 165(a)(2) of the CAA rather than section 165(a)(4).

Four Corners state legislatures and/or Tribal Nations could legislate that IGCC be considered?

<u>III. Feasibility of the option</u>

A. Technical:
Development and implementation of IGCC technology is relatively new compared with the PC technology that has hundreds or thousands of units in operation globally. Currently in the US there are two gasification unit installations using coal to make electric power as the primary product. The two IGCC plants in commercial operation include the Tampa Electric Polk Power Station in Florida and the Wabash River Coal Gasification Repowering Plant in Indiana. Each has been in operation since the mid-1990s. Recently, however, a number of companies have announced plans to build and operate additional IGCC facilities in the US (3).

These plants have yet to maintain better than 80% availability after more than 10 years of operation. Improved process control strategies are needed to ensure optimum operation over the full range of operating conditions. Real time coal quality analysis is needed to stabilize the coal gasifier process. Several areas of instrumentation development are warranted by the challenging physical conditions of the high temperature, abrasive, slagging gasifier environment. Other areas of the IGCC process face unique challenges that require development efforts to achieve the high availability rate needed for economic viability.

IGCC plants have not been demonstrated larger than 300 MW. For Desert Rock, more/larger gasifiers and several combustion turbines would be needed to attain 1500 MW. This technology is promising, but needs much development funding before the investment community would take on the risk of building such a large IGCC facility.

B. Environmental: This is a process control option

C. Economic: IGCC has higher capital costs than conventional PC plants (3).

IGCC has not demonstrated the typical 85-95% PC plant availability factors necessary for viable on-going profitable operation.

Historically, concerns about operational reliability and costs presented issues of uncertainty for IGCC technology and impeded its deployment. Such conditions are changing toward the more rapid advancement of the IGCC option. IGCC is a versatile technology and is capable of using a variety of feed stocks. In addition to various coal types, feed stocks can include petroleum coke, biomass and solid waste. Along with electricity production, IGCC facilities are able to co-produce other commercially desirable products that result from the process. Some of these products include steam, oxygen, hydrogen, fertilizer feed stocks and Fischer-Troph fuels (3).

The operational versatility noted above for IGCC technology may mitigate the risk of higher costs. In addition, under the Energy Policy Act of 2005, there are provisions for tax credits and a DOE Loan Guarantee Program to provide incentives to facilitate the deployment of IGCC technology.
In 1994 EPA established the Environmental Technology Council (ETC) to coordinate and focus the Agency's technology programs. The ETC strives to facilitate innovative technology solutions to environmental challenges, particularly those with multi-media implications. The Council has membership from all EPA technology programs, offices, and regions and meets on a regular basis to discuss technology solutions, technology needs and program synergies. One of the technologies identified as a promising option to address the production of energy from coal in an environmentally sustainable way is IGCC. This technical report is part of the ETC initiative and supports the combined efforts of EPA and the Department of Energy to advance the use of IGCC technology (3).

IV. Background data and assumptions used:

(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)

(2) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)
(3) Technical Report on the Environmental Footprint and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, Fact Sheet: http://www.epa.gov/airmarkets/articles/IGCCfactsheet.html
(4) Wabash River IGCC Topical Report 2000 – www.fossil.energy.gov/programs/powersystems/publications/Clean_Coal_Topical_Reports/topical20.pdf
(5) Pioneering Gasification Plants (DOE) – http://www.fe.doe.gov/programs/powersystems/gasification/gasificationpioneer.html
(6) Scientific American, September 2006 article, "What to do about Coal," pp. 68-75
(7) ISA-2005 "I & C Needs of Integrated Gasification Combines Cycles" Jeffrey N. Phillips, Project Manager, Future Coal Generation Options, Electric Power Research Institute – presented at the 15th Annual Joint ISA POWID/EPRI Controls and Instrumentation Conference, 5-10 June 2005, Nashville, TN

V. Any uncertainty associated with the option

Medium. Integrated Gasification Combined Cycle (IGCC) is still a relatively new technology. There are coal gasification electric power plants in the US and other nations.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups:

None

Mitigation Option: Desert Rock Energy Facility Invest in Carbon Dioxide Control Technology

I. Description of the mitigation option

Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (2). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

CO_2 emissions are not regulated; however, they are the primary Greenhouse gas that causes global warming.

In June 2005, the Climate Change Advisory Group was created in New Mexico as the result of an executive order from the Governor. The Climate Change Advisory Group (CCAG) is tasked with preparing an inventory of current state (New Mexico) Greenhouse gas emissions, as well as a forecast of future emissions. An action plan with recommendations to reduce Greenhouse gas emissions in New Mexico is also being prepared (3).

The process of generating electricity is the single largest source of greenhouse gas emissions in the United States (34 percent) [4]. CO_2 emissions. The Desert Rock Energy Facility will contribute approximately 11,000,000 Tons/yr CO_2 emissions (5, 6).

Desert Rock is a new proposed power plant in the Four Corners area. Technology is now available to capture and store CO_2 emissions. Many of these technologies are easier and less expensive if integrated into the design and construction of the power plant, rather than added later as retrofits. Retrofitting generating facilities for Carbon Capture and Storage (CCS) is inherently more expensive than deploying CCS in new plants (7).

CO2 capture and storage involves capturing the CO2 arising from the combustion of fossil fuels, as in power generation, or from the preparation of fossil fuels, as in natural-gas processing. Capturing CO2 involves separating the CO2 from some other gases. For example in the exhaust gas of a power plant other gases would include nitrogen and water vapor. The CO2 must then be transported to a storage site where it will be stored away from the atmosphere for a long period of time. In order to have a significant effect on atmospheric concentrations of CO2, storage reservoirs would have to be large relative to annual emissions. (IPCC, 2001)

This mitigation option is for Desert Rock Energy Facility and any other proposed power plants to invest into CO_2 emissions control and capture technologies. Desert Rock is in a unique situation to set an example and take the lead in this emissions reduction field.

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period including a discussion of CO2 emissions. The comments are located in an appendix at the end of the Power Plants section.

Benefits: Reduced CO_2 emissions
Tradeoffs: None
Burdens: CO_2 control technology is expensive. Burden would be on the power plant; however, there may be some funding for the innovative technologies that would be used.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary

Differing Opinion: According to experts, Desert Rock, if built, would be the seventh largest source of greenhouse gas pollution in the Western United States. It is expected that Desert Rock will emit over 11million tons of carbon dioxide per year. Emission controls on carbon dioxide will most likely be required in the very near future. Carbon dioxide emission reduction technology should be mandatory on the Desert Rock facility.

B. Indicate the most appropriate agency(ies) to implement
Environmental Protection Agency (EPA) Region 9 Air Program
Navajo Nation Air Programs
Industry leadership

EPA Climate Protection Partnership is a possible or New Mexico's San Juan Voluntary Innovative Strategies for Today's Air Standards (VISTAS) are possible vehicles for this mitigation option.

III. Feasibility of the option
A. Technical: Technologies exist; many are in the research and development phase. Technological components are commercially ready in unrelated applications (7).

B. Environmental: Capturing and storing CO_2 emissions is difficult. Integrated systems have yet to be constructed at necessary scales. Feasibility question remains whether CO_2 could be stored without substantial leakage over time

C. Economic: Capturing and storing CO_2 emissions can be expensive.

IV. Background data and assumptions used
(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)
(2) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)
(3) Climate Change Advisory Group (CCAG) homepage: http://www.nmclimatechange.us/index.cfm
(4) EPA Climate Protection Partnerships: http://www.epa.gov/cppd/other/energysupply.htm
(5) 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10
(6) San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
(7) Scientific American, September 2006 article, "What to do about Coal," pp. 68-75

V. Any uncertainty associated with the option High

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None

Mitigation Option: Federal Land Manager Mitigation Agreement with Desert Rock Energy Facility

I. Description of option

Background

Sithe Global Energy (Sithe) is proposing the Desert Rocky Energy Facility (DREF) on the Navajo Nation in northwestern New Mexico. The proposed facility would be within 300 km of 27 National Park Service units, nine of which are Class I areas, and six are U.S. Forest Service Class I areas. The proposed facility will have two 750 megawatt pulverized-coal boilers, and would be well-controlled for a coal-fired power plant. SO2 emissions would be controlled to 3,315 tons per year with Wet Limestone Scrubbers, and NOx emissions would be controlled to 3,315 tons per year with Low-NOx burners and Selective Catalytic Reduction. Despite these controls, the National Park Service and U.S. Forest Service have concluded that the emissions from DREF, absent mitigation measures, would have an adverse impact on visibility at four or more Class I areas in the region. There are also concerns with the emissions contributing to cumulative negative impacts in the region as a whole.

The permitting authority for the Desert Rock Energy Facility is the Environmental Protection Agency (EPA) Region 9, because the facility would be located on the Navajo Reservation, where neither the State of New Mexico (or Arizona) nor the Navajo Nation have permitting authority. For over two years, the National Park Service and the U.S. Forest Service worked closely with Sithe, EPA and tribal representatives to ensure the potential impact of the proposed facility were carefully analyzed. When it became evident that emissions from the facility could adversely impact visibility in several Class I areas, the energy company suggested mitigation measures intended to produce a net environmental improvement in the area, notwithstanding construction and operation of the DREF. Sithe and the federal land managers (FLMs) both sought to avoid a formal adverse impact determination that would jeopardize the issuance of the air quality permit. Negotiations ensued and resulted in an agreement in principle on substantive mitigation measures in April of 2006.

In July, 2006, EPA issued a proposed PSD permit for the facility but did not include the agreed-upon mitigation measures. EPA reasoned that mitigation measures should not be included as part of the permit absent a formal declaration of adverse impact by the FLM.
Both the National Park Service and the U.S. Forest Service have asked EPA to include the mitigation measures in the PSD permit. In the absence of the terms of the agreement in principle included as part of the final PSD permit, Task Force members are interested in ensuring the measures will be put in place to avoid adverse impacts to air quality related values in Class I areas and the region as a whole will be avoided throughout the life of the facility.

Sulfur Dioxide Mitigation

The following options outline the sulfur dioxide mitigation strategy for the DREF. The choice between Option A or Option B shall be made by Sithe or its assigns prior to the commencement of DREF plant operations.

Option A: For the purposes of mitigating potential air quality impacts, including potential visibility and acid deposition impacts, of the DREF at Class I and Class II air quality areas in the region potentially affected by DREF, Sithe[1] shall develop or cause to be developed a capital investment project or projects that generate Emission Reduction Credits from physical and/or operational changes that result in real emission reductions at one or more Electric Generating Units[2] (EGUs) within 300 km of the DREF and retire sulfur dioxide[3] Allowances in accordance with the following:

- The number of sulfur dioxide Emission Reduction Credits required for the respective calendar year shall be determined by DREF's actual sulfur dioxide emissions, in tons, plus 10%, measured as set forth in the next paragraph below.
- The amount of Emission Reduction Credits achieved would be determined by comparing the emission rate (in tons) during the year for which the reduction is claimed to a baseline emission rate. The baseline emission rate shall be the average emission rate (in tons per year) during the two-year period prior to any emission reduction taking place.
- Acceptable sulfur dioxide Emission Reduction Credits under this condition shall be allowances originating from facilities that were allocated sulfur dioxide Allowances under 40 CFR 73[4] and that are located within 300 km of the DREF facility.
- The vintage year of the Emission Reduction Credits shall correspond to the year that is being mitigated. Sithe shall retire the required Emission Reduction Credits by transferring an equivalent number of Allowances into account #XXX with the U.S. EPA Clean Air Markets Division[5]. Except for Sithe's purposes under Title IV, these retired Allowances can never be used by any source to meet any compliance requirements under the Clean Air Act, State Implementation Plan, Federal Implementation Plan, Best Available Retrofit Technology requirements, or to "net-out" of PSD. However, surplus Emission Reduction Credits could be used at the discretion of the holder of the credits.
- Sithe shall submit a report to the EPA Region 9 Administrator (or another party acceptable to the Federal Land Managers) no later than 30 days after the end of each calendar year which shall contain the amount of sulfur dioxide emitted; amount, facility, location of facility, vintage of Emission Reduction Credits retired; proof that Emission Reduction Credits/Allowances have been transferred into account #XXX; and any applicable serial or other identification associated with the retired Emission Reduction Credits/Allowances.

Due to the actual emission reductions obtained from nearby sources under this Option, the Federal Land Managers prefer this approach to mitigating DREF's air quality impacts.

Or,

Option B: For the purposes of mitigating potential air quality impacts, including potential visibility and acid deposition impacts, of the DREF at Class I and Class II air quality areas in the region potentially affected by DREF, Sithe shall obtain and retire sulfur dioxide "Mitigation Allowances" from one or more EGUs within 300 km of the DREF in accordance with the following:

- In addition to those Allowances required under Title IV, the required number of sulfur dioxide "Mitigation Allowances" for the respective calendar year shall equal DREF's actual total sulfur dioxide emissions, in tons.
- Acceptable sulfur dioxide "Mitigation Allowances" under this condition shall be from facilities that were allocated sulfur dioxide Allowances under 40 CFR 73 and that are located within 300 km of the DREF. However, the total annual cost of "Mitigation Allowances" purchased beyond those regular Allowances required by Title IV is not to exceed three million dollars[6]. Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain physical emission reductions at sources not granted allowances under 40 CFR 73.
- The vintage year of the "Mitigation Allowances" shall correspond to the year that is being mitigated. Sithe shall retire these "Mitigation Allowances" by transferring them into account #XXX with the U.S. EPA Clean Air Markets Division. These retired "Mitigation Allowances" beyond Title IV can never be used by any source to meet any compliance requirements under the Clean Air Act, State Implementation Plan, Federal Implementation Plan, Best Available Retrofit Technology requirements, or to "net-out" of PSD.

- Sithe shall submit a report to the EPA Region 9 Administrator (or another party subject to approval of the Federal Land Managers) no later than 30 days after the end of each calendar year which shall contain the amount of sulfur dioxide emitted from the DREF; amount, facility, location of facility, vintage of Allowances retired; proof that Allowances have been transferred into account #XXX; and any applicable serial or other identification associated with the retired Allowances.

Additional Air Quality Mitigation
If Sithe chooses Option A, it will contribute $300,000 annually toward environmental improvement projects that would benefit the area affected by emissions from DREF, including the Class I areas and the Navajo Nation. If Sithe chooses Option B, it will contribute toward environmental improvement projects an amount equal to the $3 million cap described under Option B above, minus the cost of the Mitigation Allowances, up to a maximum of $300,000. Appropriate projects will be determined jointly by the Federal Land Managers, Navajo Nation EPA, the Desert Rock Project Company and Diné Power Authority, and may include projects that would reduce or prevent air pollution or greenhouse gases, purchasing and retiring additional emission reduction credits or allowances, or other studies that would provide a foundation for air quality management programs. Up to 1/5 of the contributions can be dedicated to air quality management programs. The remaining contributions shall be used to support projects that mitigate greenhouse gas emissions or criteria pollutants impacts. The Desert Rock Project Company shall have the ability to bank the emission reduction credits achieved through these projects and be entitled to these credits to comply with future greenhouse gas emission mitigation programs. Mitigation and contributions toward environmental improvement projects shall not occur before operation of the Desert Rock Energy project begins.

And,

Sithe will reduce mercury emissions by a minimum of 80% on an annual average using the air pollution control technologies as proposed in the permit application, i.e. SCR, wet FGD, hydrated lime injection, and baghouse. In addition, Sithe will raise the mercury control efficiency to a minimum of 90% provided that the incremental cost effectiveness of the additional controls (such as activated carbon injection or other mercury control technologies) does not exceed $13,000/lb of incremental mercury removed. Compliance with this provision will be determined by installation and operation of an EPA-approved mercury monitoring and/or testing program. In operating periods when a minimum of 80% mercury control (or 90% as noted above) is not technically feasible due to extreme low mercury concentrations in the burned coal, Sithe will work with EPA to establish a stack mercury emission limit in lieu of a percent reduction, for the purposes of demonstrating compliance.

Examples of Mitigation Strategies

Example #1:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option A, Sithe would be required to reduce SO_2 emissions at another source (or sources) within 300 km by 3,300 tons. These credits can be used to meet the requirements of the acid rain program under Title IV of the Federal Clean Air Act provided that the physical and/or operational change occur on one or more EGUs.

Example #2:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option A, suppose Sithe reduces SO_2 emissions at another source (or sources) within 300 km by 4,000 tons. In this case, Sithe would have created 700 tons of surplus SO_2 Emission Reduction Credits that it may use as it sees fit.

Example #3:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option B, Sithe would purchase its “regular” 3,000 tons of Title IV Allowances from any source, anywhere, plus up to 3,000 tons of SO_2 “Mitigation Allowances” from another source (or sources) within 300 km, provided that the total cost of the “Mitigation Allowances” does not exceed $3 million (in 2006 dollars). If each “Mitigation Allowance” costs at least $1,000, Sithe would be done.

Example #4:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option B, Sithe would purchase its “regular” 3,000 tons of Title IV Allowances from one or more EGU sources. For the remaining 3000 SO2 “Mitigation Allowances”, Sithe may choose, as an option, to obtain 9000 NOx emission reduction credits from physical or operational changes of one or more NOx emission sources within 300 km.

Example #5:
Suppose Sithe obtains the necessary SO_2 reductions through a capital investment project (Option A), or purchases SO_2 Mitigation Allowances (Option B) at a cost of $2.7 million or less. Sithe would then contribute the maximum $300,000 to the environmental improvement fund because the total annual costs (allowances plus contribution) would be below the $3 million cap. On the other hand, if the mitigation allowances cost more than $2.7 million, Sithe would contribute the difference between the $3 million cap and the actual cost of the Mitigation Allowances (i.e., if allowance costs equal $2.9 million, the environmental improvement fund contribution would be $100,000).

Implementation
The clearest way for these measures to be implemented would be to include them in the PSD permit. Since EPA Region 9 is the permitting authority in this case, that agency would be responsible for including the measure in the permit. Absent including the measures in the permit, other ways of ensuring the mitigation measure will take place are being explored. The FLMs prefer that the mitigation measures be federally enforceable regardless of the mechanism ultimately used.

III. Feasibility of the option
By agreeing to the mitigation measures, Sithe has implicitly affirmed the feasibility of the measures. Incorporation into a permit is feasible for the permitting authority as long as the measure does not contradict any statutory or regulatory provision.

Background Data and Assumptions
The suggested mitigation measures are taken from the agreement-in-principle between Sithe Global Power and the FLMs. Estimated emissions from DREF come from the draft permit.

V. Any uncertainty associated with the option
The uncertainty in this option involves how stakeholders can be assured the measures will actually happen.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

Citations:
[1] References to Sithe include its subsidiary "Desert Rock Energy Company, LLC" which will be the owner of DREF (referred to herein as the Desert Rock Project Company).
[2] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain real emission reductions at sources other than EGUs.

[3] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining and tracking emission reductions, nitrogen oxides reductions may be substituted for sulfur dioxide reductions by a ratio of three tons of nitrogen oxides to one ton of sulfur dioxide.
[4] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain physical emission reductions at sources not granted allowances under 40 CFR 73.
[5] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining and tracking Emission Reduction Credits, Sithe may obtain real emission reductions at sources other than EGUs. Nitrogen oxides reductions may be substituted for sulfur dioxide reductions by a ratio of three tons of nitrogen oxides to one ton of sulfur dioxide.
[6] All costs referenced in this document are base-year 2006 dollars that will be adjusted for inflation by using the consumer price index.

FUTURE POWER PLANTS

Mitigation Option: Integrated Gasification Combined Cycle (IGCC)

I. Description of the mitigation option

Energy related projects in the Greater Four Corners Region (NM, CO, AZ, UT and WY) are expected to continue to grow at or above current rates. Population and related commerce growth in the 12 county local Four Corners Region (NM, CO, AZ, UT) grew at a brisk rate of 23.8% during the 1990s (1). Future electric power demand will require new power plants and transmission grid capacities. Alternative future "clean coal" power generation technologies such as, FutureGen, Integrated Gasification Combined Cycle (IGCC), and advanced fossil fuel power plants (with carbon capture and sequestration (CCS) technologies) and renewable energy facilities (e.g., wind farms, solar arrays, …) will be needed to accommodate this growth, as well as the increasing demand outside the Four Corners area. Given the size of the western coal reserve and its relatively inexpensive cost compared to natural gas, commercial IGCC power plants could potentially play a role in meeting the region's future "clean" power needs.

Overview: A power plant based on IGCCtechnology combines or integrates a coal gasification system (gasifier and gas clean-up systems) with a highly efficient combined cycle power generation system. There are a variety of coal gasification technologies in various stages of development that are designed to produce clean synthesis gas (syngas) from coal. The combined cycle unit includes a gas turbine set consisting of a compressor, burner and the gas turbine coupled with a heat recovery steam generator (HRSG). The steam generated in the HRSG, as well as any excess steam generated in the gasification process that is not used elsewhere in the system, is used to power a steam turbine. An IGCC unit has the potential to achieve similar environmental benefits and thermal performance as a natural gas fired combined cycle power generation unit. The use of relatively low cost coal as a feedstock is the one of the main advantages of coal-based power plants. The ability of an IGCC unit to use coal while generating lower air emissions than conventional coal technologies has lead to increased interest in the technology. While IGCC is a promising technology, it has not completely commercially developed. Two small 260 MWe IGCC plants, the Wabash River Plant in Indiana and the Polk Plant in Florida, have been operating for over a decade. Originally built as demonstration plants, reliability of the IGCC units has generally improved over time with gasifier capacity factors in the range of 80% demonstrated in a number of years (2). (Note: the Polk Power Station IGCC unit has only had one year of operation where the gasifier CF was greater than 80% and two years where the CF was near 80% in the 10+ years of operation.) Currently there are at least five separate permit applications for commercial size IGCC plants in the continental United States. Four of these applications are for plants exceeding 600 MWe nominal capacity.

The operation of the major chemical and mechanical process components of a typical coal based IGCC power plant can be summarized as follows (3):

- The gasifier produces syngas by partially oxidizing coal in presence of air or oxygen.
- The ash in the coal is converted to inert, glassy slag.
- The syngas produced from the gasifier is cooled.
- The syngas is cleaned to remove particles.
- The slag and other inert material are collected to be used to make some products or can be safely discarded in the landfill.
- The mercury is removed by passing syngas through the bed of activated carbon.
- The sulfur removed from the syngas is converted into elemental sulfur or sulfuric acid for sale to chemical or fertilizer companies.
- The clean syngas can either be burned in a combustion turbine/electric generator to produce electricity or used as a feedstock for other marketable chemical products.

- Steam produced in the HRSG from the hot combustion turbine exhaust, as well as additional steam that has been generated throughout the process, drives a steam turbine to produce additional electricity.
- The stream exhausted from the steam turbine is cooled and condensed back to water. The water is then pumped back into the steam generation cycle.

Benefits:

- For traditional pollutants such as nitrogen oxides (NOx), sulfur dioxide (SO_2), particulate matter (PM) and mercury (Hg), IGCC is lower polluting than the current generation of traditional coal-fired power plants. It is potentially as "clean" a NOx emitter (< 0.3 lb/MW-hr) as for NGCC plants (4).
- The removal of sulfur compounds, particulates and mercury is more efficient in an IGCC because the removal can take place before the gas is burned (fuel gas) instead of removing the compounds from the exhaust gases following combustion (flue gas).
- The water requirement for the IGCC process is approximately one-third less than that of a pulverized coal plant.
- Solid waste generation at an IGCC power plant is less than that of a PC plant.
- IGCC plants are more flexible in terms of fuel feedstock because they can utilize a variety of fuels, such as coal, biomass, and refinery by-products such as petroleum coke (petcoke). In general, IGCC units are designed to use only one type of coal (i.e. bituminous, sub-bituminous or lignite), but can handle a variety of coals from within the same coal type.
- The CO_2 emissions from an IGCC unit can be higher than from a conventional coal power plant (3). However, based on current technology, it is believed that capture of CO_2 emissions from IGCC plants would be more energy efficient than capture from a conventional coal fired power plant.
- IGCC plants operate at efficiencies of about 40% but have the potential to be as high as 45% (or higher if fuel cells are used). By comparison, conventional combustion-based power plants have efficiencies that range from about 33% to 43%.

Burdens (or deployment barriers):

- General lack of commercial-scale operating experience, especially at Four Corners altitudes.
- Doubts about plant financial viability without subsidies. IGCC has significantly higher capital costs, nominally approximately 20% or higher than the cost for conventional PC plants (Wayland, 2006).
- Low plant reliability, demonstration of commercial plant reliability and capacity factor remains a concern.
- Without carbon capture, an IGCC can have a higher carbon footprint compared to a conventional PC plant. However, the lower total gas flow, the higher percentage of CO_2 in the gas stream, combined with the high operating pressure of the gas stream, makes it easier to recover CO_2 from the syngas in IGCC power plants than from flue gas in conventional coal power plants, based on current technology.
- IGCC carbon capture and sequestration (CCS) technologies have not yet been demonstrated at commercial scale. However, once CCS is demonstrated, IGCC has a potential advantage in capturing and sequestrating CO_2 at lower costs for the reasons stated in the bullet above.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary to look at IGCC as a future clean power generation option for future power plants in the Four Corners area.

B. Indicate the most appropriate agency(ies) to implement

Policy options for use of Integrated Gasification Combined Cycle Technology could be developed by Environmental Protection Agency (EPA), Department on Energy (DOE), State or Tribal Environmental Protection Agencies.

III. Feasibility of the option

A. Technical: There is some concern about the feasibility of IGCC power plants at high altitude, elevated temperatures and using western fuels. High altitudes and elevated temperatures lead to significant derations of the power output from the gas turbine portion of the IGCC unit. Turbine manufacturers are working on ways to overcome this altitude deration but, to-date, no solutions have been developed and/or demonstrated.

Carbon dioxide capture technology from IGCC units is still in its research and development phase. To be more cost competitive, a number of technology improvements will need to be made in IGCC plant design; including larger, higher pressure and lower cost quench gasifiers (6). In addition, new and improved gas turbines will be needed that enable air extraction across the operating range of ambient temperatures and with hydrogen firing (7).

Carbon capture and sequestration technologies have potential to substantially reduce carbon emissions into the atmosphere. However the given the current cost of carbon capture and sequestration technologies, it will not be viable solution without a carbon penalty. CO_2 sequestration is also a site-specific geological issue. Options to address this issue include:

- Locating the IGCC unit in an area suitable for geologic sequestration, EOR, EGR or ECBMR
- Pipe the captured CO_2 from an IGCC unit to an area suitable for geologic sequestration, EOR, EGR or ECBMR
- Gasify the coal close to an area suitable for geologic sequestration, EOR, EGR or ECBMR and then send the gas for the power production (although this option does not receive the efficiency benefits associated with a fully integrated IGCC unit).

Currently in the US there are two small IGCC plants, the Tampa Electric Polk Power Station in Florida and the Wabash River Coal Gasification Repowering Plant in Indiana, using coal to make electric power as the primary product. These plants were funded and built in the mid-1990s as demonstration plants by DOE. Recently, however, five companies have applied for and in few cases already received permits and at least five companies have announced plans or issued letters of intent to build and operate IGCC facilities in the US. American Electric Power is proposing to build two 629 MW power plants in Ohio and West Virginia – although the projects have been put on hold due to concerns over project cost escalation (as have several other utilities) (8). Xcel Energy is investigating building an IGCC plant with CO_2 capture and sequestration. Duke and Tampa Electric have received tax credits to help reduce the cost of building IGCC power plants under the Energy Policy Act of 2005.

B. Environmental: For traditional pollutants such as NOx, SO_2, PM and Hg, IGCC is inherently lower polluting than the current generation of traditional coal-fired power plants. There are a number of concerns related to the geologic sequestration of CO_2, whether or not the CO_2 is from an IGCC unit. These concerns include, but not limited to the following:

- How will geologic sequestration be permitted over the long-term, including demonstration studies and the duration of the sequestration permit (i.e. 5 year, life of facility, etc.)
- What measurement, monitoring and verification (MMV) techniques and requirements will be placed on the project
- How will the liability associated with the sequestered CO_2 be addressed
- How will the property rights associated with the sequestered CO_2 be addressed

- Will the injection of CO_2 into a deep saline aquifer prohibit the future use of water from that aquifer should in-land desalination prove to be cost-effective or necessary to address future water needs

C. Economic: IGCC has higher capital costs than conventional PC plants (9). Historically – and currently, concerns about operational reliability and costs presented issues of uncertainty for IGCC technology and impeded its deployment. IGCC can be a versatile technology and is capable of using a variety of feedstocks. In addition to various coal types, feedstocks can include petroleum coke, biomass and solid waste.

Along with electricity production, IGCC facilities, if designed to do so, can co-produce other commercially desirable products. Some of these products include steam, oxygen, hydrogen, fertilizer feed stocks and Fischer-Tropsch fuels (10).

There is not a consensus about the relative costs of carbon capture technology for various plants. General consensus is that, given current technology, it is less expensive to capture CO2 from IGCC plants than from any other coal-based plant, as well as NGCC plants (11). According to an MIT study, today the capital cost (in 1999 dollars?) of CO_2 capture and separation is \$1730/kW, which will reduce to \$1433/kW in 2012. The CO_2 capture and separation cost for a NGCC power plant is about \$1120/kW today, which will reduce to \$956/kW in 2012 (12). There are many uncertainties with regards to the costs of CCS.

The operational versatility noted above for IGCC technology may mitigate the risk of higher costs. In addition, under the Energy Policy Act of 2005, there are provisions for tax credits and a DOE Loan Guarantee Program to provide incentives to facilitate the deployment of IGCC technology.

IV. Background data and assumptions used:

(1) City of Farmington Draft Consolidated Plan, 2004, June
(2) Coal-Based IGCC Plants – Recent Operating Experience and Lessons Learned. Gasification Technologies Conference, Washington, DC (October 2006).
(3) Pioneering Gasification Plants (DOE): http://www.fe.doe.gov/programs/powersystems/gasification/gasificationpioneer.html
(4) Wayland, R.J., 2006, U.S. EPA's Clean Air Gasification Activities, Gasification Technologies Council, Winter Meeting January 26, Tucson, Arizona
(5) Blankinship, Steve. "Amid All the IGCC Talk, PC Remain the Go-To Guy." Power Engineering International.
(6) Revis, James, 2007, Clean Coal Technology Status: CO_2 Capture & Storage *Technology Briefing for COLORADO RURAL ELECTRIC ASSOCIATION, February 19*
(7) Wabash River IGCC Topical Report 2000 - www.fossil.energy.gov/programs/powersystems/publications/Clean_Coal_Topical_Reports/topical20.pdf
(8) American Electric Power permit application for proposed IGCC power plant in Great Bend, Ohio and Mountaineer, West Virginia. http://www.aep.com/about/igcc/technology.htm
(9) Technical Report on the Environmental Footprint and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, Fact Sheet: http://www.epa.gov/airmarkets/articles/IGCCfactsheet.html
(10) IGCC & CCS Background Document. 2006, State Clean Energy-Environment Technical Forum Integrated Gasification Combined Cycle (IGCC) Background and Technical Issues June 19
(11) Clayton, S.J., Stiegel, G.J., and Wimer, J.G., 2002, Gasification Technologies Product Team U.S. Department of EnergyU.S. DOE's Perspective on Long-Term Market Trends and R&D

Needs in Gasification 5th European Gasification Conference Gasification – The Clean Choice Noordwijk, The Netherlands April 8-10
(12) Herzog, Howard. "An Introduction to CO_2 Separation and Capture Technologies." MIT Energy Laboratory (1999).

V. Any uncertainty associated with the option (Low, Medium, High):
Medium to High, particularly when coupled with CCS as both are developing technologies.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups: None at this time.

Mitigation Option: Carbon (CO_2) Capture and Sequestration (CCS)

I. Description of the mitigation option

Carbon Capture and Sequestration (CCS) generally consists of removing carbon in the form of CO_2 from either the fuel gas stream; syngas of an Integrated Gasification Combined Cycle (IGCC) power plant or the flue gas stream of other fossil fuel power plants (i.e. pulverized coal, including supercritical pulverized coal (SCPC) and ultra-super critical pulverized coal (USCPC), and natural gas (NGCC) units) compressing and transporting the CO_2 to the sequestration site and sequestering the CO_2. Sequestration can consist of either injecting the CO_2 into a deep saline aquifers or using the CO_2 for enhanced oil recovery (EOR), enhanced natural gas recovery (EGR) or enhanced coal bed methane recovery (ECBMR). Utilization of CCS in combination with other mitigation options such as alternative fuels, energy efficiency and renewal energy would mitigate the potential greenhouse gas (GHG)/climate change impacts of using fossil fuels for power generation.

Overview:

Currently, there are two generic types of CO_2 removal solvents available:

- Chemical absorbents (i.e. amines) that react with the acid gases and require heat to reverse the reactions and release the CO_2
- Physical absorbents (i.e. Selexol and Rectisol) that dissolve CO_2

Amines: Amines are organic compounds that contain nitrogen as the key atom. Structurally, amines resemble ammonia. The advantage of an amine CO_2 removal system is that it has a lower capital cost than any of the current physical solvent processes. The disadvantage is that an amine system uses large amounts of steam heat for solvent regeneration and energy to re-cool the amine, making it a less energy efficient process.

Selexol: Selexol is the trade name for a physical solvent that is a mixture dimethyl ethers of polyethylene glycol. In the Selexol process, the solvent dissolves the CO_2 from the gas stream at a relatively high pressure, generally in the range of 300 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2. The Selexol process requires less energy than amine-based processes as long as the operating pressure is above 300 psia. At lower pressures, the amount of CO_2 that is absorbed per volume of solvent drops to a level that generally favors the use of an amine system.

Rectisol: Rectisol is the trade name for a CO_2 removal process that uses chilled methanol. In the process, methanol at a temperature of approximately –40 °F absorbs the CO_2 from the gas stream at a relatively high pressure, generally in the range of 400 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2. While the methanol solvent is less expensive than the Selexol solvent, the Rectisol process is more complex, has a higher capital cost and requires costly refrigeration to maintain the low temperatures required. It does, however, provide for the most complete removal of CO_2.

Cryogenic coolers are also currently shown to capture CO2 from the combustion exhaust. The cost of CO2 capture is generally estimated as three fourth of the whole carbon capture, storage, transport, and sequestration system. Currently the average cost of carbon capture is about $150/ton by using current technology is high for carbon emission reduction purposes (1). In order to transport and sequester the CO_2, the gas must be compressed to 2000 psia or higher. Research is underway to find better technologies for carbon capture. Presently, the most likely identifiable options apart from absorbents for the carbon separation and capture are (1):

- Adsorption (Physical and Chemical)
- Low-temperature Distillation
- Gas separation Membranes
- Mineralization and Biomineralization

Benefits:

- CO_2 that would otherwise be emitted to the atmosphere is sequestered.
- If used for Enhanced Oil Recovery (EOR), Enhanced Gas Recovery (EGR) or Enhanced Coal Bed Methane Recovery (ECBMR), the CO_2 from power plants is put to beneficial use and could replace some or all of the natural CO_2 that is currently used for those purposes as well as recover fossil fuel.

Burdens (or deployment barriers):

- Currently there are no power plants in the world that perform CCS, so the integration of the power plant technology with the CCS technology has yet to be proven.
- The capital and O&M costs for CCS are significant and adversely impact the cost of electricity (COE). The cost of electricity will increase by 2.5 cents to 4 cents/Kwh if current carbon capture technologies are added to electrical generation(1).
- No large-scale tests of deep saline aquifer injection have been performed to-date. The Sleipner project in Norway's North Sea is the world's first commercial carbon dioxide capture and storage project(2). CO2 is extracted from gas production on Statoil's Sleipner West Field in the Norwegian North Sea. Started in 1996, it sequesters about 2800 tons of carbon dioxide each day and injects into Utsira sandstone formation (aquifier)(3).
- No environmental laws, rules or procedures are in place for CCS projects.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary in the near term; mandatory as laws, rules and procedures are established.

B. Indicate the most appropriate agency(ies) to implement

Environmental Protection Agency (EPA), Department on Energy (DOE), State Environmental Protection Agencies.

III. Feasibility of the option

A. Technical:

IGCC

In IGCC power plants, CO_2 can be captured from the synthesis gas after the gasification process before it is mixed with air in a combustion turbine. The CO_2 is relatively concentrated (50 volume %) and at high pressure which provides the opportunity for lower cost for carbon capture (4).

While proven carbon capture technology is available for IGCC plants, there are currently no IGCC facilities in the world that capture, compress and sequester CO_2. Depending on the IGCC technology and the carbon capture technology used, it is estimated that carbon capture and compression could add 35 - 50% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2, both from a demonstration (pre-permitting) and ongoing operations perspective.

A number of IGCC technology vendors are working on improvements to their gasifiers that allow for easier CO_2 capture at reduced capital and O&M cost. In addition, a number of firms are working on improved CO_2 capture systems, with most efforts in the area of enhanced or advanced amine systems. It is too early in the development process to verify or quantify the potential cost and performance benefits of these new design efforts.

Another concern is the fact that there is currently no large combustion turbine commercially available that is capable of burning the hydrogen rich gas that would result from an IGCC plant with CCS.

SCPC/USCPC

While proven carbon capture technology is available for SCPC/USCPC plants (currently limited to amine systems), there are currently no SCPC/USCPC facilities in the world that perform CCS. Depending on the carbon capture technology used, it is estimated that carbon capture and compression could add 65 - 100% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2.

A number of projects are currently underway to try to improve the capture of CO_2 from SCPC/USCPC units in terms of removal efficiency and capital and O&M expenditures. Generally, these projects are targeting 90% capture of CO_2, although there is a general belief that the optimal/achievable reduction level will be less. EPRI and Alstom are working on a chilled ammonia (chemical absorbent) system. A 5 MW slipstream chilled ammonia pilot system will go into operation in Wisconsin in the fall of 2007. According to EPRI, the goal for the project is to reduce the cost for CO2 capture and compression by approximately 66% versus the cost of conventional amine systems. While the exact costs and efficiency gains of the chilled ammonia system are not known at this time, it is known that the system efficiency will decrease in warmer climates.

Babcock & Wilcox (B&W) is currently working on a design for a 500 MW oxygen fired, recirculating gas stream (oxy-fired) boiler for Sask Power in Canada. This unit would use oxygen from an air separation unit (ASU) instead of air for combustion. This use of oxygen means that less NOx is formed (approximately 65% less) in the combustion process and that the resulting flue gas is mainly CO_2 (up to approximately 80%). The flue gas stream, after removal of particulates, SO_2 and moisture, would be recirculated through the boiler, removing a portion (20 - 35%) of the CO_2 with each pass. B&W expects to start testing the design at their 30 MW Clean Environment Development Facility (CEDF) in Alliance, Ohio in June of 2007. Net power output before CCS from the 500 MW unit is expected to be on the order of 350 MW. Additional power will be required to compress and sequester the captured CO_2.

In addition, a number of vendors are working on enhanced/advanced amine systems that they believe will outperform current amine systems.

NGCC

While carbon capture technology is available for NGCC plants (currently limited to amine systems), there are currently no NGCC facilities in the world that perform CCS. Depending on the carbon capture technology used, it is estimated that carbon capture and compression could add 40 - 80% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2.

B. Environmental: There are currently no environmental laws, rules or procedures in place for CCS projects. Issues that need to be addressed include, but are not limited to:

- How will geologic sequestration be permitted over the long-term, including demonstration studies and the duration of the sequestration permit (i.e. 5 year, life of facility, etc.)
- What measurement, monitoring and verification (MMV) techniques and requirements will be placed on the project
- How will the liability associated with the sequestered CO_2 be addressed
- How will the property rights issues associated with the sequestered CO_2 be addressed
- Will the injection of CO_2 into a deep saline aquifer prohibit the future use of water from that aquifer should in-land desalination prove to be cost-effective or necessary to address future water needs

C. Economic: The capital and O&M impacts of CCS are significant and will result in substantial increases in the cost of electricity.

IV. Background data and assumptions used:

1) Carbon Capture Research. U.S. Department of Energy
<http://www.fossil.energy.gov/programs/sequestration/capture/>
2)Carbon Capture and Sequestration Technologies, MIT.
<http://sequestration.mit.edu/>
3) Carbon Dioxide storage prized. STATOIL.
<http://www.statoil.com/statoilcom/SVG00990.NSF?OpenDatabase&artid=01A5A730136900A3412569B90069E947>
4) Carbon Sequestration. National Energy Technology Laboratory.
<http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html>

V. Any uncertainty associated with the option (Low, Medium, High)

High, as the integration of power generation and CCS is a developing and undemonstrated technology and there are currently no laws, rules and procedures are established to address CCS.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups: None at this time.

Mitigation Option: Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits

I. Description of option

Summary of Option

Agreements regarding mitigation of air quality and air quality related value impacts negotiated between PSD permit applicants and parties other than the permitting authority should be incorporated into the PSD permit and made federally enforceable. If the other party is a federal land manager, there should not have to be a formal declaration of adverse impact before the agreement is made part of the permit.

Background

A primary goal of the PSD program is to protect air quality and air quality related values in areas that attain the National Ambient Air Quality Standards, specifically certain National Parks and Wilderness areas (i.e., "Class I" areas). If representatives of a proposed new source are willing to mitigate the predicted impacts of the new facility, then the permitting authority should honor this intent to reduce air pollution impacts at Class I areas by including mitigation measures in a PSD permit.

This issue arose in the context of federal land manager (FLM) review of the Desert Rock Energy Facility permit application. Federal land managers responsible for "Class I" areas are responsible for reviewing PSD permit applications for new sources to determine if that source would cause or contribute to an adverse impact on visibility or other air quality related values. In the immediate Four Corners area, Mesa Verde National Park and Wemminuche Wilderness Area are the closest Class I areas, and would be impacted the greatest by the Desert Rock Energy Facility. However, there are a total of 15 Class I areas that could be impacted by the facility.

Typically, FLMs address potential adverse impacts through consultation with the permit applicant and permitting authority before the permit is proposed, and before any formal adverse impact finding. When it becomes apparent through the modeling analysis that a facility *may* have an adverse impact, applicants are generally willing, and actually prefer, to discuss changes to address those adverse impacts, through tightening down the control technology, obtaining emission offsets, or other methods. State permitting agencies have generally incorporated the agreed-upon mitigation measures directly into the PSD permit, which as a practical matter, makes those agreements enforceable. This process allows for consultation in the case of suspected adverse impacts and avoids delays in permitting or denial of a permit, which may result from a formal finding of adverse impact.

The permitting authority for the Desert Rock Energy Facility is the Environmental Protection Agency (EPA) Region 9, because the facility would be located on the Navajo Reservation, where neither the State of New Mexico (or Arizona) nor the Navajo Nation have permitting authority. For over two years, the National Park Service and the U.S. Forest Service worked closely with Desert Rock representatives, EPA and tribal representatives to ensure the potential impact of the proposed facility were carefully analyzed. When it became evident that emissions from the facility could adversely impact visibility in several Class I areas, the energy company suggested mitigation measures intended to produce a net environmental improvement in the area, notwithstanding construction and operation of the Desert Rocky Energy Facility. Negotiations ensued and resulted in an agreement in principle on substantive mitigation measures in April of 2006. In July, 2006, EPA issued a proposed PSD permit for the facility but did not include the agreed-upon mitigation measures. EPA reasoned that mitigation measures should not be included as part of the permit absent a formal declaration of adverse impact by the FLM.

Without the terms of the agreement in principle included as part of the PSD permit, there is no mutually acceptable way to ensure the specific mitigation measures will be enforceable, and therefore, no assurance that adverse impacts to air quality related values in Class I areas will be avoided throughout the life of the facility.

It is unacceptable that the EPA, in July 2006, issued a proposed PSD permit for the facility but did not include the agreed upon visibility mitigation measures. The so called brown curtain of "regional haze" already present which blankets the Four Corners Area blocks visibility. Not only is it ugly, it indicates degradation of the air quality. Visibility mitigation must be enforceable; therefore, visibility measures must be included in the permitting of Desert Rock and any other future coal fired power plants in the Four Corners Area.

II. Description of how to implement

The permitting authority for a given facility would be responsible for including any agreed-upon mitigation measures into a PSD permit. Usually the permitting authority is the state agency responsible for air pollution control; in some cases, however, the EPA is the permitting authority.

Regarding the actual negotiation of any mitigation measures, information regarding the mitigation measure and its effects is exchanged in the permitting process. In some instances the applicant may supply additional information in the form of an air quality modeling analysis and/or control technology analysis to demonstrate to the FLM the effectiveness of the mitigation measures in reducing impacts to AQRVs at the Class I area(s) in question.

III. Feasibility of the option

By agreeing to a mitigation measure, a permit applicant has implicitly affirmed the feasibility of the measure. Incorporation into a permit is feasible for the permitting authority as long as the measure does not contradict any statutory or regulatory provision.

IV. Background data and assumptions used

The PSD program is created at 42 U.S.C. §§7470-7492; implementing regulations are codified at 40 C.F.R. §51.166 and 40 C.F.R. §52.21.

V. Any uncertainty associated with the option

No uncertainties known.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups

None

Mitigation Option: Clean Coal Technology Public Education Program

I. Description of the mitigation option

The goal of this option is to educate all stakeholders, particularly the wider public, as to the cost/benefits of the latest clean coal technology during the permitting process for new coal based power generation facilities in the Four Corners. The public who then participates in the hearings and other steps of the permitting process, would be educated and know the pros and cons of the various technological options available to those proposing the project.

According to the Department of Energy, coal will continue indefinitely to be one of the least expensive sources of electric power in the United States. The Four Corners region has abundant coal resources and many stakeholders who wish to capitalize on that abundance to produce energy, jobs and revenue. Technologies for transforming coal to energy vary enormously in cost, and pollution, including release of global warming gases. Research into improved (cleaner) technologies continues, see President Bush's new commitment to the Clean Coal Power Initiative as one example. The public in the Four Corners area needs to be informed and frequently updated as to the status of research and testing in clean coal technology so they can ask educated questions and make educated political decisions and/or demands on policy-makers in the agencies permitting power generation installations in the Four Corners area. This mitigation option lays out a plan for the on-going education of Four Corners stakeholders with regard to the latest, cleanest, safest technologies for converting our generous resource into energy.

This option would require the primary permitting agency for a proposed project to designate early in the process a non-political 'clean coal technology scientist/advocate' whose responsibility it would be to prepare documentation in layman's terms on the latest research and feasibility of clean coal technology and where the proposed technology stands in relation to the current ideal. This individual would make presentations at hearings, be available by phone/internet for consultation with stakeholders, including the media, submit factual information pieces to the Four Corners media on clean coal technology, speak at community meetings, etc. In other words, the scientist/advocate would design and conduct an extensive public relations campaign to education the public during the permitting process.

Many institutions, including the Department of Energy, and educational institutions, conduct research in clean coal technology on an ongoing basis and NGOs like San Juan Citizens Alliance make themselves experts on the issues and could be called upon to educate the public at any given point. The obstacle here is how to ensure that the latest knowledge reaches the lay public when they can use it during the permitting process of new coal-based power plants and/or updates of older units. One way is to tie public education into the EPA permitting process. (Other ideas are welcome.) This option places an additional burden on the EPA in time, energy and cost and therefore indirectly on those proposing the new or updated power plants on to whom the additional costs of this step would be passed.

Participation of an educated public in the permitting process will lead to better long-term decision-making for the Four Corners area.

II. Description of how to implement

A. Mandatory or voluntary:
Mandatory

B. Indicate the most appropriate agency(ies) to implement:

The lead permitting agency, typically the EPA. The Department of Energy might be another appropriate agency; however, it is hard to envision how they could be motivated enough to know when and where their expertise is needed if not tied to the permitting process.

EPA is strongly encouraging companies proposing to build to power plants to meet with the local citizens in nearby communities and regional areas to discuss their plans including their projected emissions if the facility has been announced. In addition, if they are constructing near a non-attainment area for any pollutant, EPA believes it is important to meet with local air planning officials in the non-attainment area. The companies need to be willing to lay everything on the table with respect to technology, emissions, and comparisons to other similar facilities nationwide. The companies are better off actually doing these types of meetings before they even send in the permit application. Oftentimes, people are not opposed to a new cleaner EGU, but they want something done about those older existing units in the area. This hopefully will help educate the community on what the company would like to construct.

Remember once the permitting application arrives and the State proposes the permit for public comment.....some State regulatory requirements may require them to treat any meeting where comments are made about the facility's proposed permit and technology into the public record. Therefore, it would be encouraged that any meetings with the community to occur prior to the permit being public noticed.

Another option for sponsoring a Clean Coal meeting in the 4 Corners area is to invite speakers from Dept. of Energy, EPA, National Labs doing coal related work, and State permitting officials. It would also be okay to invite independent experts. Obviously, the issue becomes funding for such a meeting. Generally, a DOE and/or EPA rep will not cost you anything. Many technology vendors know the clean coal technology in depth and would participate.

Another option is to talk to state Air Quality Bureau chief about applying for special projects funds from EPA to host such an event in the future. It is not certain what type of funds DOE may have available, but they may have funding for such a meeting as well. Another option is for a company to fund as part of an enforcement settlement agreement, or for a consortium of the mining companies and power utilities to fund the meeting location, but the State to do all of the planning and agenda development for the meeting.

It would be strongly encouraged that the state environment department go through the actual permitting process at any meeting clearly showing in a process flowchart the specific points for public comment opportunities since it would be the state process that they would be following. The state environment department also needs to educate the public on the types of comments that actually are considered valid or significant comments.....(examples are great) versus the general "not in my backyard" comments.

Options for on funding, implementation, and a CCT public educational program within existing state PSD permitting programs:

- **Establish a federal/state agency MOU**: A memorandum of understanding (MOU) would provide a mechanism for CCT public information transfer during the PSD permit application. It could facilitate the selection of an independent engineer/ scientist on clean coal technology from nearby leading universities such as Colorado School of Mines or from independent national labs such as National Energy Technology Laboratory or from reputable CCT research non-for profit scientific institution such as Union of Concerned Scientists. The engineer/scientist would provide the public with status on CCT research/demonstration/commercialization as well as comparative advantages or disadvantages of these technologies with the proposed power plant technology (e.g., SCPC plant).
- **Develop and maintain a CCT education/information transfer web-portal**: New commercial power generation technological advancement occur over a relatively long time frame. An easily accessible and updatable source of CCT information and educational material can be provided through a web portal. Argonne has developed a variety of energy web portals, many with public

outreach and some with educational elements (http://ocsenergy.anl.gov/, http://www.onlakepartners.org/). A web based outreach platform can provide CCT educational material on demand in layperson language and can provide public outreach tools for more informed and effective public involvement. Advancements in the clean coal technology could be updated on a regular basis. The state permitting agency could assume web-portal maintenance with an option for independent oversight and feedback from CCT experts. These experts (an engineer/scientist) can be retained to further support these efforts in person at public meetings during breakout public CCT education sessions.

III. Feasibility of the option

A. Technical:
Feasible, these people exist in the Four Corners area; Bill Green is an example of one. The Department of Energy undoubtedly could recommend local or regional experts.

B. Environmental:
Not relevant, no impact

C. Economic:
Retaining such a scientist/advocate will cost money but the reasonable expenses for this individual could be passed by the permitting agency to the organizers of the proposed power generation facility

This may require a regulatory and fee changes by state agencies......include a requirement for such a meeting in the State rules including a fee requirement for the permit applicant to fund the meeting location/facility to host such a meeting in the Regional area of the proposed facility. It would need to be researched and discussed to ensure that it's not prohibited by the CAA.

The ideas for funding of clean coal technology education program (within existing state PSD permitting programs):

- To implement such an effective clean coal technology education program a funding mechanism needs to be worked out between states and EPA. Options include but are not limited to:
    - The permitting fee for the power plan can be increased in order to pay for the the public education outreach program (e.g., web-portal and/or CCT expert).
    - Some non-for profit foundation involved in public education can be contacted to obtain a grant to build the webportal as well as pay for the compensation to experts/scientists.
    - It may be possible to find independent experts/scientists who will be able to provide their time for free for public good but there will still be a need of compensation for travel and lodging.

D. Political:
There is likely to be political resistance to spending additional dollars in this way. Additionally, the effort to educate the public on clean coal technology should be on ongoing effort, not dependent on proposal of power plants; however, it is difficult to figure out how to tie such an independent effort to the motivation and funding that it would take to get it to actually happen.

IV. Background data and assumptions used

Assumptions:
1. Coal continues to be abundant in the Four Corners area and in demand in power generation facilities
2. Stakeholders continue to desire to construct power generation facilities in the Four Corners area using coal, as opposed to transporting it out to other areas for use.
3. A standardized cost-effective perfectly clean technology for use of coal in power generation is years away.

V. Any uncertainty associated with the option (Low, Medium, High)
The only uncertainty that exists involves the degree of success the scientist/advocate would have in educating the public given the apathy sometimes exhibited by the public around these issues

VI. Level of agreement within the work group for this mitigation option
VII. Cross-over issues to the other Task Force work groups

Mitigation Option: Utility-Scale Photovoltaic Plants

I. Description of the mitigation option

Future Large-scale photovoltaic power plants (solar energy plants) could be built to accommodate future energy demands and offset some of the current coal-based coal fired power demands

Large-scale Photovoltaic power plants would consist of many PV arrays working together. PV electricity generation does not consume fuel and produces no air or water pollution.

The Electric Power Research Institute (EPRI) announced in July 2007 the beginning of a new project to study the feasibility of concentrating solar power in New Mexico. Unlike conventional flat-plate solar or photovoltaic panels, concentrating solar power (CSP) uses reflectors to concentrate the heat and generate electricity more efficiently. There are four utility-sized CSP plants in the U.S. today; one in Nevada and three in California. Initiated by New Mexico utility PNM and with subsequent interest from other regional utilities, the project will be directed and managed by EPRI. PNM has expressed interest in building a CSP plant in New Mexico by 2010. The feasibility study for a power plant of the 50-500 megawatt (MW) size range is expected to be finished by the end of 2007. The Four Corners area is one of the best areas for solar energy production in the United States and would be an ideal location for a new solar energy plant. For example, in Farmington, NM a flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees an avg. of 6.3 hours of full sun. The solar plant could help New Mexico meet renewable energy portfolio standards. San Juan County also has a renewable energy school focusing on solar energy system design and installation. The plant could potentially be an educational/technical resource for the college.

Benefits:

- Utilities can build PV plants much more quickly than they can build conventional fossil or nuclear power plants, because PV arrays are fairly easy to install and connect
- Unlike conventional power plants, modular PV plants can be expanded incrementally as demand increases
- Utilities can build PV power plants where they're most needed in the grid, because siting PV arrays is usually much easier than siting a conventional power plant
- Solar energy is clean energy and uses the sun for fuel.

Tradeoffs:
Burdens:

- Photovoltaic systems produce power only during daylight hours, and their output thus can vary with the weather. Utility planners must therefore treat a PV power plant differently than they would treat a conventional plant.
- Using current utility accounting practices, PV-generated electricity still costs more than electricity generated by conventional plants in most places, and regulatory agencies require most utilities to supply the lowest-cost electricity

II. Description of how to implement

A. Mandatory or voluntary

Mandatory (could be added as part of Renewable Energy Portfolio system)

May become more cost effective and implemented voluntarily as the technology continues to mature and power generation stakeholders see economic advantages to solar power.

B. Indicate the most appropriate agency(ies) to implement

State and Federal Governments can pass legislation requiring larger Renewable Energy Portfolios

III. Feasibility of the option

A. Technical –
PV Technology is available and technically feasible

B. Environmental –
PV systems have little adverse environmental impact

C. Economic –
Cost of PV systems to generate power is still more expensive than conventional fossil-fuels

DOE, the Electric Power Research Institute, and several utilities have formed a joint venture called *Photovoltaics for Utility-Scale Applications* (PVUSA). This project operates three pilot test stations in different parts of the country for utility-scale PV systems. The pilot projects allow utilities to experiment with newly developing PV technologies with little financial risk.

IV. Background data and assumptions used

1. DOE Energy Efficiency and Renewable Energy, Solar Energy Technologies Program
http://www1.eere.energy.gov/solar/utility_scale.html

2. PVUSA Solar: a Renewable Ventures Project, http://www.pvusasolar.com/

V. Any uncertainty associated with the option:

VI. Level of agreement within the work group for this mitigation option: To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Biomass Power Generation

I. Description of the mitigation option

Power Generation using biomass fuels can potentially reduce net CO_2 emissions and other criteria pollutants from 4 Corners area power generation if displacing traditional coal-fired generation and is an option for future power plants in the area. Power from biomass is a proven commercial electricity generation option in the United States. With about 9,733 megawatts (MW) in 2002 of installed capacity, biomass is the single largest source of non-hydro renewable electricity. [1, 2]

Biomass used for energy purposes includes: Leftover materials from the wood products industry, Wood residues from municipalities and industry, Forest debris and thinnings, Agricultural residues, Fast-growing trees and crops, Animal manures. [2]

An aggressive Renewable Portfolio Standard was set in the 2007 NM legislative session. It includes 20% of power generation from renewables by 2020 (for large utilities) and 10% by 2020 (for rural electric cooperatives).
Biomass may be a necessary part of power generation to meet these standards.

In addition a 2005 executive order outlined Greenhouse Gas Emission Reduction Targets. These included reductions of NM Greenhouse gases to 2000 levels by 2012. Biomass power generation may be an alternative source of energy that can offset some of the CO_2 emissions from fossil fuel-based combustion.

Benefits

Biomass combustion to produce electricity generates negligible Sulfur Dioxide and it has been shown to produce less Nitrogen Oxide emissions than coal-fired combustion. CO_2 is absorbed during biomass growth cycle in photosynthesis and then released during combustion, so the direct combustion of the biomass feedstock can be considered to have a net 0 effect on CO_2 emissions. If the biomass fuel can be planted, matured, and harvested in shorter periods of time compare to the natural growth plants then the recycling of CO_2 in the environment can be reduced to close to one – third.

Other benefits include rural economic growth, increased national energy security, and using waste products that would otherwise have to be disposed. Using biomass fuel to generate electricity will reduce the greenhouse gas methane in the environment because if discarded in the landfill, the decomposition of biomass fuel generates methane.

Tradeoffs

- Land required for growing biomass.
- Higher nitrogen content of biomass fuel can contribute to higher NO_x emission such as in the case of fertilizer used to grow biomass fuel.
- N_2O emissions from fertilizer to grow biomass, if used.
- Energy emissions to grow, collect, and transport biomass fuel to plant
- Vehicle and dust emissions from transport trucks
- Energy emissions to dispose of waste
- The particulate emission from the biomass power generating power plant is a real concern. However the particulate emission can be controlled using readily available PM control technologies.

Burdens

For biomass to be economical as a fuel for electricity, the source of biomass must be located near to where it is used for power generation. This reduces transportation costs — the preferred system has transportation distances less than 100 miles.[3]

<u>II. Description of how to implement</u>

A. Mandatory or voluntary

Voluntary. Biomass may offset some of the coal based power generation.
May be necessary under new Renewable Portfolio Standard requirements for New Mexico & Colorado

B. Indicate the most appropriate agency(ies) to implement

Industry Research and Development, State and Federal Policy Support

<u>III. Feasibility of the option</u>

A. Technical – Biomass power generation is a proven commercial technology. Co-firing with fossil fuels may be the most feasible option at this time

B. Environmental – Biomass power generation has some significant advantages over fossil-fuel power generation. As demonstrated by some of the public hearings and objections to a new 35-megawatt plant, proposed to be built in Estancia, NM by Western Water and Power Production LLC., biomass may be a challenging technology to implement.

C. Economic –

A typical coal-fueled power plant produces power for about $0.023/kilowatt-hour (kWh). Cofiring inexpensive biomass fuels can reduce this cost to $0.021/kWh, while the cost of generation would be increased if biomass fuels were obtained at prices at or above the power plant's coal prices. In today's direct-fired biomass power plants, generation costs are about $0.09/kWh. In the future, advanced technologies such as gasification-based systems could generate power for as little as $0.05/kWh. For comparison, a new combined-cycle power plant using natural gas can generate electricity for about $0.04-$0.05/kWh at fall 2000 gas prices.[3]

<u>IV. Background data and assumptions used</u>

1. US DOE Energy Efficiency and Renewable Energy, Biomass Program
http://www1.eere.energy.gov/biomass/technologies.html

2. EIA RENEWABLE ENERGY 2002,
http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/table5.html]

3. US DOE Energy Efficiency and Renewable Energy, State Energy Alternatives
http://www.eere.energy.gov/states/alternatives/biomass.cfm

4. Electricity From: Biomass
http://powerscorecard.org/tech_detail.cfm?resource_id=1

<u>V. Any uncertainty associated with the option</u>: High.

VI. Level of agreement within the work group for this mitigation option: To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Bioenergy Center

I. Description of the mitigation option

Sunflower Electric Power Cooperative is planning a bio-energy center adjacent to their coal fired electric plant in rural Kansas[1].Three new 700 MW units are planned to supplement the existing 360 MW unit. The bioenergy center promises some CO2 mitigation along with energy efficient and low pollution auxiliary business enterprises. The bioenergy center concept involves a feedlot, dairy, anaerobic digester, algae reactor, ethanol plant, biodiesel plant, and the coal plant. Methane, electricity, ethanol, and biodiesel will be produced. The wastes (water, manure, biogas, nitrogen, phosphorus, flue gas, glycerol, CO2, wet distiller's grain, and ammonia) are used for inputs for the processes, rather than being discarded.

The anaerobic digester processes manure to produce methane to power the ethanol plant. The algae reactor consumes CO2 from the coal plant flue gas, and nitrogen and phosphorus from the anaerobic digester. The reactor then produces oil-rich protein for biodiesel production, with the residue used for livestock feed. The ethanol plant will consume corn and grain sorghum, and produce wet-distillers grain for livestock feed.

Locally, there could be variations on this theme. Excess corn fodder biomass, not fed to livestock, could be burned in the power plant. Only the grain is useful in ethanol production with current technology. Livestock could be omitted and the ethanol plant powered with natural gas.

Benefits: Any burned biomass has close to zero net effect on CO2 emissions from the coal fired power plant. Energy efficient businesses produce ethanol and biodiesel for sale. Local economic growth is enhanced, with increased national energy independence. Waste products are recycled that would otherwise have to be disposed.

Tradeoffs:
Land is needed to grow grain crops
Nitrate run-off from needed fertilizer
Ancillary energy usage, and lowering of CO2 net efficiency, to cultivate, harvest, and transport the crop, and remove waste products

II. Description of how to implement

A. Mandatory or voluntary: Voluntary.
It should be more feasible to plan such an adjunct facility at the proposed Desert Rock Power Plant, rather than at the existing power plants. Livestock and grain crops could be expanded at the NAPI, resulting in short transportation distances. Sithe Global is required to provide financing for local environmentally beneficial projects as an offset for tax benefits. This could help fund the feasibility studies for this project and a portion of the construction costs.

B. Indicate the most appropriate agency(ies) to implement
Navajo Nation, San Juan County, State of New Mexico economic development departments

III. Feasibility of the option

A. Technical – Co-firing biomass in coal plants is proven technology. Ethanol plants are being constructed at a rapid pace. There is a local construction company with extensive experience with ethanol plants. Each bio-energy component has been commercialized to some degree, but the challenge is the integration of these components in an energy center.

B. Environmental – VOC emission output from an ethanol plant could be mitigated by vapor capture routed to the power plant, or to a thermal oxidizer. The thermal oxidizer could accommodate vapors from the biodiesel plant. A portion of the power plant and thermal oxidizer CO_2 emissions would be mitigated by the algae reactor. Expanded feedlot activities have associated groundwater, ozone layer (methane), and odor impacts.

C. Economic – Detailed economic modeling is needed along with the engineering studies to provide input to a viable business plan. A renewable energy project should attract grant money and gain tax benefits. Labor infrastructure at the Desert Rock construction site could be leveraged to construct, then operate the bio-center.

<u>IV. Background data and assumptions used</u>

1. "Farming for Energy" Sunflower Electric's Bioenergy Center in Kansas – EnergyBiz Magazine, Jan./Feb. 2007 -- www.energycentral.com

2. Kansas Technology Enterprise Corporation --   http://www.ktec.com/index_Flash.htm

3. Four Corners Air Quality Task Force Mitigation Option "Biomass Power Generation"

<u>V. Any uncertainty associated with the option (Low, Medium, High)</u> High
<u>VI. Level of agreement within the work group for this mitigation option</u> To be discussed.
<u>VII. Cross-over issues to the other Task Force work groups</u>
Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Nuclear Option

I. Description of the mitigation option

Nuclear reactor power generation should be considered as a mitigation option. We should not assume that it is too politically controversial for consideration. The mitigation options would lack balance if the taskforce were not to consider a future nuclear power plant. Such a plant would have virtually zero air emissions and global warming impact.

The U.S. Nuclear Regulatory Commission is adding staff to consider up to 30 nuclear units in fiscal 2008. This was motivated by the Energy Policy Act of 2005, which has invigorated the power industry to come forward with new plans. A new NRC office has been created solely for licensing and oversight of new reactor activities, with a current staff of 240. Many of these units will be in the south and southeast, where utilities have prior nuclear experience. NRC has streamlined their processes so standard design certifications will be approved, and the safety design hurdle will not be raised continually. Many of these applications will be active pump/valve cooling designs that meet the stringent safety requirements of standard design certifications.

These designs include the GE AWBR (Advanced Boiler Water Reactor), the Areva EPR (Evolutionary Power Reactor), and the Mitsubishi advanced pressurized water reactor. Bechtel is working on standard, pre-engineered modular designs, so that units can be replicated quickly and cost effectively. Construction time is approximately four to five years. If fifteen units were to be built from now until 2020, there would be a need for 30,000 new high-paying craft jobs. Several utilities are committing to these designs because of the certainty they will be completed on schedule with low risk financing, and their operating experience at similar plants.

There is promise for a family of passive cooling reactors, where gravity/density differences provide equivalent convection cooling protection to electrically powered valves and pumps. These designs would be simpler and less expensive than current active pump designs. Much design work has been done, although there is not currently such a unit in operation. General Electric is offering its ESBWR (Economically Simplified Boiling Water Reactor) and Westinghouse its AP1000, an advanced passive reactor. TVA and Entergy are considering use of this technology. Plants of this type will be among those soon licensed by the NRC.

Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s.

Opposition will come from perceived plant safety and spent fuel issues. Regional storage of spent fuel already exists in New Mexico. It is likely that Yucca Mountain will be licensed for long term storage. New Mexico should participate in research for the safe long term storage of spent nuclear fuel. There is strong congressional and public recognition that nuclear power generation should be part of the energy portfolio, along with increased renewables, to address climate change. There is also a 20-30% group that opposes both existing and future nuclear power generation. This level of opposition would also be expected in New Mexico, and must be considered in any political process to license a nuclear plant locally. Worldwide, especially in China and India, there is a very active nuclear buildout in progress. Nuclear power generation is actively expanding worldwide, and about to in the United States.

A realistic approach would keep our options open politically, while closely monitoring the re-emergence of the nuclear industry in the United States over the next 5 – 10 years. We should especially follow the operating experience of the new passive cooling reactors which should be on-line in less than ten years.

New Mexico is already in an area of low seismic activity. The additional safety advantage of a passive reactor design should lower public opposition significantly. Much of the anticipated surge of nuclear construction is by existing utilities that already operate conventional nuclear plants. It makes economic sense for many of them to continue in this direction. That argument does not hold in New Mexico, and we should embrace the construction of one or more passive nuclear power reactors as this technology matures.

We would expand our use of local coal reserves with the new Desert Rock power plant, and enjoy very low air emissions from that plant, except for the increased carbon footprint. Longer term (10 – 20 years), as power needs increase, we should consider a passive reactor nuclear plant instead of another coal fired plant. Some existing local coal fired units may approach the end of their design life and be retired. That retired power could be replaced by nuclear generation, with zero air emissions and carbon footprint.

A nuclear building program in the Four Corners would greatly enhance the growth of a local and regional high technology professional and vocational workforce. San Juan College would step up with new programs to educate the vocational workforce needed to build and operate a nuclear plant. The college should also benefit from creative financing support similar to that proposed for Desert Rock. The Four Corners and New Mexico would be recognized as an energy focal point in the U.S., with an exceptional balance of conventional, renewable, and nuclear energy generation, along with our strong base in oil/gas production.

Benefits: Zero air emissions impact; No carbon footprint; Cost effective electricity generation; Foster high technology educational and employment basis in the Four Corners; Proximity to current New Mexico and future Nevada spent fuel storage site.

Tradeoffs: Minority negative public opinion related to plant safety and spent fuel containment.

Differing Opinion: While it may be true that nuclear power plants have almost no carbon dioxide emissions (except in construction and in mining, processing and supplying the uranium fuel) and low global warming impact, there are other enormous liabilities which make them, in my opinion, the least desirable alternative to replace fossil fuel-fired power plants.

The availability of fissionable uranium (U-235) is not discussed. The supply will be quite limited, especially if the rate of usage increases significantly. One proposed solution, going to breeder reactor technology, would involve transport of radioactive materials to and from reprocessing plants, entailing enormous problems of safety and security.

The stated maintenance cost of 1.7 cents per Kwh for nuclear plants is deceptive. In all likelihood it does not include the cost of decommissioning the facility at the end of its useful life, nor the totally unknown cost of eventual "permanent" storage of the radioactive waste products. It also does not include any portion of the massive and continuing federal subsidies for nuclear R&D ($145 billion between 1947 and 1998 according to one source).

The issue of permanent storage of radioactive wastes (spent fuel) is not adequately discussed. The federal government and the nuclear industry have had half a century to develop permanent storage facilities; it seems they are no closer to a solution than when they started. Yucca Mountain is not close to viable, the latest blow being a federal court decision upholding the Nevada State Water Engineer's authority to deny the federal government's use of groundwater at the site. Even if a permanent storage facility is eventually developed, there is a major moral issue. I do not believe we have the right to impose an almost perpetual guardianship role on future generations (8,000 generations if the estimate of a 200,000 year storage time for plutonium wastes is accurate).

II. Description of how to implement
A. Mandatory or voluntary
B. Indicate the most appropriate agency(ies) to implement

III. Feasibility of the option
A. Technical –
B. Environmental –
We would expand our use of local coal reserves with the new Desert Rock power plant, and enjoy very low air emissions from that plant, except for the increased carbon footprint. Longer term (10 – 20 years), as power needs increase, we should consider a passive reactor nuclear plant instead of another coal fired plant. Some existing local coal fired units may approach the end of their design life and be retired. That retired power could be replaced by nuclear generation, with zero air emissions and carbon footprint.
C. Economic –
Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s.

IV. Background data and assumptions used:
Reference: Energybiz magazine Vol. 4, Issue 3 (May 07, June 07) "Agency Gets Ready for Nuclear Renaissance" -- "Repackaging the Nuclear Option" -- "GE Gears Up." Vol. 4, Issue 4 (July 07, August 07) “Bechtel sees Nuclear Surge” and “The Nuclear Balance Sheet.”

V. Any uncertainty associated with the option: TBD
VI. Level of agreement within the work group for this mitigation option: To Be Determined.
VII. Cross-over issues to the other Task Force work groups:
Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

OVERARCHING: POLICY

Mitigation Option: Reorganization of EPA Regions

I. Description of the mitigation option

The Four Corners geographic area is under the jurisdiction of three different regions of the Environmental Protection Agency: Colorado and Utah are in Region 8, headquartered in Denver; New Mexico is in Region 6, headquartered in Dallas; and Arizona (and the Navajo Nation, which is in both Arizona and New Mexico) is in Region 9, headquartered in San Francisco.

Due to the abundance of coal and oil and gas in the San Juan Basin energy development in the area is likely to continue. It is becoming increasingly well-documented that the majority of the pollution experienced in the Four Corners area is coming from coal-fired power plants on or near reservation lands in New Mexico as well as oil and gas development throughout the region. The EPA staff engaged in addressing environmental impacts from oil and gas development, and responsible for actually permitting or overseeing permitting of stationary sources (power plants) needs to be located where the pollution is happening and be responsible to the recipients of that pollution as well as to hold its generators accountable.

A permanent EPA human presence within the area of energy development and pollution would sensitize EPA personnel to the issues within the Four Corners area. Creating an interregional office of the EPA with jurisdictional authority in order to include within a single jurisdiction the pollution generating sources and the public lands and communities they impact would improve EPA effectiveness in oversight and permit processing by facilitating communication and focusing feedback.

II. Description of how to implement

Create a permanent inter-region office within the EPA chartered to focus on, and located in, the Four Corners region. The office would assume all regional duties with respect to the Four Corners area, and have responsibility for overseeing state and tribal permitting, permitting stationary sources in the absence of state or tribal permitting, and any activities relating to oil and gas development currently performed by the various regions.

III. Feasibility of the Option

EPA Headquarters, as well as the three regions involved, would need to approve this option. The states and tribes would need to support this option as well.

IV. Background data and assumptions

The statement by Colleen McKaughan of Region 9 to the Durango Herald epitomizes our perception of the sensitivity of Region 9 personnel to the issues in the Four Corners region. As quoted in the Durango Herald on September 15, 2006, Ms. McKaughan, an air-quality expert with the federal Environmental Protection Agency's Region 9, said the Four Corners region has air so clean that it can absorb additional pollutants without harm. She said the EPA had no significant concerns about the proposed coal-fired Desert Rock plant.

V. Any uncertainty associated with the option There is a high level of uncertainty in getting something like this passed politically and how long it would take is an unknown.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues Oil and Gas Work Group, Other Sources Work Group.

OVERARCHING: MERCURY

Mitigation Option: Clean Air Mercury Rule Implementations in Four Corners Area

I. <u>Description of the mitigation option</u>
States and tribes are presently drafting regulations (some such as NM and CO now have completed rules, see appendix on NM & CO) to meet the Clean Air Mercury Rule (CAMR) while simultaneously meeting their mission to protect public health and the environment. For states, this means allocating mercury allowances to electric generating facilities to operate. CAMR may eventually have profound effects on the amount of mercury reduced from the affected facilities.

States participating in the Task Force might work in concert to determine if even greater reductions are possible than initially scheduled in CAMR. Some examples of working in concert might include:

- “Incentivizing” early mercury reductions at CAMR-affected facilities;
- Retiring any excess allowances that may exist (Colorado has in effect a “Colorado Citizens’ Trust” to effectively permanently set aside excess allowances);
- Addressing the concerns for local mercury impacts (“hot spots”) from new and proposed facilities in the Four Corners area by requesting that State air quality permitting agencies consider this hot spot criterion in their decision to approve/disapprove facilities’ air quality permit requests (as individual state budgets and their “set aside allowances” may be inappropriate indicators of the impacts the local area might receive from power plants in Four Corners);
- Promoting additional mercury studies (e.g., air deposition) that would benefit Four Corners area (could/should be tied to option #5);
- Requiring early installation of mercury CEMs at facilities (to better gauge effectiveness of various co-control efforts);
    - For example, Mercury CEMs will be installed on 2 of the 4 units at San Juan by 12/31/07 and the other 2 units by 12/31/08.
- Developing more stringent control requirements for facilities in Four Corners Area;
- Other examples as identified.

II. <u>Description of how to implement</u>
<u>A. Mandatory or voluntary:</u>
Could be either mandatory or voluntary depending on the specifics of the option.

Differing Opinion: Since many of Four Corners Area lakes, streams, and rivers are currently under a mercury advisory, mandatory control of mercury is necessary. The health of humans and other living beings is at risk

<u>B. Indicate the most appropriate agency(ies) to implement:</u>
States’ environmental (permitting) agencies

<u>III. Feasibility of the option</u>
<u>A. Technical:</u> Some of the technical options may be difficult to implement, especially depending on the timing. That is, CAMR plans are due to EPA by November 2006 and hence options developed here may come too late. However, options developed here could be possibly used in the states’ future allocation schemes and/ or approaches surrounding CAMR.
<u>B. Environmental:</u> N/A
<u>C. Economic:</u> Difficult to ascertain as this depends on the specifics of the option developed.

IV. Background data and assumptions used

CAMR information and data are plentiful; however, the long-term application and effectiveness of various strategies to reduce mercury from power plants is difficult to predict.

Basic Information on New Mexico CAMR:

- Rule applicability covers coal-fired EGUs (presently 4 units at San Juan Generating Station and 1 unit at Escalante Generating Station).
- Mandatory mercury monitoring by sources begins 1/1/09.
- Mercury limitations become effective 1/1/10.
- See Tables 1 and 2, below, for mercury emissions data and proposed limitations.
- Monitoring includes installing monitoring systems (CEMS or sorbent traps), certification, performance test, and recording, quality-assuring, and reporting data.
- Initial monitoring performance test is 12 months (calendar year 2009).
- State rules takes state "budget" and turns it into state "cap" with portions of the cap assigned to facilities as facility-wide emission limitations as well as EPA-recommended new source set-aside.
- State rules prohibit participation in trading and banking program.
- State rules establish emissions fees to support one full-time equivalent for implementation of the mercury rules.

Table 1: New Mexico Mercury Emissions Data	
New Mexico Mercury Emissions (1999 EPA data; Tons)	1.09
New Mexico Mercury Emissions (2004 TRI data; SJGS + Escalante; Tons)	0.389
New Mexico Mercury Budget (2010-2017; Tons per year)	0.299
New Mexico Mercury Budget (2018 and after; Tons per year)	0.118

Table 2: New Mexico Mercury Limitations (Per year)						
	2010-2017			**2018 and after**		
	Tons	Ounces	%	Tons	Ounces	%
Total "State Cap"	0.299	9,568	100 %	0.118	3,776	100 %
San Juan Generating Station	0.244	7,808	81.6 %	0.104	3,323	88 %
Escalante Generating Station	0.04	1,280	13.4 %	0.01	340	9 %
New Source Set-Aside	0.015	480	5 %	0.035	113	3 %

Basic Information on Colorado CAMR:

Overview: Colorado's Air Quality Control Commission adopted a rule specific to CO's Utility Hg Reduction Program on 2/6/07. This rule specifies 100% of the state's allowances be transferred into the State's General Account. The State allocates allowances to units based on annual actual emissions, up to Model Rule allocations with an option to access additional allowances based on need through a safety-valve. In addition, the rule requires phased reductions over time on a rolling 12-month average basis, exempting low mass emitters and new units with existing permits in place:

• 2012: Pawnee and Rawhide 0.0174 lb/GWh or 80% inlet Hg capture;
• 2014: 0.0174 lb/GWh or 80% inlet Hg capture; and
• 2018: 0.0087 lb/GWh or 90% inlet Hg capture.

This rule allows for averaging of units at the same plant. The rule also provides soft-landing, requiring Best Available Mercury Control Technology installation if units demonstrate to the State that they cannot meet the performance standard. Finally, the rule includes a provision associated with retirement of allowance accrual, beginning in 2016, 2019 and every five years thereafter, if no separate rulemaking is commenced prior.

Trading: Yes, but allocations are made based on actual emissions.

Allowance Allocations: Up to 95% in phase I and 97% in phase II, with the remainder used for new units. However, actual allocations are made based on actual emissions, which are reduced over time due to state-only Hg emission standards. Therefore allocation amounts are also expected to decrease over time.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium – again, the long term application and effectiveness of various strategies to reduce mercury from power plants is difficult to predict.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other Task Force work groups

TBD.

Mitigation Option: Federal Clean Air Mercury Rule (CAMR) Implementation on the Navajo Nation

I. Description of the mitigation option

The Environmental Protection Agency (EPA) promulgated the Clean Air Mercury Rule (CAMR) on May 18, 2005. CAMR established a mechanism by which mercury (Hg) emissions from new and existing coal-fired power plants (EGUs) are capped at nation-wide levels of 38 tons/year effective in 2010 and 15 tons/year effective in 2018. EPA then established Hg emission levels for each state and for Indian country in cases where there are existing EGUs; this includes the Navajo Nation. State and Tribal plans to implement and enforce Hg emission levels were to be submitted to EPA by November 17, 2006. State plans can be more stringent than the EPA Model Rule and may or may not allow trading or banking of emissions allowances.

In cases where a State or Indian Tribe does not have an approvable plan in place by the prescribed deadline of March 17, 2007, EPA may implement a Federal plan by May 17, 2007. In order to facilitate this action, EPA published proposed rules on December 22, 2006. These rules are expected to be finalized by May 17, 2007, and will be used to implement CAMR on the Navajo Nation. A major shortcoming of these EPA rules is the lack of provision for meaningful public participation in the process to develop and allocate specific Hg emission limits for existing and proposed EGUs on Navajo Nation lands. This is significant since the Navajo Nation mercury emissions budget is larger than that of either Arizona, New Mexico, or Utah, and almost as large as the budget for Colorado.

The Navajo EPA, Region 9 EPA, and the operating agencies for the Four Corners Power Plant and the Navajo Generating Station – Arizona Public Service Company (APS) and the Salt River Project Agricultural Improvement and Power District (SRP), respectively – have already had discussions regarding a potential allocation methodology for the Navajo Nation. A meeting was held on July 10, 2006, at which Region 9 EPA presented a "strawman" proposal which differed significantly from the EPA model Rule with respect to the amount and disposition of the new source set-aside portion. This proposal has not been well-received by APS and SRP. The degree to which the air quality agencies in the surrounding, contiguous, and sometimes overlapping States of Arizona, Colorado, New Mexico and Utah have been aware of these early meetings is not known. From all appearances it seems that much greater effort should go towards facilitating adequate public participation in this process. The prime responsibility for achieving this rests with Region 9 EPA.

At a minimum the process for allocation of mercury emissions limits to EGUs in Navajo lands should be at least as open to public participation as the most transparent State CAMR process has been. For the Navajo Nation this might include informational meetings and public hearings in Window Rock and Page, Arizona, and Farmington, New Mexico. Final decisions on nature and location of meetings should be negotiated among the various jurisdictional agencies.

II. Description of how to implement

A. Mandatory or voluntary

This should be mandatory. In the past, public participation has been a cornerstone of EPA policy and in fact is mandated in many of their regulations.

B. Indicate the most appropriate agencies to implement

Region 9 EPA, with assistance and cooperation of Navajo EPA and air quality agencies in affected States.

III. Feasibility of the option

A. Technical: Entirely feasible

B. Environmental: Feasible

Economic: Feasible; minor administrative costs to conduct public meetings and hearings
Political: Medium feasibility. Some advocacy to Region 9 EPA may be needed to implement this option.

IV. Background data and assumptions used

A small amount of information has been received from Region 9 EPA.
Clean Air Mercury Rule making process is in process so newer information may now be available

V. Any uncertainty associated with the option

Medium – responsibility to implement rests primarily with Region 9 EPA.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups TBD

OVERARCHING: AIR DEPOSITION STUDIES

Mitigation Option: Participate in and Support Mercury Studies

I. Description of the mitigation option

Background

Rationale and Benefits: Methyl mercury is a known neurotoxin affecting humans and wildlife. Coal-fired power plants are the number one source of mercury emissions in the United States[1]. The Four Corners already is home to several power plants that are large emitters of mercury and additional coal-powered plants are proposed for the region. Individuals and community groups in the San Juan Mountains have expressed great concern about mercury emissions in our region and the existing mercury fish consumption advisories in several reservoirs. Studies of mercury in air deposition, the environment and in sensitive human populations (such as pregnant women) are necessary to set a baseline for current levels and to detect future impacts of increased mercury emissions on these sensitive human populations and natural resources, including the Weminuche Wilderness, a Federal Class I Area.

Existing mercury data for the Four Corners region: Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network (MDN)[2]. Results show mercury concentrations among the highest in the nation. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS[3] and moderate concentrations similar to the Colorado Front Range have been recorded. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for McPhee, Narraguinnep, Navajo, Sanchez and Vallecito Reservoirs [4]. Sediment core analysis for Narraguinnep Reservoir show that mercury fluxes increased by approximately a factor of two after about 1970[5]. Finally, atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these waterbodies, respectively[6].

Data Gaps: Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. Mercury amounts and concentrations in wet deposition at Mesa Verde National Park are not likely to portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of waterbodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

Three new studies have begun or will begin in 2007, however. In 2007, the Mountain Studies Institute (MSI) will measure total mercury in bulk atmospheric deposition (collector near NADP station at Molas Pass), in lake zooplankton (invertebrates eaten by fish), and in lake sediment cores in the San Juan Mountains, a project funded by the U.S. EPA and USFS[8]. Dr. Richard Grossman is measuring mercury levels in hair collected from pregnant women in the Durango vicinity. Lastly, the Pine River Watershed Group (via the San Juan RC&D) recently was granted start-up funds to initiate event-based sampling of mercury in atmospheric deposition at Vallecito Reservoir and accompanying back-trajectory analyses to locate the source of these storm events.

Option 1: Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

Option 2: Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

Option 3: Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., recommendations 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgibin/asap.cgi/esthag/asap/html/es060377q.html[9]). This study would build on the pilot study planned for Vallecito Reservoir. Costs TBD.

Option 4: Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

Option 5: Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

Option 6: Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

II. Description of how to implement

See above. Studies would utilize the existing Mercury Deposition Network and expertise developed from past and ongoing studies. Investigators could include scientists from academia, non-profit, private and government organizations and agencies.

III. Feasibility of the Option

Technical -Very feasible; all technology exists or is in development for the above options.

Environmental – Very feasible. Harmful effects on the environment are negligible and permits for sample collection should be easy to obtain.

Financial – Uncertain. It is likely that a consortium of funding entities collaborate for these options. Potential partners include States, industry, US-EPA, USDA-Forest Service, US-Department of Energy, and local governments, watershed groups and public health organizations.

IV. Background data and assumptions used See introduction section

V. Any uncertainty associated with the option Funding uncertainty.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups Energy and Monitoring Groups

Citations:

[1] See http://www.epa.gov/mercury/about.htm.
[2] National Atmospheric Deposition Program (NADP). Mercury Deposition Network http://nadp.sws.uiuc.edu/mdn/. National Trends Network. http://nadp.sws.uiuc.edu/.
[3] Campbell, D, G Ingersoll, A Mast and 7 Others. Atmospheric deposition and fate of mercury in high-altitude watersheds in western North America. Presentation at the Western Mercury Workshop. Denver, CO. April 21, 2003.
[4] Colorado Department of Public Health and Environment website: http://www.cdphe.state.co.us/wq/FishCon/FishCon.htm and http://www.cdphe.state.co.us/wq/monitoring/monitoring.html.
[5] Gray, JE, DL Fey, CW Holmes, BK Lasorsa. 2005. Historical deposition and fluxes of mercury in Narraquinnep Reservoir, southwestern Colorado, USA. Applied Geochemistry 20: 207-220.
[6] Colorado Department of Public Health (CDPHE). 2003. Total Maximum Daily Load for Mercury in McPhee and Narraguinnep Reservoirs, Colorado: Phase I. Water Quality Control Division. Denver, CO. http://www.epa.gov/waters/tmdldocs/Mcphee-NarraguinnepTMDLfinaldec.pdf.
[7] Schindler, D. 1999. From acid rain to toxic snow. Ambio 28: 350-355
[8] See http://www.mountainstudies.org/Research/airQuality.htm.
[9] See http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html

OVERARCHING: GREENHOUSE GAS MITIGATION

Mitigation Option: CO_2 Capture and Storage Plan Development by Four Corners Area Power Plants

<u>I. Description of the mitigation option</u>

Carbon sequestration refers to the provision of long-term storage of carbon in the terrestrial biosphere, underground, or the oceans so that the buildup of carbon dioxide (the principal greenhouse gas) concentration in the atmosphere will reduce or slow. In some cases, this is accomplished by maintaining or enhancing natural processes; in other cases, novel techniques are developed to dispose of carbon.

Emissions of CO_2 from human activity have increased from an insignificant level two centuries ago to over twenty five billion tons worldwide today (1). The additional CO_2, a major contributor to Greenhouse gases, contribute to the phenomenon of global warming and could cause unwelcome shifts in regional climates (1).

The contribution of CO_2 from the 2 major power plants in the 4Corners area is approximately 29,000,000 Tons of CO_2 per year. The proposed Desert Rock Energy Project would add an approximate additional 11,000,000 Tons of CO_2 per year.

Facilities in the Four Corners area should begin developing carbon sequestration plans to mitigate this important global issue. Four Corners area power plants should research & develop way to reduce their CO_2 emissions.

<u>Benefits:</u> CO_2 emissions reductions would reduce the Greenhouse Gases output of the 4Corners area. Carbon sequestration would slow the buildup of CO_2 emissions in the atmosphere. It would be a regional action to reducing the trends of global warming. Benefits would be environmental and economic. CO_2 capture and injection may have a beneficial use for enhanced oil recovery in the 4C area

<u>Tradeoffs:</u> no tradeoffs

<u>Burdens:</u>
The benefits of protecting the climate will be realized globally and far in the future; the cost of each GHG emissions reduction project is local and immediate.

Cost to power plants, administrative costs.

Sequestration, isolating the CO_2 emissions is cheap; however, capturing/storing is expensive.

<u>II. Description of how to implement</u>

<u>A. Mandatory or voluntary</u>
Combination of mandatory and voluntary
Voluntary: 4C area power plants should begin developing Carbon Sequestration Plans
Mandatory limits or allocations may be set by State and Federal regulators in the near future.

<u>B. Indicate the most appropriate agency(ies) to implement</u>
State and Federal Regulators can allocate Carbon budgets which will lead to more controls
Appropriate State/Federal agencies to help assess Carbon potential storage areas as part of planning process

III. Feasibility of the option

A. Technical: Technologies exist; many are in R&D phase.
B. Environmental: Capturing and storing CO_2 emissions is difficult.
C. Economic: Capturing CO_2 emissions is expensive.
D. Legal: Liability of CO_2 storage process

IV. Background data and assumptions used

1. Carbon Sequestration Technology Roadmap and Program Plan 2006, US DOE
2. CO2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10)
3. San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as an estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
4. US DOE Carbon Sequestration Regional Partnerships:
http://www.fossil.energy.gov/programs/sequestration/index.html
New Mexico Partnerships
http://www.fossil.energy.gov/programs/projectdatabase/stateprofiles/2004/New_Mexico.html

V. Any uncertainty associated with the option

Medium.

VI. Level of agreement within the work group for this mitigation option.

To Be Determined.

VII. Cross-over issues to the other Task Force work groups

CO_2 emissions reduction Cross-over issue with other energy industries such as Oil & Gas. Oil & Gas industries could also be held responsible for developing Carbon sequestration plans.

CO_2 capture and injection may have a beneficial use for enhanced oil recovery in the Four Corners area.

Mitigation Option: Climate Change Advisory Group (CCAG) Energy Supply Technical Work Group Policy Option Implementation in Four Corners Area

I. Description of the mitigation option

The New Mexico Climate Change Advisory Group (CCAG) is a diverse group of stakeholders from across New Mexico. At the end of 2006, the group will put forth policy options for reducing greenhouse gas emissions in NM to 2000 levels by the year 2012, 10% below 2000 levels by 2020 and 75% below 2000 levels by 2050. 69 recommendations covering transportation, land use, energy supply, agriculture and forestry were made which if implemented would exceed emissions reduction target for 2020.

A GHG emissions inventory for New Mexico prepared by The Center for Climate Strategies (2) showed electricity generation to comprise 40% of the states GHG emissions. The electricity generation sector is a source contributor of GHG and there are many areas for potential reductions. In the future, if the proposed Desert Rock Energy Project comes online, the additional 11 million tons of CO2 from Desert Rock would increase the electricity generation portion of New Mexico GHG emissions to approximately 50%.

The energy supply technical work group drafted options for renewable portfolio standards and advanced coal technologies (1). These policy options should be applied to Four Corners area facilities. The contribution of CO_2 from the 2 major power plants in the 4Corners area is approximately 29,000,000 Tons of CO_2 per year. The proposed Desert Rock Energy Project would add an additional estimated 11,000,000 Tons of CO_2 per year (3).

Local State/Federal Regulating agencies should work with the existing and proposed power plants to collaborate to help realize the targets of the Climate Change Advisory Group. CO_2 sequestration technologies and other Greenhouse gas mitigation strategies should be assessed and implemented to meet the targets.

Benefits:
Environmental: reduction of greenhouse gas emissions to 2000 levels by the year 2012, 10% below 2000 levels by 2020 and 75% below 2000 levels by 2050. Mitigation of adverse climate change effects

Net economic savings for the state's economy

Tradeoffs: none
Burdens: Cost to existing and proposed power pants and administrators

II. Description of how to implement

A. Mandatory or voluntary
Combination of mandatory and voluntary

B. Indicate the most appropriate agency(ies) to implement
State and Federal Regulators:
Oil Conservation Division (NMOCD)
New Mexico Air Quality Bureau
New Mexico Energy, Minerals, and Natural Resources Division

Other Four Corner State Environmental Protection Agencies

III. Feasibility of the option

A. Technical: TBD

B. Environmental: TBD
C. Economic: TBD

IV. Background data and assumptions used
(1) New Mexico Climate Change Advisory Group (CCAG): http://www.nmclimatechange.us/
(2) Draft New Mexico Greenhouse Gas Inventory and Reference Case Projections, The Center for Climate Strategies, July 2005
(3) CO_2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
(4) San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as an estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
(5) Carbon Sequestration Technology Roadmap and Program Plan 2006, US DOE

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option
To Be Determined.

VII. Cross-over issues to the other Task Force work groups
Greenhouse Gas (GHG) emissions reduction Cross-over issue with other energy industries such as Oil & Gas.

OVERARCHING: CAP AND TRADE

Mitigation Option: Declining Cap and Trade Program for NO_x Emissions for Existing and Proposed Power Plants

I. Description of the mitigation option

Cap and trade is a policy approach to controlling large amounts of emissions from a group of sources at costs that are lower than if sources were regulated individually. The approach first sets an overall cap, or maximum amount of emissions per compliance period, that will achieve the desired environmental effects. Authorizations to emit in the form of emission allowances are then allocated to affected sources, and the total number of allowances cannot exceed the cap.

Individual control requirements are not specified for sources. The only requirements are that sources completely and accurately measure and report all emissions and then turn in the same number of allowances as emissions at the end of the compliance period.

For example, in the Acid Rain Program, sulfur dioxide (SO_2) emissions were 17.5 million tons in 1980 from electric utilities in the U.S. Beginning in 1995, annual caps were set that decline to a level of 8.95 million allowances by the year 2010 (one allowance permits a source to emit one ton of SO_2). At the end of each year, EPA reduces the allowances held by each source by the amount of that source's emissions (1, EPA Clean Air Markets).

A declining cap and trade program means that the cap would be slightly lowered over time to reduce the total NOx emissions in the Four Corners area. A declining cap and trade program would be effective for the Four Corner areas' electric generating units.

The power plants in the area have continuous emissions monitors. We can measure accurately each plant's NOx emissions. In 2005 the NO_x emissions from San Juan Generating Station were 27,000 tons. The Four Corners Power Plant emitted 42,000 tons (2). Desert Rock Energy facility would add an approximate 3,500 tons/yr (2). NO_x emissions from electricity generating units (EGUs) will continue to be reported and recorded under the EPA Acid Rain Program (3). So the data is available. For each of these facilities the costs for additional controls and NO_x emissions reductions is different.

Electric Generating Units (EGUs) will be defined as it is EPA's Clean Air Interstate Rule:

(a) Except as provided in paragraph (b) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil fuel fired combustion turbine serving at any time, since the start-up of a unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

The program will cover all EGUs.

The Four Corners area declining cap and trade program would cap NO_x levels from EGUs at current levels. The cap could be lowered 5% every 10 years or a collaboratively agreed on level.

The Declining cap and trade program would include all EGUs in the Four Corners area, and could also possible be extended to oil & gas sources. New sources could obtain offsets.

There should be some discussion regarding how the cap would be set; as well as how to protect against hot spots.

Benefits: The cap will prevent NO_x emissions from the Four Corners area sources from increasing. Regardless of new power plants, sources will have to find a way to keep overall NO_x emissions below the declining cap.

The program will reduce NO_x emissions in the Four Corners area.
Power Plants would continue to look at new ways to reduce emissions.

Differing Opinion: Cap and trade is a band aid approach to reduction of emissions. It may look good on paper, but does nothing to enhance the air quality. Cap and trade should not be an option for power plant or oil and gas emissions in the Four Corners Area. Extensive improvement of the air quality and consideration for the health and welfare of the people and the environment should be the top priority.

Tradeoffs: None

Differing Opinion: The trade off of cap and trade is that the numbers look good, but in reality, the emissions are still in existence.

Burdens:
Regulatory agency needs to be able to collect, verify all emissions information and be able to enforce rule

II. Description of how to implement

A. Mandatory or voluntary
Mandatory

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Agencies and Federal EPA

III. Feasibility of the option

A. Technical: NO_x emissions are measured using CEMS by large Power Plants. Complete and verified emissions measurements are reported by the Four Corners area power plants and is available on the EPA Clean Air Markets: Data and Maps National Database: http://cfpub.epa.gov/gdm/

B. Environmental: NO_x control technologies are available.
C. Economic: The design and operation of the program are relatively simple which helps keep compliance and administrative costs low. Cost savings are significant because regulators do not impose specific reductions on each source. Instead, individual sources choose whether and how to reduce emissions or purchase allowances. Regulators do not need to review or need to approve sources' decisions, allowing them to tailor and adjust their compliance strategies to their particular economics (1). Power Plants may need retrofits or to buy or sell credits.

* Cumulative Effects Work Group: How would a 5% declining cap and trade program for NO_x in the Four Corners area affect visibility and ozone levels?

IV. Background data and assumptions used

1. EPA Clean Air Markets – Air Allowances
http://www.epa.gov/AIRMARKET/trading/basics/index.html

A cap and trade program also is being used to control SO_2 and nitrogen oxides (NO_x) in the Los Angeles, California area. The Regional Clean Air Incentives Market (RECLAIM) program began in 1994. [1]

2. NO_2 emissions from Four Corners area power plants
(4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
*NO_x emissions from existing power plants obtained from EPA Acid Rain database
*NO_x emissions from proposed Desert Rock Energy Facility from AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)

3. EPA Clean Air Markets: Data and Maps National Database: http://cfpub.epa.gov/gdm/

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups
Declining Cap and Trade program would cross-over with Oil & Gas work group.

Mitigation Option: Four Corners States to join the Clean Air Interstate Rule (CAIR) Program

I. Description of the mitigation option

EPA finalized the Clean Air Interstate Rule (CAIR) on March 10, 2005. It is expected that this rule will result in the deepest cuts in sulfur dioxide (SO_2) and nitrogen oxides (NOx) in more that a decade (1).

The Clean Air Interstate Rule establishes a cap-and-trade system for SO_2 and NO_x based on EPA's proven Acid Rain Program. The Acid Rain Program has produced remarkable and demonstrable results, reducing SO_2 emissions faster and cheaper than anticipated, and resulting in wide-ranging environmental improvements. EPA already allocated emission "allowances" for SO2 to sources subject to the Acid Rain Program. These allowances will be used in the CAIR model SO2 trading program. For the model NOx trading programs, EPA will provide emission "allowances" for NOx to each state, according to the state budget. The states will allocate those allowances to sources (or other entities), which can trade them. As a result, sources are able to choose from many compliance alternatives, including: installing pollution control equipment; switching fuels; or buying excess allowances from other sources that have reduced their emissions. Because each source must hold sufficient allowances to cover its emissions each year, the limited number of allowances available ensures required reductions are achieved. The mandatory emission caps, stringent emissions monitoring and reporting requirements with significant automatic penalties for noncompliance, ensure that human health and environmental goals are achieved and sustained. The flexibility of allowance trading creates financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and improve the effectiveness of pollution control equipment (1).

While most of the states are in the Eastern half of the US, Texas is participating in the CAIR program. Four Corners states could also participate and realize the emissions reduction benefits of CAIR.

SO_2 and NO_x contribute to the formation of fine particles and NO_x contributes to the formation of ground-level ozone. Fine particles and ozone are associated with thousands of premature deaths and illnesses each year. Additionally, these pollutants reduce visibility and damage sensitive ecosystems (1).

By the year 2015, the Clean Air Interstate Rule will result in (Eastern US benefits) (1):
-- $85 to $100 billion in annual health benefits, annually preventing 17,000 premature deaths, millions of lost work and school days, and tens of thousands of non-fatal heart attacks and hospital admissions.
-- nearly $2 billion in annual visibility benefits in southeastern national parks, such as Great Smoky and Shenandoah.
-- significant regional reductions in sulfur and nitrogen deposition, reducing the number of acidic lakes and streams in the eastern U.S.

Based on an assessment of the emissions contributing to interstate transport of air pollution and available control measures, EPA has determined that achieving required reductions in the identified states by controlling emissions from power plants is highly cost effective (1).

States must achieve the required emission reductions using one of two compliance options: 1) meet the state’s emission budget by requiring power plants to participate in an EPA-administered interstate cap and trade system that caps emissions in two stages, or 2) meet an individual state emissions budget through measures of the state’s choosing (1).

CAIR provides a Federal framework requiring states to reduce emissions of SO_2 and NO_x. EPA anticipates that states will achieve this primarily by reducing emissions from the power generation sector.

These reductions will be substantial and cost-effective, so in many areas, the reductions are large enough to meet the air quality standards.

The Clean Air Act requires that states meet the new national, health-based air quality standards for ozone and PM2.5 standards by requiring reductions from many types of sources. Some areas may need to take additional local actions. CAIR reductions will lessen the need for additional local controls (1).

This final rule provides cleaner air while allowing for continued economic growth. By enabling states to address air pollutants from power plants in a cost effective fashion, this rule will protect public health and the environment without interfering with the steady flow of affordable energy for American consumers and businesses.

CAIR Timeline:
Promulgate CAIR Rule 2005, State implementation Plans Due 2006, Phase I Cap in Place for NOX, Phase I Cap in Place for SO2, Phase II Cap in Place for NOx and SO_2 (1). Caps will be fully met in 2015 to 2020, depending on banking.

The Four Corners area has existing and proposed power plants with significant NO_x and SO_2 emissions. The problem occurs over a relatively large area, there are a significant number of sources responsible for the problem, the cost of controls varies from source to source, and emissions can be consistently and accurately measured. Cap and Trade programs typically work better over broader areas. The Four Corners area as well as each state would realize a more successful Cap and Trade program from being a part of a large interstate program such as CAIR.

By joining the EPA CAIR program, the 4 Corner states of New Mexico, Colorado, Arizona, and Utah will also benefit from the interstate SO_2 and NOx emissions reductions.

Need some discussion on how to set cap, and protect against hot spots.

<u>Benefits:</u>
"If states choose to meet their emissions reductions requirements by controlling power plant emissions through an interstate cap and trade program, EPA's modeling shows that (for eastern states):

- In 2010, CAIR will reduce SO_2 emissions by 4.3 million tons -- 45% lower than 2003 levels, across states covered by the rule. By 2015, CAIR will reduce SO2 emissions by 5.4 million tons, or 57%, from 2003 levels in these states. At full implementation, CAIR will reduce power plant SO_2 emissions in affected states to just 2.5 million tons, 73% below 2003 emissions levels.
- CAIR also will achieve significant NOx reductions across states covered by the rule. In 2009, CAIR will reduce NOx emissions by 1.7 million tons or 53% from 2003 levels. In 2015, CAIR will reduce power plant NOx emissions by 2 million tons, achieving a regional emissions level of 1.3 million tons, a 61% reduction from 2003 levels. In 1990, national SO_2 emissions from power plants were 15.7 million tons compared to 3.5 million tons that will be achieved with CAIR. In 1990, national NO_x emissions from power plants were 6.7 million tons, compared to 2.2 million tons that will be achieved with CAIR (1)."

<u>Tradeoffs:</u> None
<u>Burdens:</u> Administrative costs on regulating agencies, including how to determine state or regional level cap; emissions control upgrade costs or purchasing allowances to power plants

<u>II. Description of how to implement</u>
A. <u>Mandatory or voluntary</u>

Mandatory emission caps, stringent emissions monitoring and reporting requirements with significant automatic penalties for noncompliance, ensure that human health and environmental goals are achieved and sustained (1).

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Agencies and Federal EPA

III. Feasibility of the option

A. Technical: NOx emissions are measured using CEMS by large Power Plants. Complete and consistent emissions measurement and reporting by all sources guarantees that total emissions do not exceed the cap and that individual sources' emissions are no higher than their allowances

B. Environmental: NO_x, SO_2 control technologies are available.

C. Economic: The design and operation of the program are relatively simple which helps keep compliance and administrative costs low (2).

Cost savings are significant because EPA does not impose specific reductions on each source. Instead, individual sources choose whether and how to reduce emissions or purchase allowances. EPA does not review or need to approve sources' decisions, allowing them to tailor and adjust their compliance strategies to their particular economics (2).

The flexibility of allowance trading creates financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and improve the effectiveness of pollution control equipment (1).

IV. Background data and assumptions used

1. EPA Clean Air Interstate Rule: http://www.epa.gov/cair/
2. EPA Clean Air Markets – Air Allowances
http://www.epa.gov/AIRMARKET/trading/basics/index.html
3. "EPA Enacts Long-Awaited Rule To Improve Air Quality, Health" Rick Weiss, Washington Post, Friday, March 11, 2005; Page A01 http://www.washingtonpost.com/wp-dyn/articles/A23554-2005Mar10.html
4. The White House – Council on Environmental Quality, Cleaner Air,
http://www.whitehouse.gov/ceq/clean-air.html

V. Any uncertainty associated with the option

Low – Program is based on a proven cap and trade approach
Need mechanism to be assured that a significant portion of actual reductions are achieved in the Four Corners area to assure the environmental benefit.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups

Clean Air Interstate Rule would cross-over with Oil & Gas work group

OVERARCHING: ASTHMA STUDIES

Mitigation Option: Chronic Respiratory Disease Study for the Four Corners area to determine relationship between Air Pollutants from Power Plants and Respiratory Health Effects

I. Description of the mitigation option

This option would involve conducting a chronic respiratory disease study for the Four Corners area to determine the relationship between air pollutants from power plants and respiratory health effects. On going studies are necessary to continue to evaluate health risks associated with the large number of combustion emission sources in the area, primarily the two large coal-fired power plants in the area. Cumulatively, the two largest power plants in the area emit approx 66,000 tons/yr of nitrogen oxides (1). Nitrogen oxides are key precursor emissions to ozone.

Background

The NM Department of Health conducted a pilot project that linked daily maximum 8-hour ozone levels with the number of asthma-related emergency room visits at San Juan Regional Medical Center located in northwestern NM. The ozone and ER asthma data were collected for the period of 2000 - 2003. The number of emergency room visits in the summer increased 17% for every 10 ppb increase in ozone levels. This relationship occurred particularly following a two day lag and was statistically significant. These results are in general agreement with studies in other states and provide a foundation for tracking asthma-ozone relationships over time and space in NM (2).

The New Mexico Environment Department Air Quality Bureau operates and maintains three continuous ozone monitors in San Juan County. The eight-hour ozone design value in San Juan County has been maintained below the National Ambient Air Quality Standard for ozone of 0.08 ppm. The final eight-hour ozone design value for 2005 for San Juan County (San Juan Substation and Bloomfield monitors) was 0.072 ppm. The 2006 eight-hour ozone design value for San Juan County Substation monitor was 0.071 ppm. The 2006 eight-hour ozone design value for the San Juan County Bloomfield monitor was 0.069 ppm.

The Colorado Department of Public Health and Environment (CDPHE) has also researched asthma and links to environmental conditions. In a recent paper, "Holistic Approaches for Reducing Environmental Impacts on Asthma", CDPHE, discusses staff researcher's efforts to bring clarity to any identifiable linkage between environmental conditions and asthma. CDPHE investigated asthma rates throughout the state and compared these data against known and anecdotally reported information. Findings indicate that regions of Colorado do appear to have a higher incidence of asthma rates. In addition, some of the identified regions were not previously anticipated (e.g., rural communities), highlighting the need for further investigations (4).

The study describes asthma as a serious, chronic condition that affects over 15 million people in the United States. Asthma is a disease characterized by lung inflammation and hypersensitivity to certain environmental "triggers" such as pollen, dust, humidity, temperature and various environmental pollutants (dust, ozone, etc.), among others. Colorado has a particular problem with the occurrence of this condition, but the reasons for this are not well understood. Statewide there are an estimated 283,000 people with asthma, a figure that well exceeds national expectations. (4).

The CO-benefits risk assessment (COBRA) model is a recently developed screening tool that provides preliminary estimates of the impact of air pollution emission changes on ambient particulate matter (PM) air pollution concentrations, translates this into health effect impacts, and then monetizes these impacts

(5). A model such as this could be expanded to include other forms of air pollution such as ozone and be customized for the Four Corners Area.

Overarching modeling results should be cross-checked with local hospital inventory results and compared with other locations in the United States.

Benefits: Study would allow Four Corner area planning agencies to make better decisions and give the public a better idea of risk assessments

Tradeoffs: None

Burdens: Resources needed to conduct study

II. Description of how to implement

A. Mandatory or voluntary
Conduct coordinated outreach to obtain grant funding for the study.
(Study to be conducted by the end of 2009, with model development for assessing situation annually)

B. Indicate the most appropriate agency(ies) to implement
The states, the Environmental Protection Agency (EPA), and American Lung Association collaboration.

The need for these studies is obvious and the cost should be passed on to the utilities (and therefore the customers). However, even if these new studies find a significantly negative relationship between chronic respiratory disease and air pollutants, we already have proof that air pollutants increase the incidence of asthma. This mitigation option should include plans to utilize the study results for actively engaging policy-makers and changing regulations and enforcement, especially in geographic hot spots.

III. Feasibility of the option (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

Technical: The state and federal health organizations should be able to develop a 4C area model to assess the relationship between air pollutants from power plants and respiratory health effects

Environmental: Need for further modeling of Four Corners area customized to assessing respiratory health effect relationship to air pollutants from power plants. Existing COBRA model may be used as a starting point.

Economic: Grant funding would be required

*Monitoring work group: Assess whether or not we have the adequate data from monitoring stations to assess asthma situation. VOC and NOx emissions are contributors to ozone. Do we have good VOC data in the 4C area?

*Cumulative Effects work group: Assess the ozone trends in the 4C area. On average are ozone levels increasing or decreasing? Where are locations in the Four Corners area with the highest ozone concentrations? What are the relative contributions from power plants compared to oil and gas & other sources?

IV. Background data and assumptions used

(1) EPA Clean Air Markets – Data and Maps Query (2004 2005 2006 Facility & Unit Emissions Reports)
(2) New Mexico Department of Health Ozone Study
(3) New Mexico Environment Department – Ambient Ozone Level Data

(4) Holistic Approaches for Reducing Environmental Impacts on Asthma, Paper # 362, Prepared by Mark J. McMillan, Mark Egbert, and Arthur McFarlane, Colorado Department of Public Health and Environment.
(5) User's Manual for the CO-Benefits Risk Assessment (COBRA) Screening Model, US EPA, June 2006

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups Oil and Gas and Other Sources Work Groups

OVERARCHING: CROSSOVER

Mitigation Option: Install Electric Compression

I. Description of the mitigation option

Overview

- Electric Compression would involve the replacement or retrofit of existing internal combustion engines or proposed new engines with electric motors. The electric motors would be designed to deliver equal horsepower to that of internal combustion engines. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression.

According to projections, at least 12,500 new gas wells will be drilled in the San Juan Basin over the next 20 years. It is said that this gas field is loosing pressure and compression on thousands of wells is necessary. Pollution emissions from production engines are rapidly increasing. To date, there is no cumulative emissions measurement.

Using BLM figures, an average gas powered wellhead compressor at 353,685 hp-hr per year at 13.15g per hp-hr = 4,650,957 g/year of NO_x. This is just an example of NO_x emissions. This figure does not account for other compounds in exhaust emissions such as VOCs, carbon monoxide, etc. This is equivalent to a 17 car motorcade running non-stop, circling your house 24 hours per day.

Gas powered wellhead compressors and pumpjacks are being installed in close proximity to inhabited homes and institutions. The City of Aztec required electric compressors, although that ordinance was not enforced, on wellhead engines within the city limits prior to 2004 when the ordinance was revised. Electric engines were required in order to protect citizens from noxious emissions from gas fired engines near homes. Electric engines are thought to be quieter than gas fired engines; therefore reducing noise pollution also.

Gas fired engines are being installed on wells in close proximity to existing electric lines. Electric engines should be required on all sites near power lines especially near homes. In areas where there is no electricity, best available technology must be implemented such as 2g/hp/hr engines, catalytic converters, etc.

Air Quality/Environmental

- Elimination of criteria pollutants that occur with the combustion of hydrocarbon fuels (natural gas, diesel, gasoline). Displacement of emissions to power generating sources (utilities).

Economics

- The costs to replace natural gas fired compressors with electric motors would be costly.
- The costs of getting electrical power to the sites would be costly. It could require a grid pattern upgrade which could costs millions of dollars for a given area.
- A routine connection to a grid with adequate capacity for a small electric motor can be $18K to $25K/site on the Colorado side of the San Juan Basin.
- A scaled down substation for electrification of a central compression site can range between $250K and $400K.
- Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

Tradeoffs

- While the sites where the electrical motors would be placed would not be sources of emissions, indirect emissions from the facilities generating the electricity would still occur such as coal fired power plants.
- Additional co-generation facilities would likely have to be built in the region to supply the amount of electrical power needed for this option. This would result in additional emissions of criteria pollutants from the combustion of natural gas for turbines typically used for co-generation facilities.
- There would need to be possible upgrades in the electrical distribution system. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression

Burdens

- The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time.
B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies.

III. Feasibility of the option

A. Technical: Feasible depending upon the electrical grid in a given geographic area
B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Indirect emission implications for grid suppliers should be considered (e.g., coal-fired plants).
C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site.

IV. Background data and assumptions used

The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

V. Any uncertainty associated with the option

Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies.

*A cumulative emissions inventory on all oil and gas field equipment is necessary
*If possible, a calculation of pollution related to electric power generation is needed for comparison to pollution emitted from gas powered engines.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other source groups

Oil and Gas Work Group
Cumulative Effects Work Group
Power Plant Work Group

OVERARCHING: CROSSOVER OPTIONS

Mitigation Option: Economic-Incentives Based Emission Trading System (EBETS) (Reference as is from Oil and Gas: see Oil and Gas Overarching Section)

Mitigation Option: Tax or Economic Development Incentives for Environmental Mitigation (Reference as is from Oil and Gas: see Oil and Gas Overarching Section)

FOUR CORNERS AREA POWER PLANTS FACILITY DATA TABLE

This data table was prepared by the Power Plants Work Group as a resource to help develop mitigation options. Facility data information was compiled from a variety of sources (see references). The last update of the table was August 2007. The Table, along with other resource information on Four Corners area power plants, is also available on the Task Force Website on the Power Plants Work Group Page, http://www.nmenv.state.nm.us/aqb/4C/powerplant_workgroup.html

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010 [10]
San Juan Generating Station [1]	PNM Resources (Owner/Operator)	Coal	ARP, EPA 9, Western Systems Coordinating Council	NMED - AQB	4 units, 1798 MW	PM- ESP	PM – 673 tons (2005)		PM – baghouse	13,097,406 tons (2005)	PM - 670 tons/yr
						SO_x - Wet Limestone	SO_2 – 16,570 tons (2005)	SO_2 – 16,179.3 tons (2004), 16,569.5 tons (2005) [4]	SO2 – enhanced scrubbing		SO2 - 8,900 tons/yr
						NO_x – Low-NOx burners / Over-fired air	NO_x – 26,809 tons (2005)	NO_x – 26,880.2 tons (2004), 26,809.0 tons (2005) [4]	NO_x – low-NO_x burners/ over-fired air / neural net		NOx - 18,500 tons/yr
						Hg – Wet scrubber	Hg – 766 lbs (2005)	CO_2 – 13,147,181.0 tons (2004), 13,097,410.1 tons (2005) [4]	Hg – activated carbon. Hg – CEMs		Hg - 275 lbs/yr
Four Corners Power Plant [2,3]	Arizona Public Service Company (Owner/Operator)	Coal	ARP, EPA 9	EPA Region 9, Navajo Nation EPA	5 units, 2040 MW	Units #1 - #3:	PM – 1,187 tons (2000-2005 annual average)		Considering available technologies for future regulatory changes [3]	15,913,105 tons (2000-2005 annual average)	N/A
						PM - Wet venturi scrubbers	SO_2 – 12,500 tons (2005)	SO_2 – 18,771 tons (2004), 12,554.2 (2005) [4]			

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Four Corners Power Plant [2,3] (cont.)						SOx - Dolomitic lime wet scrubbing	NO_x – 42,000 tons (2000-2005)	NO_x – 40,742 tons (2004), 41,743.4 tons (2005)			N/A
						NO_x – Low-NOx burners	Hg – Approx. 550-600 lbs/yr	CO_2 – 15,106,255 tons (2004), 16,015,408.7 tons (2005) [4]			
						Hg – Venturi scrubber					
						Units #4 & #5:					
						PM – Baghouses					
						SOx – Lime slurry wet scrubbing					
						NOx – Low-NOx burners					
						Hg – Wet scrubber, baghouses					
Proposed Desert Rock Energy Facility [5, 12]	Sithe Global Power, LLC (proposed owner/operator)	Coal		EPA Region 9, Navajo Nation EPA	2 units, 1500 MW [5]	PM – Baghouse [6, 12][1]	PM (TSP/PM) – 570 Tons/yr [6,12][3]		Hg – activated carbon if control < 90% and cost < $13,000/lb**	Approx. 12,700,000 tons/yr[8]	N/A
							PM_{10} – 1,120 Tons/yr [6, 12][4]				
						SOx –Wet Limestone FGD [6, 12][1]	SO_2 – 3,319 Tons/yr [6, 12]				
						NOx – low-NOx burners/ over-fired air / SCR [6,12]	NO_x – 3,325 Tons/yr [6, 12]				

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Proposed Desert Rock Energy Facility [5, 12] (cont.)						Hg – SCR +baghouse +FGD[2] [6, 12]	Mercury – 114 lbs/ yr [12]				N/A
							CO – 5,529 Tons/yr [12]				
						Hydrated Lime Injection & Wet Limestone FGD [12]	Lead – 11.1 Tons/yr [12] Flourides – 13.3 Tons/yr [12]				
						Hydrated Lime Injection & Wet Limestone FGD [12]	H_2SO_4 – 221 Tons/yr [12]				
Bluffview Power Plant [4]	City of Farmington (Owner/Operator) (Started 28-JUL-05)	Pipeline Natural Gas / Cogeneration	ARP, EPA 6		60 MW	Dry Low NOx Burners, Selective Catalytic Reduction		SO_2 – 0.7 tons/yr (2005) [4]		145997.3 tons (2005) [4]	N/A
								NO_x – 58.5 tons/yr (2005) [4]			
Milagro [4]	Williams Field Services (Owner/Operator)	Pipeline Natural Gas / Cogeneration	ARP, EPA 6		2 units, 61 MW [11]			SO_2 – 2.6 tons (2004), 2.5 tons (2005) [4]		498823.3 tons (2005) [4]	N/A
						NO_x – Dry Low-NOx burners		NO_x – 97.6 tons (2004), 110.2 tons (2005) [4]			

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Animas Power Plant [9]	City of Farmington (Owner/Operator)	Pipeline Natural Gas / Cogeneration	EPA 6, Western Systems Coordinating Council		51 MW [9]		SO2 – 0 (2005, turbine only) NOx – 54 Tons (2005, turbine) VOC – 54.3 Tons (2005, turbine) CO – 5.1 Tons (2005, turbine)				N/A
Bloomfield Generation [4]	Ameramex Energy Group, Inc. (Owner/Operator)		ARP, EPA 6								N/A
Navajo Dam Hydro Plant [9]	City of Farmington (Owner/Operator)	Water			30 MW [9]						N/A
Mustang Energy Project[7][5]	Proposed	Coal			300 MW		PM - 185 tons/yr SO_2 – 250 tons/yr NO_X - 125 tons/yr			Approx. 2,000,000 tons/yr[8]	N/A

[1] May 23, 2006 edit, info provided by Mike Farley (PNM), and in SJGS presentation for 4CAQTF, "SJGS Emissions Control Current and Future" http://www.nmenv.state.nm.us/aqb/4C/Docs/SanJuanGeneratingStation.pdf
[2] http://www.aps.com/general_info/AboutAPS_18.html [dl 5/29/06]
[3] APS Four Corners Power Plant tour handout (received 5/10/06), supplemental info provided by Richard Grimes (APS), in May 31 table edit
[4] EPA Clean Air Markets – Data and Maps Query (2004 2005 2006 Facility & Unit Emissions Reports)

[5] SITHE GLOBAL Desert Rock Energy Project FACT SHEET #1 DEC 2004 [dl 5/29/06]
[6] Application for Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility, prepared by ENSR International May 2004
[7] Reference to Dave R. edits 6/2/06
[8] Desert Rock Energy Project Draft EIS Ch. 4.0 – Environmental Consequences May 2007
[9] Farmington Electric Utility Fact Sheet http://206.206.77.3/pdf/electric_utility/feus_fact_sheet.pdf (6/16/06) / NMED
[10] Info provided by Mike Farley (PNM)
[11] http://www.emnrd.state.nm.us/EMNRD/MAIN/documents/SER1_electricity.pdf
[12] AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01), Table 1, EPA Region 9 Air Programs: http://www.epa.gov/region09/air/permit/desertrock/#permit

[1]Subject to BACT - Best available control technology [6]
[2]Mercury (Hg) and HCL have been targeted under future regulation under maximum available control technology (MACT) [6]
[3]PM is defined as filterable particulate matter as measured by EPA Method 5.
[4]PM10 is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. EPA is treating PM10 as a surrogate for PM2.5.
[5]Outside of Scope of Work, Not located in 4CAQTF study area

POWER PLANTS: PUBLIC COMMENTS

Power Plants Public Comments

Comment	Mitigation Option
I have been concerned for many years about the air quality of the Four Corner's region because of the coal fired power plants in N.M. I attended two of the Four Corner's air quality forums in the past and was disturbed by their reports. As a nurse, I am especially concerned for the health of the Native Americans and other people who reside close to the power plants because of their incidence of lung disease. As a resident of La Plata canyon for 20+ years with a high mercury level, I am concerned about my own health and notice more air pollution, lack of visibility, every time I hike in the mountains. I believe for everyone's health, alternative sources of energy; e.g. solar, wind energy is a much better solution and would still serve as a revenue source to the Navajo nation. Desert Rock should not be built and the others should be phased out as planned many years ago or at least upgraded to standards that were set by the Clinton administration.	General Comment
We do NOT need another power plant in the 4 Corners. I notice the dirty air in this area all of the time and especially on weekends. Drive up from Albuquerque and see the air get dirtier. Also, go out from the 4 Corners and notice the beautiful blue skies as you progressively leave the area. I teach school and stress to my students they need to take care of the this planet earth because there is no spare earth. I would like to stress to everyone else that this needs to be done. Solar, wind and other energy sources should be used.	General Comment
It saddens me and concerns me for our children's futures and the native American leaders who think that this is progress and prosperity for their people. The leaders are once again selling out their people for the promise of temporary jobs and profits. How can we as a educated people agree to allow this plant in today's environment? Mercury in our children's blood and more carbons in the air are a horrible price to pay for short term gains in energy downstream. How can Governor Richards speak of the environment while he is silent on this issue. I will not be able to attend any public meetings and would appreciate my view forwarded if possible. I am a mother, grandmother and previous medical office manager. Most importantly, I am a voter.	General Comment
It breaks my heart to think that another coal fired plant may be added to our "pristine" 4 corners area. Even in Pagosa Springs we have some hazy smog some days, and when driving south and west of Farmington, that horrible yellow-brown cloud can be seen for miles! I was shocked to see that poisonous cloud in Monument valley, and northwest Utah. It's all pervasive now so I can't imagine what it will be like with more coal -spewing plants. We must use non polluting energy sources for the health of all of us!	General Comment

Comment	Mitigation Option
Desert Rock Energy LLC (Desert Rock) appreciates the opportunity to submit the following comments on the Four Corners Air Quality Task Force Draft Report. Desert Rock supports the Task Force's efforts to promote air quality mitigation in the Four Corners area. Desert Rock is committed to air quality mitigation, and has designed the proposed Desert Rock Facility to minimize impacts while providing needed electricity and additional economic development to the Navajo Nation. As detailed in the Draft Task Force Report, the proposed Desert Rock Facility is a 1,500 MW mine mouth power plant being developed by Sithe Global Power, Desert Rock Energy Company, and the Dinè Power Authority (an enterprise of the Navajo Nation). It is designed to burn low BTU, low sulfur subituminous Navajo coal. The plant will be located at an elevation of 5,415 feet. It will be one of the most efficient plants in the US, with two supercritical pulverized coal-fired boilers operating at a net heat rate of 8,983 Btu/kWh. The plant will be required to operate with very low emission rates, including 0.06 lb/MMBtu for both NOx and SO2 and 0.01 lb/MMBtu for filterable PM, all on a 24-hour average. The plant will also use dry cooling to reduce water consumption by 80 percent. EPA has stated that the Desert Rock Facility will have the lowest emission rates of any coal-fired project in the US. These emission rates will be even lower than emission rates associated with IGCC. Desert Rock is committed to engaging in regional air quality improvement initiatives. In fact, Desert Rock has already invested significant time and resources participating in such initiatives. Desert Rock has worked with the National Park Service, the National Forest Service, EPA, the Navajo National Environmental Protection Agency, and other governmental stakeholders to create a mitigation plan that will offset all SO2 emissions from the facility and further reduce mercury impacts. Below is a description of this regional effort: 1. Desert Rock Energy has agreed to a Voluntary Regional Air Quality Improvement Plan with the US EPA, US Forest Service, National Parks Service, and the Navajo Nation Environmental Protection Agency. 2. The Improvement Plan requires Desert Rock to reduce regional SO2 emission and visibility impacts by one of three (3) mechanisms: 1) Regional SO2 Control, 2) Regional NOx Control, or 3) Procurement and retirement of SO2 Allowances. a. Under an SO2 control-sponsored project, the implementation of this plan will result in a net improvement of the local environment. The plan, not only will totally offset the SO2 emissions of Desert Rock (3,315 tons of SO2), it will also remove an additional 330 tons of SO2 from the local atmosphere, for a total reduction of 110%. b. If an SO2 control project cannot be developed, Desert Rock may implement a NOx control-sponsored project which will remove NOx emissions in the region by 100% of Desert Rock NOx emissions plus approximately an additional 7500 tons. c. If Desert Rock is not able to invest in capital projects at other plants to reduce SO2 or NOx emissions, Desert Rock has reserved capital to purchase and retire up to $3,000,000 per year in SO2 allowances for the life of the project. The acquisition of these allowances is beyond those that are required under the Acid Rain program.	General Comment

Comment	Mitigation Option
3. Mercury control of at least 80% will be achieved. Additional investments in Mercury control technology to reach a target of 90% control will be made subject to plan limitations. If the 90 % control target is met, it will reduce mercury emissions an additional 50 percent from approximately 160 lbs per year to approximately 80 lbs per year. 4. The local area will benefit from Desert Rock's annual environmental contributions that may be available subject to plan limitations. Such contributions could be used to advance the local environmental science and planning as well as sponsor projects that reduce greenhouse gas emissions, add further mercury control, increase monitoring, support the Four Corners Task Force, or contribute to any other environmental project determined to be of great value to the region. Desert Rock objects to the language in the Draft Report stating that "[t]he uncertainty [about the mitigation plan] involves how stakeholders can be assured the measures will actually happen." Desert Rock has made a public commitment to implement this mitigation plan and, in order to reassure all stakeholders of its commitment, is in the process of working with Federal agencies and the Navajo Nation to ensure that this mitigation plan is federally enforceable. The Desert Rock Facility will therefore be held accountable for fulfilling its mitigation commitments. In light of the mitigation plan, the Draft Report is incorrect in saying that "[w]hile the Desert Rock Energy Facility is using newer environmental emission control technology that on average have higher reduction efficiencies than existing facilities, the proposed power plant will still be adding substantial NO2, SO2, particulate, and other emissions to the Four Corners Area." It is quite likely that, because of the mitigation plan, either SO2 or NOx emissions in the area will actually be reduced. Although there will be a very small increase in emissions of other pollutants, the amounts are so small that the Plant will not have an appreciable impact on air quality in the Four Corners area. Discussion of CO2 Emissions Desert Rock believes that global climate change is a very serious issue and is committed to working with governments and industries to develop laws and policies - and most importantly, advanced technologies - that will reduce anthropogenic emissions of CO2 and other greenhouse gases. Indeed, as discussed below, we are actively exploring options that may allow us to capture and sequester CO2 emissions from the plant at some point in the future. We are concerned, however, about the discussion of CO2 emissions in the Draft Report. The Report is designed to address air quality issues in the Four Corners area, and it is simply misleading to suggest that CO2 is an air quality issue. CO2 emissions in New York and New Delhi will have precisely the same impact on climate change in the Four Corners Region as CO2 emissions from Desert Rock. By addressing CO2 without making a clear distinction between air quality (which is largely a local and regional issue) and climate change (which is entirely a global issue), the Report will actually be misleading to many readers who are not fully informed about the nature of climate change.	

Comment	Mitigation Option
IGCC and Desert Rock The Draft Report includes a discussion of Integrated Gasification Combined Cycle (IGCC) technology that is not appropriate for the Desert Rock Facility. We are concerned that it will mislead readers into thinking that IGCC would be a better environmental choice for the Four Corners area, when this is simply not the case. The EPA Report cited in the Report does not address the issues involved in building an IGCC plant (or a modern supercritical pulverized coal plant) with the type of coal available in the Four Corners area or at an altitude anywhere near the elevation of the Desert Rock Facility. Not only technical experts with Desert Rock Energy, but other technical experts have concluded that there would be serious technical challenges involved in trying to operate an IGCC plant at a site like the Desert Rock Facility. The Report suggests that, at a minimum, Desert Rock should have been required to evaluate IGCC as part of the BACT process. Desert Rock did, in fact, evaluate the potential use of a range of modern coal technologies including IGCC. Nothing more would be learned by formally including such an evaluation in the BACT process. Desert Rock determined that the use of modern supercritical pulverized coal boilers is the best option, not only in terms of cost and reliability, but from an environmental standpoint as well. This technology is proven, reliable, and highly efficient and, in combination with an extensive array of pollution control equipment, will be a leader in reducing emissions from coal combustion. EPA has again stated that the Desert Rock Facility will have the lowest emissions rate of any coal-fired project in the US. As discussed below, there would be no material difference in emissions - including CO2 and other green house gas emissions - with an IGCC plant at the Desert Rock site assuming current IGCC technology performance. Though IGCC is an evolving technology, IGCC does not currently meet the need for reliable and economical power production. There are only four operating coal-fired IGCC plants in the world, two in the United States both which use petroleum coke and not coal as the fuel source. Other IGCC projects in the US were built as small scale (less than 300 megawatts) demonstration projects with substantial government funding and some faced such severe operating problems that they never reached commercial operation. Even the facilities that did achieve commercial operation have not met projections for cost, efficiency, reliability and environmental performance. The "next generation" of IGCC plants, currently in development, with commercial operation dates planned in the 2011-2015 period, are in the 300-600 megawatt range. It remains to be seen if the next generation of IGCC plants will meet the cost and reliability targets needed to provide reliable, low cost power. There are also many engineering issues that remain to be solved in using low BTU high ash coals such as those found in New Mexico to fuel IGCC plants. Reliability - The IGCC units currently in operation have a poor reliability records. It remains to be seen if the next generation of IGCC plants will face similar reliability issues. The "integrated" part of IGCC refers to the integration of a gasifier and a combined cycle power plant to transform the	

Comment	Mitigation Option
coal into syngas and combust that syngas to produce electricity. This integration introduces numerous additional potential engineering points of failure and, as a result, there is a record of poor performance. Several of the IGCC units in operation have been able to reach the 80% reliability level but only after five to ten years of operation. In contrast, supercritical technology proposed for Desert Rock has a proven performance record of 90% or better, beginning in its first year of operation. Cost - Projections of life cycle capital and operating costs for IGCC plants in the 600 to 2,000 megawatt range are substantially higher than supercritical technology. These have demonstrated that the cost of a 1,500 megawatt IGCC plant is approximately 30-40% higher than a similarly-sized supercritical pulverized coal plant. Desert Rock would cost $1 billion more built using IGCC technology. Efficiency - The technology proposed for the Desert Rock Facility is highly efficient, meaning substantially less coal is used to produce the same amount of electricity with fewer emissions than older, conventional coal fired power plants. Desert Rock's proposed technology is also more efficient than current IGCC plants. For example, the technology proposed for the Desert Rock Facility is approximately 15% more efficient than the present IGCC facilities in Florida and Indiana, meaning it will use 15% less coal to produce a similar amount of electricity on an average annual basis. In comparison to recently filed air permit applications for the "next generation" IGCC plants, the Desert Rock Facility will have comparable efficiencies when the IGCC efficiency losses of operating at above 5,000 ft above sea level are taken in account. Emissions - Due to the high efficiency of the Desert Rock Facility's generating technology and the extensive array of pollution control equipment incorporated into its design, the plant's emission rates compare very favorably to existing IGCC units and are expected to be similar to the "next generation" IGCC plants. IGCC plants do not produce any less greenhouse gasses than a supercritical plant with similar efficiency Desert Rock is also designing the facility to have "future proofing" characteristics, which allow for augmentation of the initial extensive array of emissions control equipment and with more advanced control equipment when the new equipment is demonstrated to be commercially viable. Summary on IGCC - Desert Rock carefully considered all options available before concluding that supercritical pulverized coal technology is the best choice for the facility. The Desert Rock Facility's supercritical design helps to ensure a reliable power supply and lower fuel cost for customers, while being highly protective of public health and the environment. While IGCC is expected to become a viable large scale electric generation technology in the future, it currently lacks the reliability, efficiency, economics, and scale that supercritical technology provides with no material difference in emissions including greenhouse gases Carbon Sequestration and Desert Rock Sithe Global Power, LLC continues to study the technological and commercial implications of carbon capturing and sequestration (CCS) in	

Comment	Mitigation Option
power plant applications. With respect to the Desert Rock Facility, we have participated in numerous discussions with the Department of Energy, various national laboratories, and the major equipment suppliers to evaluate the technological feasibility and economic viability of a large scale CCS project. After extensive discussions, we have been unable to identify a commercially feasible solution. As of today, the major equipment suppliers are unwilling to offer performance guarantees for a large scale CCS project. In addition, an appropriate mechanism to recover the cost of implementation, including the cost of development, installation and operation, has not yet been implemented. As a result, Desert Rock is not in a position to incorporate CCS at this time. Desert Rock intends to continue to participate in the development of CCS and will consider the implementation of CCS once the technology and commercial framework are in place. The major equipment suppliers have an economic incentive to complete the development of the necessary technology. The Task Force can provide a great deal of assistance to help create and promote an appropriate commercial framework. Thank you for the opportunity to provide the above comments on the Draft Task Force Report. Desert Rock is again committed to air quality mitigation and appreciates the Task Force's efforts. If you have any questions or we can be of assistance, please let us know. Sincerely, Dirk Straussfeld Executive Vice President Desert Rock Energy Company, LLC Three Riverway Suite 1100 Houston, Texas 77056 Phone: (713) 499-1155 Fax: (713) 499-1167	

Comment	Mitigation Option
A Mitigation Option should be added for Nuclear technology. We should not assume that it is too controversial for consideration. The U.S. Nuclear Regulatory Commission is staffing up to consider up to 30 nuclear units in fiscal 2008. This was motivated by the Energy Policy Act of 2005, that has invigorated the power industry to come forward with new plans. A new NRC office has been created solely for licensing and oversight of new reactor activities, with a current staff of 240. The most activity for these units will be in the south and southeast, where utilities have on-going nuclear experience. NRC has streamlined their processes so standard design certifications would be approved, and the safety design hurdle would not be raised continually. Most of these applications will be active pump/valve cooling designs that meet the stringent safety requirements of standard design certifications. There is promise for a family of passive cooling reactors, where gravity/density differences provide equivalent cooling protection. These designs would be simpler and less expensive than current active pump designs. Much design work has been done, although there is not currently such a unit in operation. Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s. Benefits: Zero air emissions impact; No carbon footprint; cost effective electricity generation; foster high technology employment basis in Four Corners; proximity to future Nevada spent fuel storage site Tradeoffs: Negative public opinion; spent fuel containment Reference: Energybiz magazine Vol. 4, Issue 3 (May 07, June 07) "Agency Gets Ready for Nuclear Renaissance" -- "Repackaging the Nuclear Option" -- "GE Gears Up"	Proposed Power Plant - Desert Rock Energy Facility
I feel this (and perhaps one or two other power plants options) should be incorporated by reference into the monitoring section. There is a lot of good writing here.	Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits
The monitoring of degrading power plants deserves dual attention; both in this section and in the monitoring section for emphasis.	Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits
The Electric Power Research Institute (EPRI) today announced the beginning of a new project to study the feasibility of concentrating solar power in New Mexico. Unlike conventional flat-plate solar or photovoltaic panels, concentrating solar power (CSP) uses reflectors to concentrate the heat and generate electricity more efficiently. There are four utility-sized CSP plants in the U.S. today; one in Nevada and three in California. Initiated by New Mexico utility PNM and with subsequent interest from other regional utilities, the project will be directed and managed by EPRI. PNM has expressed interest in building a CSP plant in New Mexico by 2010. The feasibility study for a power plant of the 50-500 megawatt (MW) size range is expected to be finished by the end of 2007. The Four Corners area is one of the best areas for solar energy production in the United States and would be an ideal location for a new solar energy plant. For example, in Farmington,	Utility-Scale Photovoltaic Plants

Comment	Mitigation Option
NM a flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees an avg. of 6.3 hours of full sun. The Solar plant could help New Mexico meet renewable energy portfolio standards. San Juan County also has a renewable energy school focusing on solar energy system design and installation. The plant could potentially be an educational/technical resource for the college.	
I would emphatically like to see this option included in the final report.	Reorganization of EPA Regions
The need for these studies is obvious and the cost should be passed on to the utilities (and therefore the customers). However, even if these new studies find a significantly negative relationship between chronic respiratory disease and air pollutants, we already have proof that air pollutants increase the incidence of asthma. This mitigation option should include plans to utilize the study results for actively engaging policy-makers and changing regulations and enforcement, especially in geographic hot spots.	Chronic Respiratory Disease Study for the Four Corners area to determine relationship between Air Pollutants from Power Plants and Respiratory Health Effects

Other Sources

Other Sources: Preface

Overview

The Other Sources Work Group was charged with analyzing emissions mitigation strategies from all industrial, residential and transportation sectors that have emissions that significantly impact air quality in the Four Corners region. Although the work group was small, participation in the group involved state, local and tribal air quality agencies, industry representatives, public citizens, and representatives of environmental organizations.

Organization

The members of the Other Sources Work Group decided to focus on four main topic areas:

1. Transportation, including mobile sources
2. Land use, development, and planning
3. Burning
4. Alternative energy and fuels

Mitigation options for transportation issues included the following: including multi-modal transportation options in the 2035 transportation plan, including the Four Corners region into the Clean Cities designation for the Western Slope, encouraging local organizations to push for new projects and ordinances for transportation issues, developing requirements for anti-idling, school bus retrofits, increasing taxes for dirtier vehicles, developing a regional inspection and maintenance program, retrofitting or replacing oil and gas fleet vehicles, and looking at the Reid vapor pressure of fuels.

For land use, development and planning, the group discussed the consistency of regulations between jurisdictions for construction and sand and gravel operations, developing a regional planning organization for the region, phasing of projects to minimize blowing dust from bladed tracts of land, and developing a fugitive road dust plan.

Burning is handled very differently among the different jurisdictions in the Four Corners region. Mitigation options discussed for burning included public education and outreach, regulating agricultural burning in the Colorado portion of the region, providing a subsidy for cleaner fuels for residential heating, and using filter traps on wood stoves.

The alternative energy and fuels options were developed in conjunction with the Power Plants work group, and are included in the Energy Efficiency, Renewable Energy and Conservation section of this document.

Mitigation Option: Phased Construction Projects

I. Description of the mitigation option

Construction projects remove large quantities of vegetation leaving bare earth open to wind erosion, as well as to other environmental and biological degradation. Phasing these projects, large and even single residential development could lessen this environmental problem. Phasing re-vegetation would also result in decreased wind erosion.

Since phasing includes both small and large projects, this is something that individuals can have a part in as well as participating in for the larger community.

Benefits:

- Air quality – Particulate matter would decrease, protection of scenic views and economic benefits for tourism

- Environmental – Globally desertification is a big concern. The decrease in wind-blown particulates could delay man-made local desertification.

- Economic—construction would be phased according to building. Therefore, upfront costs would be also coordinated with sales, rather than all at the project beginning. Construction loans would also be phased.

Burdens:

- Developers may see change in methods as a threat to free enterprise.

- Construction managers would have to keep grading machinery on site locations throughout the project.

II. Description of how to implement

A. Mandatory or voluntary

Both. Mandatory for new construction. Incentives for individual homeowners to plant vegetation on disturbed sites.

B. Indicate the most appropriate agency(ies) to implement

Counties and towns in land use regulations, building permits. Local and state agencies may also implement programs for free compost or vegetation (e.g., native trees or shrubs for lot sizes over 1 acre).

III. Feasibility of the option

A. Technical – High
B. Environmental – High
C. Economic – High – may result in higher costs for construction projects in some areas.

IV. Background data and assumptions used

Help from monitoring work group to collect data downwind of

V. Any uncertainty associated with the option (Low, Medium, High) – Low

VI. Level of agreement within the work group for this mitigation option.

VII. Cross-over issues to the other source groups

Oil and gas and power plant work groups may look at phased development and revegetation for new projects.

Mitigation Option: Public Buy-in through Local Organizations to push for transportation alternatives and ordinances

I. Description of the mitigation option, including benefits and burdens.
Involve existing local organizations in supporting alternative transportation options. Go to meetings of existing organizations and discuss how they can help to promote clean air. Examples of the type of projects local organizations might support include bike paths, bike racks on buses, carpool lanes, and ride-share.

Benefits of applying this option might include reduced traffic congestion, reduction of fuel use, and boosts to local neighborhood economies. Burdens would be minimal though there may some tax increases may be necessary to fund the projects.

II. Description of how to implement
This would be a voluntary option. Agencies and task force members would implement by participation in local meetings. Publicity to encourage participation in organizations and support for alternatives might also be used. States could use these partnerships as early action compacts for State Implementation Plans.

III. Feasibility of the option
This option would be easy to implement because it is voluntary. While there may be some minimal cost for agencies to participate in local meetings it would be within their mission and a positive use of tax dollars.

IV. Background data and assumptions
The simplicity of this option requires no background analysis. It is assumed that individuals would make the effort to partner with local organizations.

V. Any uncertainty associated with the option
There is little uncertainty that this would be a viable and effective option.

VI. Level of agreement within the Work Group for this option
All work group members agree that this is a worthwhile option.

VII. Crossover issues to other workgroups
Involvement in planning for employee ridesharing may crossover to the Power Plant and Oil and Gas groups.

Mitigation Option: Regional Planning Organization for the Four Corners Region

I. Description of the mitigation option
The Four Corners region has a number of different jurisdictions and requirements. The air quality issues in the region are more widespread than local jurisdictions or agencies can address without working together as a regional planning organization (RPO). What occurs in one jurisdiction affects other jurisdictions, especially with respect to air quality. Although any one jurisdiction may have a very good program, that would be unlikely to have a widespread effect throughout the Four Corners region. The synergies of a region are much greater. In not duplicating efforts, costs will be lessened. States and local jurisdictions must be committed to the work of the RPO. RPO membership should be limited to those who have regulatory authority (e.g., towns, cities, counties, tribal governments, states).

II: Description of how to implement
Members could be appointed by local and/or state governments. Officers could be voted in by the members. Member entities would include the cities/towns of Durango, Farmington, Aztec, Cortez, Bloomfield, and Pagosa Springs; the tribes of Navajo Nation, Southern Ute, Ute Mountain Ute, Jicarilla Apache; and the counties of San Juan and Rio Arriba in New Mexico and Montezuma, La Plata and Archuleta in Colorado.

Meetings of the regional planning organization would be held on a regular schedule (perhaps quarterly) and open to the public. It is important that the governors of the Four Corners states support the organization. Local agencies would brief the governors and the state agencies on the need for a work of the organization. It is possible that this organization could be set up similarly to a Council of Governments organization. One way to begin the conversation to establish the RPO would be to ask the League of Women Voters or other task force members to present this idea to the Northwest New Mexico Council of Governments. Funding could be joint from states, tribes, local governments, and potentially EPA grants.

Another option would be to house this RPO within the Western Governors Association, perhaps similarly to the Western Regional Air Partnership with a scope limited to the Four Corners region.

III. Feasibility of option
If there are 2 or 3 local champions that are willing to dedicate time and energy, this could work. Also, support of the state agencies and governors would be critical.

IV. Background data and assumptions used Assume local governments will be willing to work together on these issues.

V. Any uncertainty associated with the option (Low, Medium, High) Medium, depending on local support.

VI. Level of agreement within the workgroup for this mitigation option Strong.

VII. Cross-over issues to other source groups
No, although it is similar in focus to the Overarching mitigation option on Reorganization of EPA Regions.

Mitigation Option: Develop Public Education and Outreach Campaign for Open Burning

I. Description of the mitigation option

This option involves the development of a public education and outreach campaign that would target the practice of open burning. The goals of this mitigation option are to 1) educate the public on the health dangers associated with open burning, 2) educate the public on the environmental/air quality damages of open burning, and 3) decrease the usage of open burning in the targeted communities.

Open burning is a more serious threat to public health and the environment than what was previously believed. Burning household waste produces many toxic chemicals and is one of the largest known sources of dioxins in the nation. Dioxins are highly toxic, long-lasting organic compounds that are extremely dangerous, even at low levels. Dioxins have been linked to serious health problems, including cancers and developmental and reproductive disorders. Other air pollutants such as particulate matter, sulfur dioxide, lead, mercury and hexachlorobenzene also affect adults and children with asthma or other lung diseases. Diseases related to the nervous system, kidneys and liver have also been linked to these pollutants.

II. Description of how to implement

A. Mandatory or Voluntary: This program would be a voluntary program hosted by local agencies or environmental groups.

B. Indicate the most appropriate agency(ies) to implement: Public Health, Environmental

III. Feasibility of the option

A. Technical: There are many similar open burning education campaigns present in Colorado, therefore it would not be difficult to receive technical support for the option.
B. Environmental: Since we are aware of the environmental dangers associated with open burning, there is much research available to use in educating the public.
C. Economic: Depending on the budget of the agencies, this program should not be prohibitive or expensive.

IV. Background data and assumptions used

1. Data on emissions from open burning was pulled from the EPA's Municipal Solid Waste Web site (www.epa.gov/msw)

V. Any uncertainty associated with the option (Low, Medium, High)

Medium

Mitigation Option: Automobile Emissions Inspection Program

I. Description of the mitigation option

Automobile emissions inspection/maintenance (IM) programs are a traditional mobile source strategy to control automotive emissions. They improve air quality through the identification and repair of high emitting vehicles. Vehicles that are repaired pollute less, improving air quality. They also get better fuel economy that contributes to reducing green house gas emissions.

Inspection/maintenance programs have been used to control automobile emissions since the early 1970s. They were originally used in New Jersey, Arizona and other states as early as 1974. They have been predominantly implemented in areas that are, or have been, out of attainment for ozone or carbon monoxide.

It is estimated that in urban areas, such as Denver or Albuquerque, motor vehicles contribute one-quarter to one-half of all the anthropogenic hydrocarbon and nitrogen oxide emissions, and three-fourths of the carbon monoxide emissions. Even in rural areas, automobiles can be a source for these emissions. Control of these emissions will reduce ozone concentrations, dependent on factors such as the NOx/HC ratio, amount of solar radiation, and meteorology/air mass movement and vertical mixing. Of importance is the fact that mobile source hydrocarbon emissions generally are higher in ozone reactivity (ability to make ozone) than other sources, such as natural gas production, thus may be important to control.

Table 1
2007 Denver metro VOC and NOx inventories
(tons per day)

	Mobile Inventory	Total Inventory
VOC	117.5	479.4
NOx	119.3	336.5

Source: CDPHE, Early Action Compact (EAC)

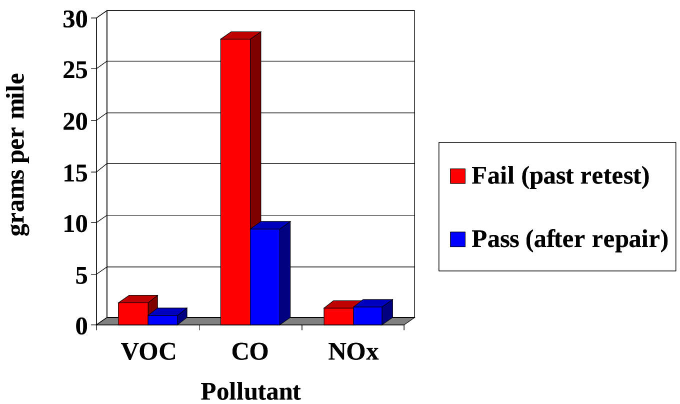
Repair Effectiveness

High emitting vehicles disproportionately contribute to mobile source emissions. Their repair is important in maintaining low overall mobile source inventories. Colorado inspection station data indicate that repairs to failing vehicles significantly reduce hydrocarbon emissions. Vehicles that failed their initial IM 240, and are later repaired, emit an average of 2.2 grams of hydrocarbons per mile. Upon passing a retest, these same vehicles emit an average of 1.0 gram of hydrocarbons per mile. This is a 57% reduction in the amount of hydrocarbons emitted by these vehicles.

Other emissions such as carbon monoxide, a weak ozone precursor, are similarly reduced. Motor vehicles that failed their initial IM 240 test, and are repaired, emit an average of 27.9 grams of carbon monoxide per mile. On a passing retest, these same vehicles emit an average of 9.4 grams of carbon monoxide per mile. This is a 66% reduction in the amount of carbon monoxide emitted by these vehicles. NOx emissions are not emphasized in Colorado's program and are basically unchanged. Adoption of tighter NOx emission cutpoints would result in greater NOx benefit.

The repair effectiveness results of Colorado's IM240 program are given in Figure 1.

Figure 1
2005 COLORADO IM240 TEST RESULTS
INITIAL FAILS VS FINAL PASSING TEST
ALL VEHICLES



On-Board Diagnostics
There are many different types of IM programs and IM tests. However, a simple cost-effective IM program is an on-board diagnostics (OBD) program, either as a stand-alone program for 1996 and newer model year vehicles, or one matched with an idle or other emissions test for 1995 and older vehicles. An OBD program can also be paired with an emissions test that measure a vehicle's emissions as well as examining their diagnostic codes. Examples of other emissions tests that may be paired with an OBD test are given in the attached appendix.

All 1996 and newer light duty vehicles are equipped with on-board diagnostics (OBD) technology. The intent of the OBD system is to monitor the vehicle's emissions control systems while the vehicle is in operation and detect potential problems as soon as they occur. Once a problem is detected, the system notifies the motorist by turning on a malfunction indicator light along with storing malfunction specific diagnostic information in the computer. The sensitivity of the system is programmed to detect a malfunction that may cause the vehicle's emissions to exceed 1.5 times its certification levels.

An OBD IM Program would require 1996 and newer model-year vehicles to undergo a periodic diagnostic check of all their stored trouble codes. If no malfunctions were identified the vehicle would pass. If malfunctions were identified, the vehicle would be required to be repaired. The following table identifies the IM benefit of an OBD-only program and an OBD program linked to an exhaust emissions test, in this case an IM240 test, for the Denver area fleet in 2007.

Table 2
OBD & OBD/IM240 Benefit
2007 Denver-Metro Fleet

	No I/M (gpm)		OBD only (gpm)	% Benefit		OBD w/IM240 (gpm)	% Benefit
HC	1.364		1.313	3.7		1.25	8.4
CO	13.627		12.832	5.8		11.959	12.2
NOx	1.392		1.334	4.2		1.315	5.5

Source: CDPHE, MOBILE 6 / 2007 Denver-metro fleet

II: Description of how to implement

An on-board diagnostics (OBD) program can be implemented as a contractor operated centralized IM program, or a decentralized inspection program, or decentralized inspection and repair program. State/local/or contractor staff would undertake program design, after authority for such a program is established through the state legislature and/or regulatory boards. Enforcement would be through state or local program enforcement staff. Registration denial would be the most effective way of maintaining program compliance.

III. Feasibility of option

An OBD program either with or without an emissions test is very feasible. Currently 32 states and the District of Columbia operate such a program, or will in the near future. Additionally, new innovative OBD features, such as self-standing, self-serve OBD kiosks, and loaner radio transponders are being implemented or are under development in Washington and California.

IV. Background data and assumptions used

Emission factors were generated by the U.S. EPA MOBILE 6b model. They reflect the Denver area fleet and transportation network for 2007. Repair effectiveness data is from the Colorado IM 240 program, and represents emission data derived from load-mode transient IM 240 testing. Inventories showing mobile source contribution are for the Denver metro area. Mobile sources' contribution is expected to be less in rural areas.

V. Any uncertainty associated with the option (Low, Medium, High)

Low. OBD Programs are proven strategies. A higher uncertainty exists for add-on elements such as implementation of self-standing, self-serve OBD kiosks, and loaner radio transponders. The greatest uncertainty is the integration of the data network with vehicle registration records and county clerk renewal processes. In states, such as Colorado, with existing IM Programs this is not an issue.

VI. Level of agreement within the workgroup for this mitigation option Good general agreement.

VII. Cross-over issues to other source groups

IM (inspection/maintenance) programs offer the ability to assist in controlling mobile source contributions to ozone formation, regional haze, air toxics, and global warming. There will be little cross-over issues with other groups. An IM program could affect gasoline vehicles used in oil and gas production, or other work covered by other groups, but generally there will be minimum cross-over.

As diesel vehicles and off-road vehicles are equipped with OBD features, they could conceivably be included in their own OBD programs. On-road diesels registered in the Front Range of Colorado currently participate in an opacity IM program.

Appendices

Significant Emissions Tests

On-Board Diagnostics

This technology is installed on 1996 and newer light-duty cars and trucks. It uses the vehicle's computer to identify potential emissions problems. If a problem exists, the system is required to warn the driver by displaying a warning light. Also, a "fault code" is simultaneously stored in memory identifying the problem area. Drivers are required to visit a test station periodically to have their vehicles "scanned" for fault codes This takes only a short amount of time. There is good accuracy in detecting potential problems with this test.

Idle Test
Initially used in New Jersey, Arizona and other states as early as 1974, emissions measurements take place while the engine is at the steady-state condition of idle. Over the years, minor changes were introduced and there are now six different idle test "types." Colorado first used this test in 1981 and still uses a modified version on heavy-duty vehicles, and older light-duty vehicles, in the Denver metropolitan program area. The major advantage of these tests is the relatively low equipment costs ranging from $15,000 to $20,000. The major drawback is a high level of false "passes" caused by newer technology on today's vehicles.

Acceleration Simulation Mode
In an attempt to increase accuracy, this newer class of steady-state test uses similar analytical equipment to the idle test, but also includes a dynamometer to "load" or "exercise" the vehicle at a constant speed. This test is designed primarily for states that are not in attainment for ozone.

A good example of the load applied to the vehicle during testing would be comparable to driving at a steady speed of 15 miles per hour on an eight percent grade hill, similar to the section of I-70 between the Morrison and Lookout Mountain exits, or at 25 miles per hour on a five percent grade hill, about half as steep as the previous example. The intent is to simulate an acceleration of the vehicle.

The two major positive elements of this test are the addition of nitrogen oxide emission measurements, and moderate equipment costs of $35,000 to $60,000.

Transient Tests
This class of test also utilizes a dynamometer but uses significantly more accurate analytical equipment and varies the vehicle speed during the inspection. The dynamometer load applied to the vehicle drive train is more similar to actual driving on a road. Test accuracy is the major positive element, with high equipment costs, often more than $100,000 being the major drawback. Because of the cost, transient tests usually are centralized due to economies of scale. The following major options are examples of transient tests.

IM 240
The IM 240 (Inspection and Maintenance, 240 seconds) is a shortened version of the Federal Test Procedure and is used in the Denver metropolitan program area. Vehicle speed is varied between 0 and 57 miles per hour. This test generally is considered to be the best predictor of the Federal Test Procedure.

IM 93
A shortened version of the IM 240, the IM 93 incorporates only the first 93 seconds. Top speed is approximately 36 miles per hour.

BAR 31
The BAR 31 (California Bureau of Automotive Repair, 31 seconds) is another loaded mode test, which has a maximum speed of 30 miles per hour and a driving time of 31 seconds, which can be repeated up to four times before failing the vehicle.

Other Predictive Options

Vehicle "Profiling"
Vehicle profiling runs in parallel with an existing inspection program. Using current inspection information, it is possible to predict whether a vehicle is likely to pass or fail based on the year, make and model. This increases the cost effectiveness of the inspection program by reducing the amount of resources needed for a full inspection test.

Low Emitter Profile
This method attempts to identify vehicles that are likely to be relatively "clean" vehicles or very low emitters. This can be done by analyzing current inspection data and predicting the probability that a certain year, make and model vehicle will pass the test.

High Emitter Profile
This method generally attempts to identify vehicles that are likely to be "dirty" or high emitters. Once identified, either through past inspection records of a specific vehicle, or because certain years, makes and models tend to be high polluters, targeted vehicles are subject to special treatment. Usually, this includes restricting the vehicle inspections to stations with higher quality control procedures and/or increasing the test frequency, e.g., substituting an annual inspection cycle for what would normally be a biennial cycle. Colorado does not use high emitter profiling in its inspection program.

Remote Sensing Clean Screen
Rather than trying to shorten or enhance a state's emission test, this technology attempts to "pre-screen" a vehicle as it drives by a remote sensing device placed on a roadside. If multiple readings indicate the car or truck is a low polluter, the vehicle owner is exempted for one test cycle from having to visit a traditional test station. The major benefit of this program is reduced inconvenience to owners of low polluting vehicles. A drawback is that some vehicles may be exempted that would normally fail the emissions test. However, by monitoring test conditions, this can be kept to a reasonable level that still meets air quality objectives. Additional issues are described in the body of this report.

Remote Sensing High Emitter Identification
As a vehicle drives by a remote sensing device, its emissions are measured. Vehicles with high enough emissions are required to come in for a confirmatory IM inspection.

Model Year Exemption
Another method of Low Emitter Profiling is exempting by model year. For instance, it is extremely unlikely that a new vehicle will fail an emissions test during the first few years from when it was manufactured. The case has been made that it is a waste of inspection resources and an owner's time to test those vehicles. Colorado exempts new cars from testing requirements for four model years.

Mitigation Option: Low Reid Vapor Pressure (RVP) Gasoline

I. Description of the mitigation option

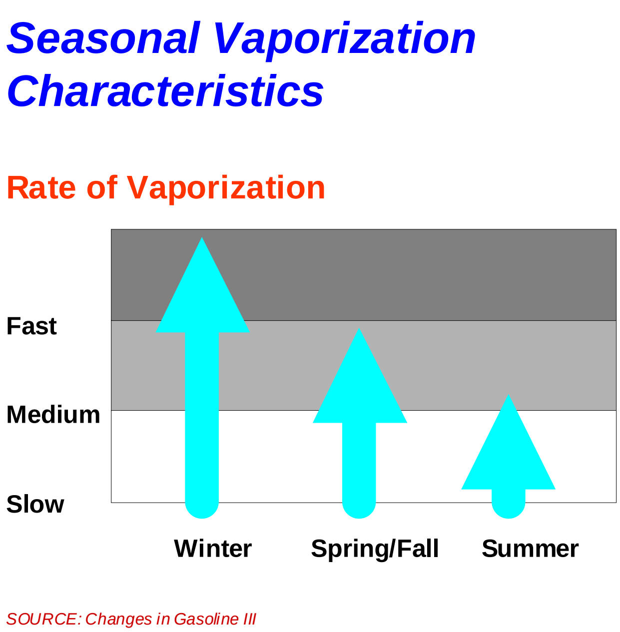
A major source of hydrocarbon emissions is the evaporative emissions produced by gasoline. Evaporative emissions occur during the refining process, through transportation and storage to the service station, and finally in refueling and operation of motor vehicles. The rate at which these emissions are produced is directly related to the fuel's volatility. The higher the volatility of the gasoline, the more volatile organic compounds (VOCs) are emitted at any given temperature.

One method to control gasoline evaporative emissions that contribute to ozone formation is to lower the volatility of gasoline, especially during the summer months. For most areas, summertime volatility is controlled by the U.S. Environmental Protection Agency (U.S. EPA). Under the Clean Air Act Amendments of 1990, the administrator of the U.S. EPA is charged with designating volatility standards for areas based on their air quality needs.

The U.S. EPA has set a gasoline volatility standard of 9.0 pounds per square inch (9.0 lbs.) for northern areas that meet the National Ambient Air Quality Standard for ozone. Air quality agencies with non-attainment areas may choose a different standard in their State Implementation Plan (SIP), or use the default standard set by the U.S. EPA.

Volatility outside the U.S. EPA controlled summer season (May 1st through September 15th) is generally controlled in most states by the American Society of Testing and Materials (ASTM) standards. These standards are set by national committees to reflect standards needed for good automotive operation and drivability.

Generally speaking, higher RVP is useful during the colder winter months to allow for easy cold weather starting and operation. Lower volatility is required during the warmer months, including summer, to prevent vehicle vapor locking and decreased drivability. The following chart shows this relationship.



Air Quality Benefits of Lower Volatility Gasoline

As part of its efforts to reduce summertime ozone, the Denver area examined the benefits of lower volatility of gasoline. This analysis, part of Colorado's Early Action Compact (EAC) found that reducing gasoline RVP from 9.0 pounds per square inch (lbs.) to 8.1 lbs. would reduce mobile source evaporative emissions by 10 tons of VOC per day. Lowering gasoline volatility still further to 7.8 lbs. was found to reduce evaporative emissions by 13 tons of VOC per day. This represents a 7.8% to 10.2% VOC reduction in mobile source emissions.

Table 1
2007 Denver Metro VOC Inventories
(tons per day)

Reid Vapor Pressure	Mobile Inventory	Mobile Source Benefit	Total Inventory
9.0 lbs.	128	0	489
8.1 lbs.	118	10	479
7.8 lbs.	115	13	476

Source: CDPHE, Early Action Compact (EAC)

Cost

In examining the use of lower volatility gasoline to reduce VOC emissions, it was estimated that the price of gasoline would be expected to increase by one or two cents per gallon. For the Denver area it was estimated that this would equate to $8,600 per ton for 8.1 lb. RVP gasoline and $13,300 per ton for 7.8 lb. RVP gasoline. Because of high ozone measurements in the summer of 2005, and the fact that Denver had been originally been designated as a 7.8 lb. RVP area by the EPA administrator in the early 1990s (though had a received a series of waivers from this requirement), the U.S. EPA reestablished the 7.8 lb. RVP requirement for the Denver area starting with the summer of 2004.

Outside of the Denver area, all of Colorado continues to have a 9.0 lb. RVP maximum for gasoline sold between June 1st and September 15th. Most of Utah (outside of Davis and Salt Lake counties) also has this summer maximum, as does New Mexico and most of Arizona (outside of part of Maricopa County). The following chart, taken from EPA's report, "Study of Unique Gasoline Fuel Blends (Boutique Fuels) Effects on Fuel Supply and Distribution and Potential Improvements," U.S. EPA 2001, diagrams the various summertime fuel specifications for different regions of the U.S.

Summertime Gasoline Requirements

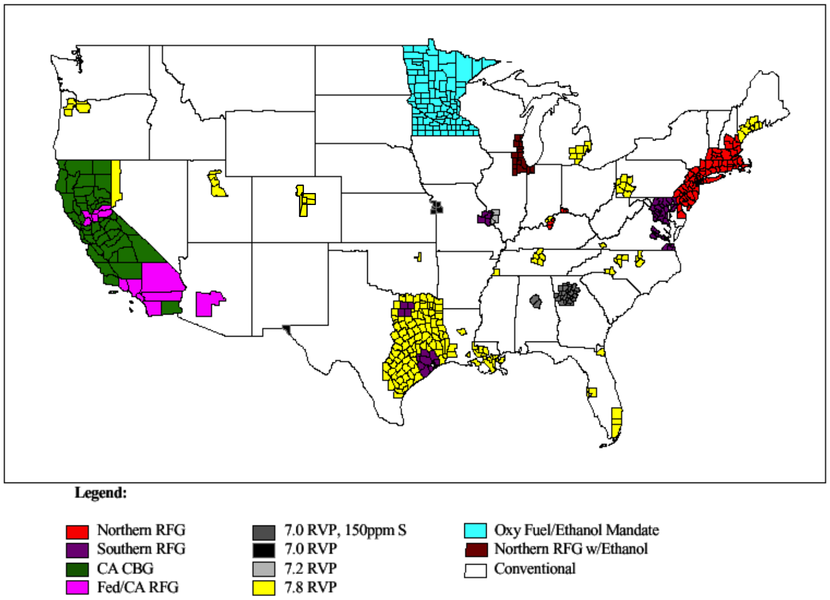


FIGURE II-1: Current Summer U.S. Gasoline Requirements

SOURCE: "Study of Unique Gasoline Fuel Blends ('Boutique Fuels'), Effects on Fuel Supply and Distribution and Potential Improvements" U.S. EPA Oct. 2001

II: Description of how to implement

Implementation of a low RVP program would be through State Implementation Plans. The various states would examine the options available, depending on air quality classification. If low RVP was required as a state program, the state would enforce the requirements. If it was an U.S. EPA program, the federal government would enforce.

III. Feasibility of option:

This option is fairly easy to develop and implement.

IV. Background data and assumptions used

A major assumption is that the Four Corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High) Low.

VI. Level of agreement within the workgroup for this mitigation option Good general agreement.

VII. Cross-over issues to other source groups

There does not seem to be much cross over.

Mitigation Option: Use of Reformulated Gasoline

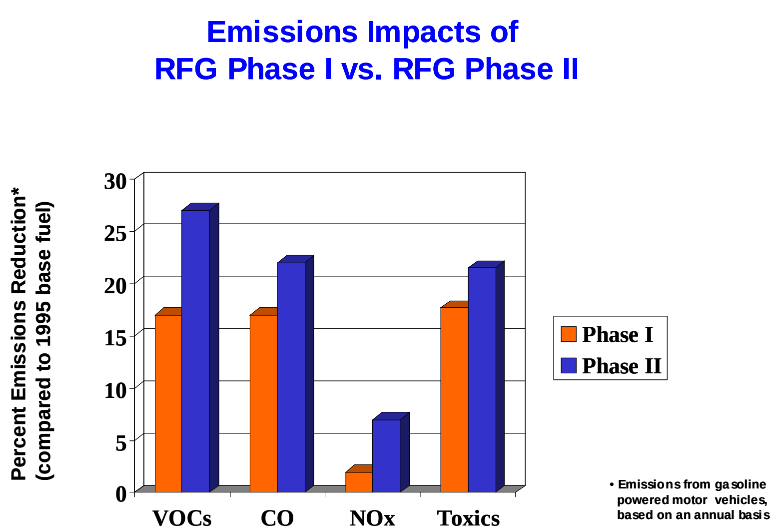
I. Description of the mitigation option

The use of reformulated gasoline (RFG) is an effective way of reducing ozone precursors from gasoline powered motor vehicles. Their use was first mandated in the nine most severe ozone nonattainment areas by the Clean Air Act Amendments of 1990. These areas included: Los Angeles, San Diego, Chicago, Houston, Milwaukee, Baltimore, Philadelphia, Hartford, and New York City. Others areas have since “opted” into the federal program. At last count, there are now 17 states and the District of Columbia that require its use. California implemented its own program beginning in 1992.

Reformulated gasoline is gasoline that has been reformulated to lower ozone precursors. While gasoline is generally formulated for the time of year or season, geographical location, altitude, and other conditions, reformulated gasoline is specifically formulated for emissions. Usually the distillation curve of the fuel (including Reid vapor pressure) is adjusted as well as other properties (light ends, olefin and aromatic content, etc.). By Clean Air Act requirement, an oxygenate, such as ethanol, is added. California reformulated gasoline goes an additional step in weighing hydrocarbon ozone forming reactivity in their performance-based standards.

Air Quality Benefits

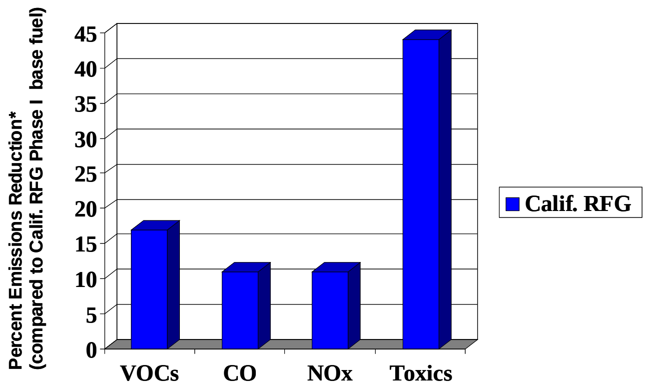
Under the original federal specifications, the use of federal Phase I reformulated gasoline (1995) was expected to reduce hydrocarbon and air toxic emissions by 15% compared to conventional gasoline. Phase II reformulated gasoline (2000) was mandated to reduce hydrocarbon and air toxic emissions by approximately 22%.



Source: US EPA,”Phase 11 Reformulated Gasoline: The Next Major Step Toward Cleaner Air”, Nov 1999, except for air toxics, EIA/DOE

California (CA) reformulated gasoline is even a more stringent formulation. The latest Phase 3 reformulated gasoline standards, based on the CaRFG3 predictive model, are 11% to 17% lower in HC, CO, and NOx emissions and 44% for air toxics compared to the original Phase 1 specifications introduced in 1992, itself a low ozone and air toxics formulation with caps on olefin and benzene content.

Emissions Impacts of Calif. RFG Phase II/III vs. Calif. RFG Phase I



Source: Chevron: "Gas and Air Quality: Reformulated Gasoline", Chevron

California Phase 2 reform (introduced in 1996) was estimated by the California Air Resources Board (CARB) to be twice as effective as Phase I federal reform of the same era. Phase 3 reformulated gasoline is very similar to CA Phase 2 in emissions, but does not use methyl tertiary-butyl ether (MTBE), an oxygenate found to contaminate groundwater if released during fuel spills or leaks.

Cost

Reformulated gasoline is more expensive than conventional gasoline to produce (though this is less so with the implementation of federal Tier II conventional gasoline requirements beginning in 2005). The U.S. EPA estimated that Phase I federal reformulated gasoline typically cost between three and five cents per gallon more to produce than conventional gasoline, with Phase II reform costing an additional one to two cents. CARB estimated California reformulated Phase 2 gasoline to be between five and fifteen cents per gallon more expensive than conventional gasoline.

Supply issues come into play with reformulated gasoline. While most refineries can easily make it, their facilities may not always be optimized to produce it. California reform is even more subject to these limitations.

Approximately 30% of all gasoline now sold in the United States is reformulated. The following chart, taken from EPA's report, "Study of Unique Gasoline Fuel Blends (Boutique Fuels) Effects on Fuel Supply and Distribution and Potential Improvements," U.S. EPA, 2001, diagrams the various reformulated gasoline program areas, as well as summertime fuel specifications for different regions of the U.S.

Summertime Gasoline Requirements

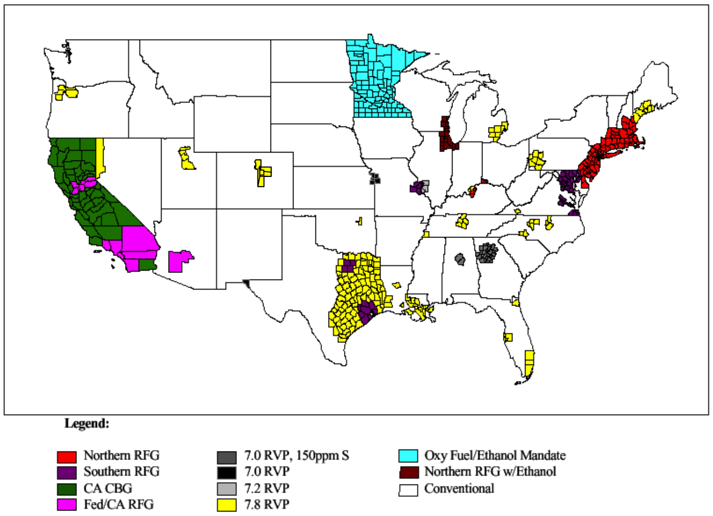


FIGURE II-1: Current Summer U.S. Gasoline Requirements

SOURCE: "Study of Unique Gasoline Fuel Blends ('Boutique Fuels'), Effects on Fuel Supply and Distribution and Potential Improvements" U.S. EPA Oct. 2001

II: Description of how to implement

Implementation of a RFG program would be through State Implementation Plans. The various states would examine the options available, depending on air quality classification. Typically a state will "opt" in to the federal reformulated gasoline program, with the federal government enforcing the program. If so desired the state may implement and enforce their own state RFG program. However, state programs must be identical to federal or California RFG programs.

III. Feasibility of option

This option is fairly easy to develop and implement.

IV. Background data and assumptions used

A major assumption is that the Four Corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. The use of reformulated gasoline would require that there be available supplies. A major refiner close to the four-corners area, Valero's McKee refinery located in the panhandle of Texas, already manufactures reformulated gasoline for Texas and other reformulated gasoline markets. The question is whether it and other refineries have the capacity, at a reasonable cost, to produce enough RFG for the Four Corners area.

VI. Level of agreement within the workgroup for this mitigation option

Good general agreement.

VII. Cross-over issues to other source groups

There does not seem to be much cross over.

Mitigation Option: Idle Ordinances

I. Description of the mitigation option

Motor vehicle idling is a source of preventable mobile source emissions. Recognizing that most vehicles do not need to idle, many cities have passed local ordinances banning excessive vehicle idling, specifically for heavy-duty vehicles such as trucks and buses. Voluntary idling programs may also be used, especially for gasoline powered light-duty vehicles.

Most city ordinances set the maximum idling time at two to five continuous minutes. Some have longer time limits. In Maricopa County, Arizona the time limit is five minutes. In Denver and Aurora, Colorado the time limit is 10 minutes in any one-hour period. Philadelphia has a minimum two minutes. The Houston/Galveston nonattainment area has a minimum of five minutes from April 1st through Oct. 31st. Salt Lake City permits up to 15 minutes of continuous idling.

Emissions Reductions

Idling ordinances generally target heavier diesel trucks and buses and particulate (PM) emissions. However, there is no reason to preclude light-duty gasoline vehicles. All internal combustion vehicles emit pollutants and green house gases. It is estimated that larger trucks and buses burn from one-half to one gallon of fuel per hour of idling (1,2), all of which produce unnecessary emissions. Light-duty gasoline vehicle fuel consumption may be half to a quarter of this.

According to Air Watch Northwest, a consortium of air quality management agencies in Washington state, Oregon, and British Columbia (www.airwatchnorthwest.com), cars at idle emit a comparable amount of pollution to when it is driven (3). This is especially true when a vehicle is started cold, before its catalytic converter is warm enough to become effective. Once warm, a catalyst will stay warm for quite some time, so shutting down an engine to conserve fuel and limit emissions will generally have little effect on catalytic effectiveness when the vehicle is restarted.

The following tables list the average emission for vehicles at idle. The first two are for passenger cars and light trucks. The third table lists emissions for heavy-duty trucks and buses. Data is from April 1998. The acronyms used in the charts are listed below. All data is from U.S. EPA, and may be obtained at: http://www.epa.gov/otaq/consumer/f98014.pdf

LDGV	Light-duty gas vehicle
LDGT	Light-duty gas truck
HDGV	Heavy-duty gas vehicle
LDDV	Light-duty diesel vehicle
LDDT	Light-duty diesel truck
HDDV	Heavy-duty diesel vehicle
MC	Misc

U.S. EPA Estimated Idle Emissions
for Passenger Cars and Light Trucks

Summer Conditions (75 degrees F., 9.0 psi Rvp gasoline)

Pollutant	Units	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
VOC	g/hr	16.1	24.1	35.8	3.53	4.63	12.5	19.4
	g/min	0.269	0.401	0.597	0.059	0.077	0.208	0.324
CO	g/hr	229	339	738	9.97	11.2	94.0	435
	g/min	3.82	5.65	12.3	0.166	0.187	1.57	7.26
NOx	g/hr	4.72	5.71	10.2	6.50	6.67	55.0	1.69
	g/min	0.079	0.095	0.170	0.108	0.111	0.917	0.028

Winter Conditions (30 degrees F., 13.0 psi Rvp gasoline)

Pollutant	Units	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
VOC	g/hr	21.1	30.7	44.6	3.63	4.79	12.6	20.1
	g/min	0.352	0.512	0.734	0.061	0.080	0.211	0.335
CO	g/hr	371	487	682	10.1	11.5	94.6	388
	g/min	6.19	8.12	11.4	0.168	0.191	1.58	6.47
NOx	g/hr	6.16	7.47	11.8	6.66	6.89	56.7	2.51
	g/min	0.103	0.125	0.196	0.111	0.115	0.945	0.042

U.S. EPA Estimated Idle Emissions
for Heavy –Duty Trucks and Buses

Engine Size	Emissions
Light/Medium HDDVs (8501-33,000 GVW)	2.62 g/hr (0.044 g/min)
Heavy HDDVs (33,001+ GVW)	2.57 g/hr (0.043 g/min)
HDD buses (all buses, urban and inter-city travel)	2.52 g/hr (0.042 g/min)
Average of all heavy-duty diesel engines	2.59 g/hr (0.043 g/min)

These average idle emissions may be compared to average vehicle emissions by comparing the first two tables with the table listed below. This data may be obtained at:
http://www.epa.gov/otaq/consumer/f00013.htm

U.S. EPA Emissions Facts
Average Annual Emissions and Fuel Consumption
for Passenger Cars and Light Trucks

Component	Car Emission Rate Fuel Consumption	Light Truck Emission Rate Fuel Consumption
HC	2.80 g/mi	3.51 g/mi
CO	20.9 g/mi	27.7 g/mi
NOx	1.39 g/mi	0.81 g/mi
CO2	0.915 lbs/mi	1.15 lbs/mi
Gasoline	0.0465 gal/mi	0.0581 gal/mi

As can be seen by a comparison of the above tables, for volatile organic compounds (VOCs), it will take eight minutes of idling to equal one mile of driving for an average automobile during the summer. For carbon monoxide (CO) this is approximately five and a half minutes, and, for nitrogen oxides (NOx) this is approximately seventeen and a half minutes.

Particulate Emissions

One reason to adopt idling ordinances or some voluntary program to reduce idling is the exposure to particulate emissions. One of the principle sources of particulate matter (PM) exposure is from diesel vehicles. This is of utmost importance when it comes to school-age children and their exposure to diesel school bus particulate and air toxic emissions. On average, children and adults may be exposed to excessive levels of PM from idling diesel trucks and buses. As the above table points out, an average heavy-duty diesel truck or bus will produce approximately 2.6 grams of particulates per hour. It should be noted that federal health-based PM standards are measured in the micrograms (not grams) range. The short term PM standard for PM_{10} is $150ug/m^3$ for a 24-hour average.

Technologies Used to Reduce Truck Idling

A number of strategies can be used to assist vehicles, mostly trucks and buses, from needing to idle while maintaining heating and cooling capacity. For larger trucks and buses, stand-alone direct-fired heating devices are available that cost from $1000 to $2000. Automatic engine idling devices may also be used that continue air conditioning when the engine is turned off at a cost of $1000 to $2000. Most expensively, small power generating auxiliary power units may be used, each costing from $5000 to $7000 (2).

At truck stops, fleet locations, and other stationary parking facilities, truck-stop electrification may be utilized. “Shore power” is provided directly to the parked truck, linking it to the power grid for all its electrical needs. This is estimated to cost $2500 per truck space and another $2500 per truck to modify so that it can receive the electricity (2).

References:
(1). U.S. EPA
(2). Philadelphia Diesel Difference Working Group
(3). Air Watch Northwest

II: Description of how to implement

Generally local government may adopt ordinances limiting vehicle idling, principally heavy-duty diesel truck or bus idling. School districts can modify their procedures to prevent excessive school bus idling. Trucking fleets, including oil and gas extraction fleets can also implement updated policies for their drivers.

Local air planning agencies, state, or local government can also implement voluntary programs, aimed at both light-duty gasoline vehicles as well as heavy-duty diesel vehicles. Voluntary programs can be established relatively easily and in a minimal amount of time. Infrastructure to promote auxiliary power for trucks to use at truck stops, distribution centers (think Walmart), etc., would take more time and money to accomplish.

III. Feasibility of option

This is a very feasible option. Idling ordinances and voluntary idling reduction programs have been established for a number of years in many locations.

IV. Background data and assumptions used

Emission estimates are generally those published by the U.S. EPA.

V. Any uncertainty associated with the option (Low, Medium, High)
Low. Idling ordinances and voluntary idling reduction programs are proven strategies.

VI. Level of agreement within the workgroup for this mitigation option
Good general agreement.

VII. Cross-over issues to other source groups
There will be little cross-over issues with other groups, except for fleets, such as involved in oil and gas extraction.

Mitigation Option: School Bus Retrofit

I. Description of the mitigation option
One of the most significant sources of particulate and air toxic exposures that young school-age children are exposed to are diesel school bus emissions. Older diesel school buses contribute a greater proportion of particulate (PM), as well as nitrogen oxide (NOx) and hydrocarbon (HC) emissions, compared to current buses built to the newest emission certification standards.

While the newest school bus emissions standards have just been implemented, school buses have long lives, permitting older higher emitting school buses to continue to expose children to high levels of diesel exhaust and to contribute to summertime ozone precursors. Reducing emissions from these buses will result in emission reductions that will last for years.

One method of reducing emissions from these older school buses is through school bus retrofit programs. Retrofit programs achieve their air quality benefit by improving the emissions characteristics of the existing school bus. Improvements may range from re-powering school buses with new replacement engines, or adding better emission control equipment, to using cleaner sources of fuel.

Emissions Reductions

PM Emissions
It is estimated by the U.S. EPA that oxidation catalytic converters retrofitted to buses reduce PM emissions by 20% to 30%, at a cost of $1000 to $2000 per bus(1). Retrofitting with a particulate trap reduces particulate matter by 60% to 90%, at a cost of $5000 to $10,000 per bus(1).

The use of ultra-low sulfur diesel fuel (required since 2006) allows these components to be added without the sulfur in diesel fuel contaminating the retrofitted equipment with a consequential loss in efficiency or damage. Ultra-low sulfur diesel fuel (maximum of 15 ppm sulfur content) is by itself expected to reduce particulate emissions by 5% to 9% (1).

Natural gas fueled school buses, if done correctly, can reduce particulate emissions by 70% to 90% at an additional cost of approximately $30,000 per bus(1). Replacement engines could reduce particulate emissions by 95% (2) as well as substantially reducing HC and NOx emissions.

Hydrocarbon and Carbon Monoxide Emissions
For ozone precursors, oxidation catalytic converters can reduce HC emissions by up to 50%. Carbon monoxide emissions may be reduced by up to 40%(2). Particulate traps will give some benefit, but are principally designed to lower particulate emissions.

The use of biodiesel fuel does reduce HC emissions, though its use will tend to increase NOx emissions (B20 up to 2%, B100 up to 10%(1)). Depending on the technology used, natural gas fueled school buses substantially lower NMHC. The U.S. EPA estimates NMHC emissions are reduced by 60%(1). NOx emissions, especially if lean-burn natural gas engines are used, may be lowered by a comparable amount. New technology replacement engines, built under the newest emissions certification standards would have substantial HC+NOx emission reductions.

The U.S. EPA has a technology Options Chart that they developed for their Clean School Bus USA Program. It lists the various technology options, their costs, and their benefits. It can be accessed at: http://www.epa.gov/cleanschoolbus/technology.htm.

Sources:
U.S. EPA Clean School Bus USA
Illinois Clean School Bus Program

Funding
There are various sources of funding for school bus retrofit programs. The U.S. EPA has annually funded retrofit programs. In 2007 they received seven million dollars under continuing resolution (H.J.R. 20) to fund projects nationwide. Eligible applicants that may apply for these funds include: state and local government, federally recognized Indian tribes, and non-profit organizations. Other sources of funding and grants include federal Congestion Mitigation and Air Quality (CMAQ) Program funds.

II: Description of how to implement
Local air planning agencies, state, or local government can implement these programs. Generally, they are funded through grants or other funding sources. They can be established relatively easily, with the needed outside infrastructure currently in place.

III. Feasibility of option
This is a very feasible option. School bus retrofit programs are operating throughout the United States.

IV. Background data and assumptions used
Emission reductions are generally those published by the U.S. EPA.

V. Any uncertainty associated with the option (Low, Medium, High)
Low. School Bus Retrofit Programs are proven strategies

VI. Level of agreement within the workgroup for this mitigation option
Good general agreement.

VII. Cross-over issues to other source groups
There will be little cross-over issues with other groups.

Mitigation Option: Subsidy Program for Cleaner Residential Fuels

I. Description of the mitigation option

Many families and individuals are forced by circumstances (economic, lack of availability, insufficient fuel delivery infrastructure, etc.) to use less than desirable fuels for cooking and heating. Many of these fuels, such as wood burning, emit high levels of toxic, or harmful, emissions, and carbon monoxide, hydrocarbon and organic compounds that are ozone precursors.

An option to reduce emissions that contribute to increased VOC, PM, CO, and air toxics is to promote the use of less polluting home heating and cooking fuels, especially electricity, propane, and natural gas in place of wood, coal, and kerosene. If wood is to continue to be used for home heating, at least a high efficiency EPA Phase II certified stove should be used.

Subsidizing Increased Cost of Fuel

Subsidizing the use of propane, natural gas, or electricity may allow low-income families to utilize these fuels in place of wood burning or other fuel sources, such as coal. Subsidy could be pegged to the economic need of the family, much like other welfare programs.

Home Heating

Replacing a traditional, non-certified wood stove with an oil furnace will reduce particulate (PM) emissions by over 99%, from 18.5 g/hr to 0.07 g/hr. Replacement with a natural gas furnace would reduce PM emissions even further to 0.04 g/hr (2).

The use of oil or gas furnaces in place of wood stoves would also have a substantial effect on carbon monoxide and emissions of hydrocarbons and other organic compounds, many of which have high ozone reactivities, as well as being fairly toxic gases. Encouraging the use of substituting electric or gas heat for cooking would similarly give a comparable emissions benefit.

New York State Environmental Protection Bureau estimates that a typical high efficiency (90%) gas or oil forced hot air furnace costs approximately $2690. This compares to a new EPA certified, catalytic equipped wood stove at approximately $2425, with a 72% efficiency rating (2).

Cleaner Wood Stoves

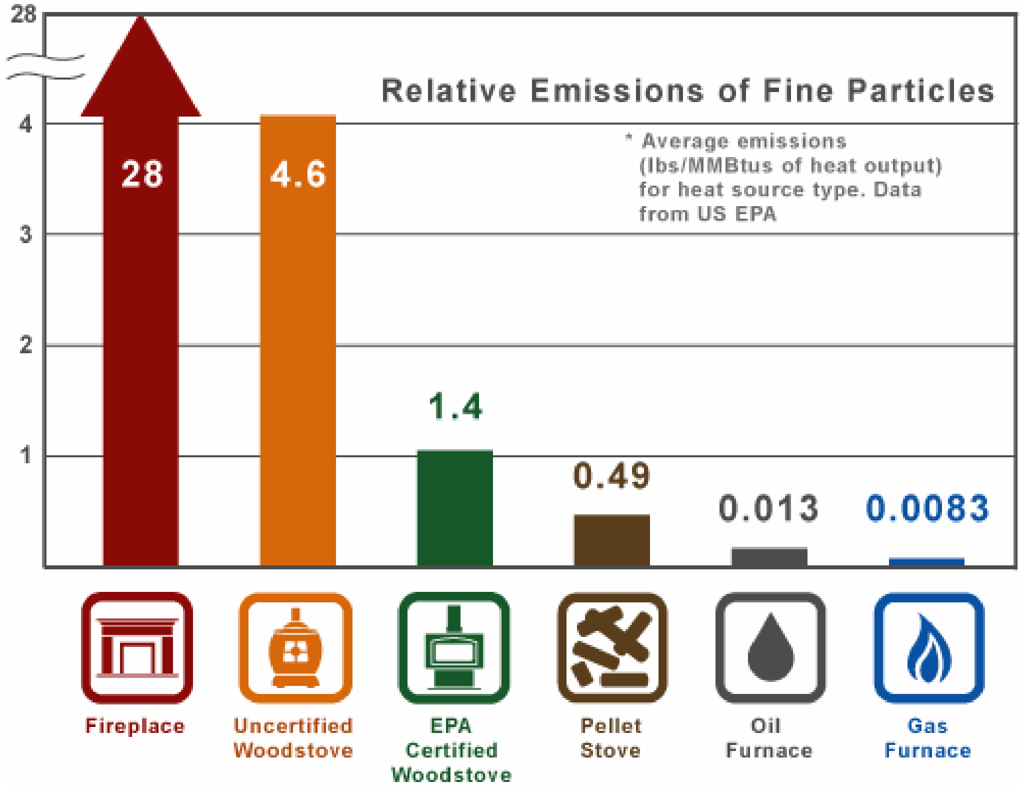
If a woodstove were used, it should be a new EPA certified one that would be expected to reduce fine particulate emission by 70% compared to an older non-controlled stove. Polycyclic aromatic hydrocarbons would be expected to go down from 0.36g/hr to 0.14 - 0.15 g/hr for EPA Phase I certified stoves to less than that for EPA Phase II certified stoves (2).

Nationwide, wood burning accounts for nine percent of home heating needs. However, it accounts for 45% of all particulate emissions from home heating (2). U.S. EPA Phase II standards are 7.5 g/hr PM for non-catalytic equipped stoves, and 4.1 g/hr PM for catalytic equipped ones (1,2). These standards are designed to reduce woodstove emissions by 60% to 80%(1).

In replacing an older uncontrolled stove with a new EPA certified stove, it is important to use an outside source of air for the heater box for combustion proposes. This prevents the stove from depleting a room's oxygen content, as well as preventing emissions from entering the house. Stoves should also have catalytic converters to ensure the lowest emissions. Common models currently may produce from 35,000 to 100,000 BTU, and are able to heat rooms from 400 to 2000, or more, square feet(3). US EPA has a website at: http://www.epa.gov/woodstoves, where more information may be obtained.

Chart One
Relative Emissions of Fine Particulates
(Grams per Hour)

U.S. EPA Chart



Source: U.S. EPA

Reference Sources:
(1). U.S. EPA
(2). New York State Environmental Protection Bureau
(3). Chimney Sweep, Inc.

II: Description of how to implement

This program may be organized much like Low Income Energy Assistance programs. A means test or other criteria could be established to prioritize available funding.

Funding this program, or set of programs, may include tax incentives, or other methods, such as voluntary grants from the natural gas extraction industry, mineral surtaxes, or drilling and permit fees. Enforcement penalties could also be used.

III. Feasibility of option

The program is very feasible. It would not only reduce emissions that could aggravate ambient ozone, PM, and CO, but would reduce toxic exposure to inhabitants of the house and nearby homes.

IV. Background data and assumptions used
It is assumed that there is a sufficient population that would benefit from an assistance program.

V. Any uncertainty associated with the option (Low, Medium, High)
Medium. Such a program, unless funded voluntarily as a public outreach program by industry, may require additional statutory authority, requiring legislative action, as well as well as regulatory development and adoption.

VI. Level of agreement within the workgroup for this mitigation option
Good general agreement. The option was agreed upon by the workgroup without dissent.

VII. Cross-over issues to other source groups
There are no cross-over issues identified at the present time.

Mitigation Option: Stage One Vapor Recovery

I. Description of the mitigation option:

Mandatory use of stage-one vapor recover systems will reduce evaporative emissions from service stations.

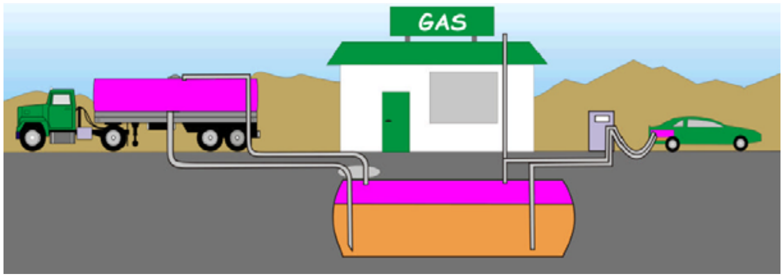
Refueling of underground service station tanks is a major source of evaporative hydrocarbon emissions. VOCs are released as the underground storage tank is refilled, when gasoline vapors in the tank's headspace are displaced. Sources estimate that 10-15 liquid gallons of gasoline are released from vapors displaced from the headspaces of various tanks, each time a gasoline transport truck fully unloads its products (1,2,3). Unless captured through a vapor recovery system, such as Stage I, these emissions will be released directly into the atmosphere.

In many areas, Stage I vapor recovery systems are required to control VOC emissions within the gasoline distribution system, from the refinery to the retail gasoline station. In the Denver metropolitan area, for instance, Stage I is required to control VOC releases that contribute to summertime ozone formation. Fire codes require the use of Stage I at service stations in other areas. But in many places their use is not required, and stations may, or may not, be using any vapor recovery stations, even if they are equipped with them. Stations that are equipped with Stage I vapor recovery systems may not be operating them. Other older stations may not even be equipped with vapor recovery systems.

The following diagram shows how Stage I works. In this diagram the fuel delivery truck unloads its product into the bottom of an underground storage tank through the refueling pipe. A second pipe then draws the vapors being displaced as the underground storage tank is being filling, and discharges them into the now emptying fuel delivery trucks compartment. The empty truck then returns to the refinery or terminal and releases the captured vapors into the refinery's or terminal's vapor recovery system, where they are condensed back into liquid gasoline and reused.

The same illustration also shows how Stage II vapor recovery systems work, by using the same principle, capturing the VOCs produced as an automobile is refueled. As the automobile is refueled, vapors displaced by the car's gasoline tank are drawn back through the dispensing pump back into the underground storage tank by a second refueling tube. There, they either condense into gasoline within the tank, or are directed into the refueling tanker truck, through the station's Stage I system when the underground tank is next refueled by the tank truck.

Stage I Vapor Recovery



Source: Calif. EPA, Nov.18, 2004

References:

"What You Should Know About Vapor Recovery", Michigan Department of Environmental Quality.
"Keeping It Clean: Making Safe and Spill-Free Motor Fuel Deliveries," Petroleum Equipment Institute, December 1992.
"New Hampshire Stage I/II Vapor Recovery Program", New Hampshire Department of Environmental Services.

Air Quality Benefits of Stage One Vapor Recovery
As part of its effort to reduce summertime ozone, the Denver metropolitan area requires the use of Stage 1 at all service stations. It is estimated that because of Stage I requirements, that perhaps 13.2 million pounds of VOCs (18.1 tons per day) are prevented from being emitted into the air*. Air toxics are also reduced.

Stage I vapor recovery systems are efficient. Up to 95%(1) of underground storage-tank refueling vapors are captured. Stage I is also cost effective. Vapors from the underground storage tanks are collected in the now empty tanker truck's compartments and taken back to the refinery or terminal, where they are condensed and reused. At $3.00 a gallon for gasoline seen in the summer of 2007, this equates to $2.1 million dollars worth of gasoline saved annually.

(1), Hensel, John, and Mike Mondloch,"Stage One Vapor Control In Minnesota", Minnesota Pollution Control Agency.

* Based on emission factors from the state of New Hampshire (11 lbs. VOC produced per 1000 gallons of gasoline vapors displaced), and 1.2 billon gallons of gasoline delivered to service stations in the Denver metropolitan area each year.

Cost

Many stations, while not operating their Stage I equipment are equipped with it. Others would have to be retrofitted. The Minnesota Pollution Control Agency estimates that retrofitting a station will cost up to $15,000 per station, with a more typical cost of approximately $10,000 per station. This is a very reasonable cost for the emissions benefits that can be derived.

II: Description of how to implement:
Implementation of Stage I vapor recovery would be through State Implementation Plans. A state could also adopt such as a program as a state-only program if not part of a SIP. The state would enforce the requirements.

III. Feasibility of option:
This option is fairly easy to develop and implement.

IV. Background data and assumptions used
A major assumption is that the four corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High):
Low.

VI. Level of agreement within the workgroup for this mitigation option:
Good general agreement.

VII. Cross-over issues to other source groups:
There does not seem to be much cross over.

Mitigation Option: Stage Two Vapor Recovery and Vehicle On-board Refueling Vapor Recovery Systems

I. Description of the mitigation option:
Mandatory use of Stage-II vapor-recover systems as well as programs designed to maintain vehicle's on-board refueling vapor recovery systems reduce evaporative emissions created during automobile refueling.

Automotive refueling is a major source of evaporative hydrocarbon emissions. As a vehicle's gas tank is filled gasoline vapors in the tank's headspace are displaced. It is estimated that when filling an empty 18-gallon fuel tank, 0.06 pounds of VOCs can be released (1,2), if such vapors are not captured by either a service station's Stage II vapor-recovery system, or for newer vehicles, the vehicle's on-board refueling vapor recovery system (this assumes that 30% of the vehicle's gasoline tank's headspace is composed of gasoline vapors and 70% by air) (2).

In a Stage II system, as an automobile is refueled, vapors displaced in the car's gasoline tank are drawn back through the dispensing pump back into the underground storage tank by a second refueling tube. There, they either condense into gasoline within the tank, or are directed into the refueling tanker truck, through the station's Stage I system when the underground tank is next refueled by the tank truck. The following illustration diagrams this.

Stage II Vapor Recovery System

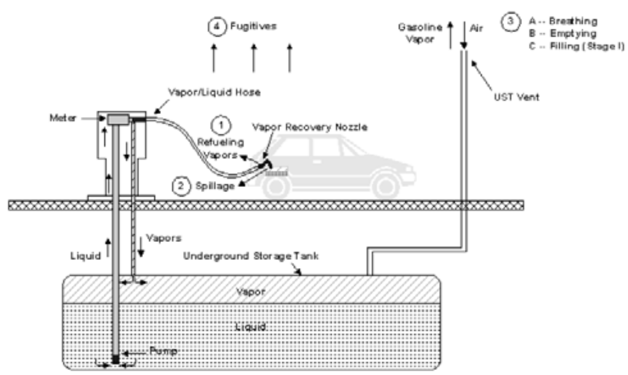
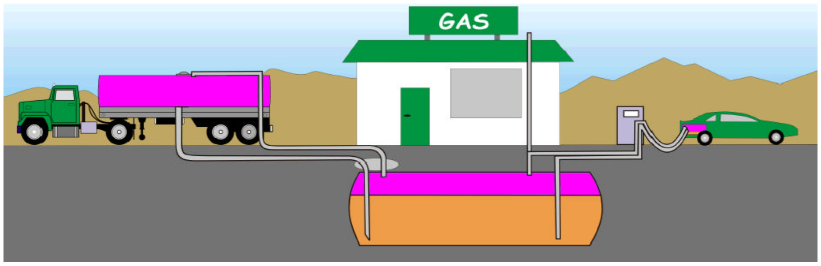


Figure 2. Controlled Stage II Process Operations with vapor recovery system.

Source: "Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.
http://www.ct.gov/dep/lib/dep/air/stageII/stage2issuepaper.pdf

Another illustration also shows how Stage II works in conjunction with Stage I. Vapors from the automobile's gasoline tank are routed back into the headspace of the station's underground storage tank. In this diagram the fuel delivery truck unloads its product into the bottom of an underground storage tank through the refueling pipe. A second pipe then draws the vapors being displaced as the underground storage tank is being filling, and discharges them into the now emptying fuel delivery trucks compartment. The empty truck then returns to the refinery or terminal and releases the captured vapors into the refinery's or terminal's vapor recovery system, where they are condensed back into liquid gasoline and reused.

Stage I & II Vapor Recovery Systems



Source: Calif. EPA, Nov.18, 2004

References:
"New Hampshire Stage I/II Vapor Recovery Program", New Hampshire Department of Environmental Services.
"Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.

Air Quality Benefits of Stage II Vapor Recovery Systems
As part of its effort to reduce summertime ozone, many metropolitan areas across the nation with ozone concerns have adopted the use of Stage II vapor recovery systems at service stations. Stage II vapor recovery systems can be efficient. Depending on the frequency of inspection and equipment maintenance, up to 95%(1) of refueling vapors may be captured. In reducing VOCs, many air toxics, such as benzene and 1,3 butadiene are also reduced.

Modeling conducted by Mobiles Sources Program, Air Pollution Control Division, of the Colorado Department of Public Health and Environment, indicate that implementation of a Stage II vapor recovery program in the Denver Metropolitan area would reduce overall mobile source VOCs by 5.5% in the year 2007, and by 3.8% in the year 2012, when more vehicles are equipped with on-board vapor recovery systems.

On-board Refueling Vapor Recovery (ORVR) systems
On-board refueling vapor recovery (ORVR) systems work by routing escaping vapors from the fuel tank; through a charcoal canister that absorbs VOCs. The trapped VOCs are then pulled from the canister into the engine where they are burnt. ORVR systems have become standard equipment on light-duty automobiles beginning in 1998, and light duty trucks (trucks 1-2 starting in 2001, and trucks 3-4 in 2004).

As stated before, as the fleet penetration of on-board refueling vapor recovery systems increases, the emissions benefit from Stage II decreases somewhat. Currently, in the Denver metropolitan area, 54% of all gasoline motor vehicles now are equipped with on-board vapor recovery systems. As more of the fleet is equipped with on-board refueling vapor recovery systems, the effectiveness of Stage II is reduced. However, working together, they will both reduce refueling losses in the near to medium term, as shown in CDPHE's MOBILE6 modeling results. It should be pointed out that as ORVR systems deteriorate, refueling losses increase. At some point in the future, it may be necessary to implement some sort of inspection program to find and have fixed broken ORVR systems, maintaining the air quality benefits of these systems.

The U.S. EPA in their report "Stage II Vapor Recovery Issue Paper (August 12, 2004) includes a diagram (Figure 5, page 16 - shown below), of the refueling emissions trends for a hypothetical State. From inputs contributed by the American Petroleum Institute, this illustration shows four different scenarios; Stage II vapor recovery controls only (the blue line); on-board refueling vapor recovery only (the red line); Stage II vapor recovery controls with on-board refueling vapor recovery, where the ORVR interferes with the Stage II controls (the green line); and 4) Stage II vapor recovery controls and on-board refueling vapor recovery, where the ORVR does not interfere with the Stage II controls (the black line). The chart diagrams the years from 2005 through 2035 (1).

As seen in this diagram, a state with an existing Stage II vapor recovery program with an 85% effectiveness (blue line) will have a fraction of the refueling VOC emissions as a state that does not (the red line) in the year 2005. As more vehicles are equipped with ORVR systems, this advantage decreases, with at some point before 2015, the benefits of both control measures being equal. The blue line increases over time because of the increase in vehicle miles travels and does not include the effect of ORVR. However, before this time (2015), Stage II vapor recovery programs will give large benefits.

The other two scenarios shown represent decreasing VOCs over time with both control measures. There has been some research showing that Stage II can potentially interfere with on-board refueling vapor recovery systems. This is represented by the green line, where there is some increase in emissions as a result. However, all new Stage II systems certified by the state of California must show no interference with the ORVR. Using these approved systems, total VOCs are reduced for both Stage II and ORVR (the black line), where until 2025 there is a noticeable improvement having both systems.

Refueling Emissions Trends for Four Scenerios:

1) Stage II controls only (Blue Line), 2) On-board Refueling Vapor Recovery (ORVR) only (Red Line), 3) Stage II & ORVR with compatibility issues (Green Line), 4) Stage II & ORVR with no compatibility issues (Black Line)

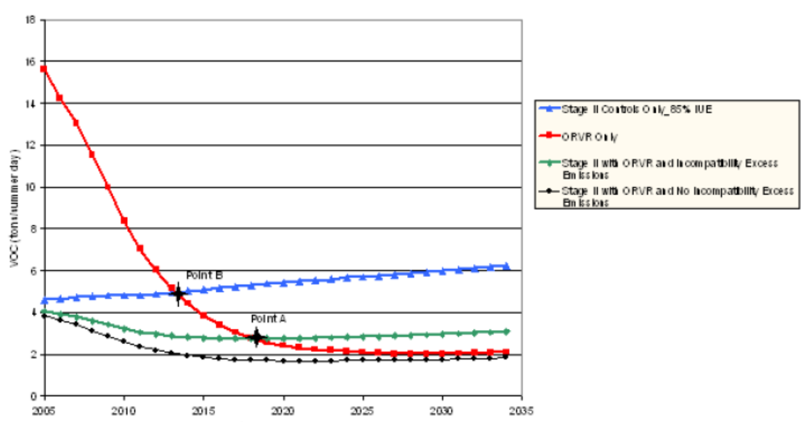


Figure 5. General emissions trends expected for refueling emissions in future calendar years for a hypothetical State (based on API studies).

Source: "Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.
http://www.ct.gov/dep/lib/dep/air/stageII/stage2issuepaper.pdf

(1) "Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.

<u>Cost</u>
There are costs to retrofit service stations with the necessary plumbing and equipment. In some cases this will be a major renovation to the station. Additionally, there will be on-going costs associated with operating and maintaining the Stage II vapor recovery system and equipment.

The state of New Hampshire, which has an operational Stage II vapor recovery program, estimates that the cost of Stage II installation at between $18,000 and $30,000 per station, depending on the station (1). They estimate on-going annual maintenance costs to be $1000 to $4000 per station yearly (1). Stage II requirements affect any station in that state that sells or has throughput of more than 420,000 gallons of gasoline annually (1).

(1) Environmental Fact Sheet, "New Hampshire's Gasoline Vapor Recovery Program - Protecting the Air We Breathe" New Hampshire Department of Environmental Services, 2004.

<u>II: Description of how to implement:</u>
Implementation of Stage II vapor recovery would be through State Implementation Plans. The state would enforce the requirements.

<u>III. Feasibility of option:</u>
This option is moderately hard to develop and implement. Gasoline service stations that are already plumbed for Stage II, and do not have to tear up concrete to put in vapor recovery plumbing are relatively easy to upgrade. Stations that need extensive work to install will be more difficult. Industry will not be supportive of this option.

<u>IV. Background data and assumptions used</u>
A major assumption is that the four corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

<u>V. Any uncertainty associated with the option (Low, Medium, High):</u>
Low.

<u>VI. Level of agreement within the workgroup for this mitigation option:</u>
Good general agreement.

<u>VII. Cross-over issues to other source groups:</u>
There does not seem to be much cross over.

OTHER SOURCES: PUBLIC COMMENTS

Other Sources Public Comments

Comment	Mitigation Option
Dear Task Force Representative: I work for the Ute Mountain Tribe's Environmental Programs Department. We are about to partner with the EPA and the USGS to monitor radionuclides in the air and water around White Mesa, Utah where there is the only operating uranium mill in the nation. They are increasing production dramatically at the mill. We have significant concerns about radioactive dust blowing around out there. Any assistance that you or your staff could provide, funding if possible, would be a great thing. In the end we will have a publicly available, peer-reviewed report published by USGS and EPA. This could be a very important piece of the 4 corners air quality puzzle for you. My contact information is: Scott Clow, Water Quality Specialist, Ute Mountain Ute Tribe, PO Box 448, Towaoc, CO 81334, (970) 564-5431, scute@fone.net Thanks for considering this. Sincerely, Scott	
The last mitigation option makes me think that it is time to start considering regulating wood and coal burning stoves all-together. We have a tendency in the 4 corners to believe that we are small-fry, but continued urbanization is delivering us many big-city problems. In all, oil, gas and power plants tend to overshadow the cumulative impacts of residential activities. Our county governments should consider mitigation options accordingly.	
It is not enough to address the larger sources of air pollution in the Four Corners area. The efforts of this task force must also address the cumulative effects of the smaller sources.	
This is a great option. The Farmington/Aztec/Bloomfield area is an urban corridor, and the Durango/Bayfield area is quickly becoming so as well. We could easily reduce emissions and highway miles traveled if we were to expand upon park-and-ride systems (I believe I saw an ad for one between Ignacio and Durango) and also municipal transit.	Public Buy-in through Local Organizations to push for transportation alternatives and ordinances
Public outreach is great (often people are unaware of the health problems due to burning), but it may not reach the few and highly resistant people who burn regularly (both commercial and residential). As a resident, I would like to be able to call the sheriff and have enforcement that is effective (a fine, for example).	Develop Public Education and Outreach Campaign for Open Burning
The worst offending vehicles pass because their owners know how to beat the system on testing. Just enforce laws about taking cars off the road that visually are not in compliance. Add a tax based on engine size or exempt smaller engines and low weight vehicles.	Automobile Emissions Inspection Program
IM Programs will only work if all areas in that region are included. If they are not then owners of car will find ways to get around the program. Most of the owners that would do this are the owners of the cars that are the problem. Another way to make sure that your program is effective is to make sure that there is a assistance program for owners that can not afford to get their car emissions fixed.	Automobile Emissions Inspection Program

Comment	Mitigation Option
The IM programs will only be effective for our purposes if they are implemented in all areas. Also, the emissions programs for cars need stricter standards, thus making it economically infeasible to own larger engine, less efficient vehicles. There will always be those who find their way around the laws. However, if those laws are stricter, actually enforced, and applied throughout the Four Corners area then more problem vehicles will be taken off the road.	Automobile Emissions Inspection Program
On a voluntary basis, people could "adopt/subsidize" other vehicles that are not meeting emissions specs. Maybe this adoption could be tax deductible or a tax credit. How do we address the high emitting, newer vehicles (ie large trucks/cars)from the LEV (low emission vehicles)? Maybe a taxing structure would help both reduce the demand for new higher polluting vehicles, and help get high polluting older (the old "beater") vehicles off the road by helping to pay for their improvement/replacement.	Automobile Emissions Inspection Program
I would like City (and County if possible) ordinances to restrict idling. A rule that everyone follows will make it easier to get everyone on board the "no idling" plan. Public outreach also has to follow to teach people why idling causes problems and how "no idling" make make a difference. Signage at parking areas/unloading areas boat ramps, water filling stations/hydrants, the post office, grocery stores and other parking lots and etc. can remind drivers to turn off their engines.	Idle Ordinances
School bus retrofit--Let's do it! Then add public outreach to encourage more students to ride the bus, and we reduce emissions because the parents are not lined up in their cars to pick up/drop off their kids at school.	School Bus Retrofit
Though indirectly related to this topic, homes need to be upgraded weatherized and insulated so that we decrease the amount of fuel needed. Public outreach might help teach people how to build a clean fire. And people are burning trash in their wood stoves (similar to open burning). Coal is often used for heating and is particularly high in emissions, and seems to be equal to open burning.	Subsidy Program for Cleaner Residential Fuels

Energy Efficiency, Renewable Energy and Conservation

Energy Efficiency, Renewable Energy and Conservation: Preface

The Task Force identified a need for an Energy Efficiency, Renewable Energy, and Conservation (EEREC) mitigation option section for the Task Force report. Since this category had cross over among the groups, each group contributed to this section of the report. The Other Sources and Power Plants Work Groups met together at the November 8, 2006 Task Force meeting and briefly at the February 8, 2007 meeting to discuss EEREC as a topic. Louise Martinez, Bureau Chief of Energy Efficiency Programs with the New Mexico Energy, Minerals, and Natural Resources Department, gave a presentation on New Mexico Clean Energy Programs in the work group breakout session. New Mexico has a comprehensive set of renewable energy incentives to attract new projects and developers. The Four Corners area has a very strong solar energy resource and potential for energy efficiency improvements which both could offer environmental and health benefits.

Energy use is increasing in the Four Corners Area and in the U.S. as a whole. New generation will be required to meet additional energy demands. The work group on EEREC discussed that we could use the proactive NM position on clean energy as an example of a model to help write mitigation options for developing clean energy in the 4 Corners. Options focused on not only industry but also consumer behaviors. Three general areas were identified for options. Twenty-one mitigation options were brainstormed for the EEREC section; 18 were drafted.

Efficiency is important because efficiency is getting more out of each bit of energy we use. The result can be a direct benefit by reducing emissions from power plants or other sources and getting work done for less money. Efficiency has an indirect benefit by reducing the demand for additional energy production.

The work group brainstormed and drafted several options relating to efficiency. Options written included the following: Improved efficiency of home & industrial lighting; home audits for energy efficiency, as well as green building and energy efficiency incentives. An option was also written to improve county & city planning efforts. One option on power generation energy efficiency at existing power plants was written and included in the Existing Power Plants mitigation option section.

Renewable energy is important because it can benefit air quality by complementing and offsetting existing fossil fuel energy use and generation with clean energy sources. The work groups wrote options on better utilizing the solar resources in the Four Corners; expanding renewable portfolio standards to the Four Corners area municipalities and power cooperatives; creating/improving net-metering agreements with the electric utilities; and several others. A few policy options were written concerning importing and using only clean energy locally. One option tying together renewable energy and energy efficiency was written on “The Use and Credit of Energy Efficiency and Renewable Energy in the Environmental Permitting Process.” An option discussing the viability of biomass as an energy source to mitigate air pollution was also drafted in addition to an option for a bioenergy center.

Conservation, or using less energy, is also important because it reduces air pollution. Burning fossil fuels directly or using electricity generated by fossil fuel combustion results in increased air pollutants. Decreasing energy consumption correlates to decreased emissions. Options focusing on conservation centered around energy use. Options that could improve conservation efforts and reduce emissions included smart metering, direct load control, time based pricing, and residential bill structure changes. The work group discussed the need for more education of the public & industry on these issues. An option for an “Outreach Campaign for Conservation & Wise Use of Energy” was drafted. The San Juan VISTAS program, a voluntary emissions reduction program emphasizing energy efficiency, was discussed as a possible model for all sectors of industry and the community to work together to improve air quality through cost effective strategies in the Four Corners area.

ENERGY EFFICIENCY

Mitigation Option: Advanced Metering

I. Description of the mitigation option

Overview

Advanced Metering is the integration of electronic communication into metering technology to facilitate two-way communication between the utility and the customer equipment. Increasing electric energy prices and a growing awareness of the need to reduce the environmental impact of electric energy consumption are directing the industry, legislators and regulators to turn to Advanced Metering technologies for solutions. Strategic deployment of Advanced Metering Systems will facilitate or enable sustainable and cost-effective Energy Efficiency (EE) and Demand Response (DR) programs while at the same time providing a platform for cost-reducing innovations in the areas of customer service, reliability, operations and business practices.

Partly due to the time lag between when energy is consumed and when the consumption is billed, and partly because there is no tangible commodity to associate with their monthly electric bill, most end-use customers have a difficult time relating their monthly electric bill with their daily energy use patterns. Consequently, a critical component of effective and sustainable EE and DR programs is the ability to provide energy use information to customers in an understandable, timely and useable manner. An Advanced Metering System with its two-way communication system provides an infrastructure for sending and receiving timely energy use and pricing information and, if desired, load control signals directly to customers and end-use equipment.

Advanced Metering Systems supports both EE and DR programs. The primary objective of EE programs is to reduce the total amount of energy used annually by consumers. (DR focuses on shifting energy use to off peak hours and does not necessarily result in energy conservation). EE programs, therefore, are typically focused on consumer education, the use of more energy efficient equipment and other measures such as building improvements to reduce energy losses and waste.

Environmental Benefits - Advanced metering provides indirect benefit to the environment by providing real-time tools to enable the customer to make informed decisions around energy use and conservation. Energy conservation displaces a portion of electric generation and can lead to lower emissions of carbon dioxide (CO_2), nitrogen oxides (NO_x), sulfur dioxide (SO_2, and particulate matter (PM-10). In addition, reduced operation of generating plants means less water use and a reduction in the amount of natural resources (fossil fuels) being extracted from the earth. It can also help prevent or delay the need for building new power plants or other new energy infrastructure.

Economic- Direct operational benefits may result, including reduced monthly metering read costs; reduced meter read to billing time; reduced costs related to unaccounted for energy, energy diversion and energy theft; and reduced time to restore service following an outage.

Other benefits may include:

Increased customer satisfaction due to real time access to energy use information and other meter data by customer service personnel

Increased customer satisfaction due to the availability of accurate real time outage information and reduced outage times

The ability to apply innovative rate structures

Trade-offs - Capital costs to install Advanced Metering Systems can be more costly than conventional meters. Several years may be required for payback of Advanced Metering Systems.

II. Description of how to implement

Mandatory or Voluntary: Could be either voluntary or mandatory. Utilities have demonstrated that voluntary dynamic pricing programs can generate demand response and energy conservation. However, these programs tend to attract only modest levels of participation, in large part because they are narrowly targeted and passively marketed.

The public utility commission is the most appropriate entity to implement.

A differing opinion comment was received on this option during the Task Force Report Public Comment Period: "Advanced metering for home owners will not work. It will only enrich the electric companies who will use the data to set rates higher when people need the energy. An alternative is rolling blackouts on house ACs like that used in the Houston, TX area." See the public comments received for EEREC in the appendix to this section.

III. Feasibility of the option

A. Technical: Good feasibility. Programs have been applied and demonstrated at utilities across the country. Advanced metering systems are commercially available.

B. Environmental: Medium feasibility. Prices and advanced metering systems can be used to modify customer behavior to use less electricity within individual homes and businesses during peak hours, but metering by itself does not save energy. Instead, metering should be viewed as a technology that enables optimized performance and energy efficiency, and provides the information necessary for customers to make more-informed decisions regarding their energy use.

Should energy conservation take place, air emissions, water and fossil fuel use can be reduced through generation displacement. Additionally, EE and DR programs may allow utilities to hold off adding new generation assets, thereby, improving opportunities for employment of more advanced, demonstrated and cost-effective clean coal and renewable energy technology.

C. Economics: Advanced metering systems must be designed, managed, and maintained to cost-effectively meet site specific needs. Applications analysis must consider both initial costs (i.e. purchase and installation) and on-going operations costs (e.g., data analysis, system maintenance, and resulting corrective actions).

IV. Background data and assumptions used

Gillingham, K., R. Newell, and K. Palmer, The Effectiveness and Cost of Energy Efficiency Programs, Resources Publication, Fall 2004, pgs. 22-25, www.rff.org/Documents

Federal Energy Regulatory Commission, Assessment of Demand Response and Advanced Metering, Staff Report, Dockett No. AD-06-2-000

Assumption: Regulatory rate structures that allow for decoupling profits from sales to remove disincentives to conservation.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. Voluntary programs do not guarantee energy conservation and emissions reductions.

VI. Level of agreement within the work group for this mitigation option

Good. This option write-up stems from a discussion at the February 7, 2007 meeting of the Power Plant Working Group.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

Other Sources Group- Renewable Energy, Energy Efficiency and Conservation Mitigation Options

Mitigation Option: Cogeneration/Combined Heat and Power

I. Description of the mitigation option

Combined Heat and Power (CHP) is the sequential or simultaneous generation of multiple forms of useful energy (usually mechanical and thermal) in a single, integrated system. CHP systems consist of a number of individual components – prime mover (heat engine), generator, heat recovery, and electrical interconnection – configured into an integrated whole. The type of equipment that drives the overall system (i.e., the prime mover) typically identifies the CHP system. Prime movers presented the CHP systems discussed herein include reciprocating engines, combustion or gas turbines, steam turbines, and microturbines.

These prime movers are capable of burning a variety of fuels, including natural gas, coal, oil, and alternative fuels to produce shaft power or mechanical energy. Although mechanical energy from the prime mover is most often used to drive a generator to produce electricity, it can also be used to drive rotating equipment such as compressors, pumps, and fans. Thermal energy from the system can be used in direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling. When considering both thermal and electrical processes together, CHP typically requires only ¾ the primary energy separate heat and power systems require. This reduced primary fuel consumption is key to the environmental benefits of CHP, since burning the same fuel more efficiently means fewer emissions for the same level of output.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of CHP should be "voluntary" since the economics, operational aspects and emissions must be customized to the design objectives of the facility.
B. Indicate the most appropriate agency(ies) to implement**:** Since the option is voluntary and based upon the business decision of the entity proposing the facility, there is agency that would be in a position to mandate requiring CHP to be used. However, there could be a number of state agencies involved in permitting a CHP facility, including the state Air Quality Division, to issue air quality related construction and operating permits as appropriate.

III. Feasibility of the option

A. CHP Technologies

1. Gas turbines: are typically available in sizes ranging from 500 kW to 250 MW and can operate on a variety of fuels such as natural gas. Most gas turbines typically operate on gaseous fuel with liquid fuel as a back up. Gas turbines can be used in a variety of configurations including (1) simple cycle operation with a single gas turbine producing power only, (2) combined heat and power (CHP) operation with a single gas turbine coupled and a heat recovery exchanger and (3) combined cycle operation in which high pressure steam is generated from recovered exhaust heat and used to produce additional power using a steam turbine. Some combined cycles systems extract steam at an intermediate pressure for use and are combined cycle CHP systems. Many industrial and institutional facilities have successfully used gas turbines in CHP mode to generate power and thermal energy on-site. Gas turbines are well suited for CHP because their high-temperature exhaust can be used to generate process steam. Much of the gas turbine-based CHP capacity currently existing in the United States consists of large combined-cycle CHP systems that maximize power production for sale to the grid.

2. Microturbines, which are small electricity generators that can burn a wide variety of fuels including natural gas, sour gases (high sulfur, low Btu content), and liquid fuels such as gasoline, kerosene, and diesel fuel/distillate heating oil. Microturbines use the fuel to create high-speed rotation that turns an electrical generator to produce electricity. In CHP operation, a heat exchanger referred to as the exhaust gas heat exchanger, transfers thermal energy from the

microturbine exhaust to a hot water system. Exhaust heat can be used for a number of different applications including potable water heating, absorption chillers and desiccant dehumidification equipment, space heating, process heating, and other building uses. Microturbines entered field-testing in 1997 and the first units began commercial service in 2000. Available and models under development typically range in sizes from 30 kW to 350 kW.

3. There are various types of reciprocating engines that can be used in CHP applications. Spark ignition (SI) and compression ignition (CI) are the most common types of reciprocating engines used in CHP-related projects. SI engines use spark plugs with a high-intensity spark of timed duration to ignite a compressed fuel-air mixture within the cylinder. SI engines are available in sizes up to 5 MW. Natural gas is the preferred fuel in electric generation and CHP applications of SI. Diesel engines, also called CI engines, are among the most efficient simple-cycle power generation options in the market. These engines operate on diesel fuel or heavy oil. Dual fuel engines, which are diesel compression ignition engines predominantly fueled by natural gas with a small amount of diesel pilot fuel, are also used. Higher speed diesel engines (1,200 rpm) are available up to 4 MW in size, while lower speed diesel engines (60 - 275 rpm) can be as large as 65 MW. Reciprocating engines start quickly, follow load well, have good part-load efficiencies, and generally have high reliabilities. In many instances, multiple reciprocating engine units can be used to enhance plant capacity and availability. Reciprocating engines are well suited for applications that require hot water or low-pressure steam.

4. Steam turbines that generate electricity from the heat (steam) produced in a boiler for CHP application. The energy produced in the boiler is transferred to the turbine through high-pressure steam that in turn powers the turbine and generator. This separation of functions enables steam turbines to operate with a variety of fuels including natural gas. The capacity of commercially available steam turbine typically ranges between 50 kW to over 250 MW. Although steam turbines are competitively priced compared to other prime movers, the costs of a complete boiler/steam turbine CHP system is relatively high on a per kW basis. This is because steam turbines are typically sized with low power to heat (P/H) ratios, and have high capital costs associated with the fuel and steam handling systems and the custom nature of most installations. Thus the ideal applications of steam turbine-based CHP systems include medium- and large-scale industrial or institutional facilities with high thermal loads and where solid or waste fuels are readily available for boiler use.

B. Environmental: CHP technologies offer significantly lower emissions rates per unit of energy generated compared to separate heat and power systems. The primary pollutants from gas turbines are oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs) (unburned, non-methane hydrocarbons). Other pollutants such as oxides of sulfur (SO_x) and particulate matter (PM) are primarily dependent on the fuel used. Similarly emissions of carbon dioxide are also dependent on the fuel used. Many gas turbines burning gaseous fuels (mainly natural gas) feature lean premixed burners (also called dry low-NO_x burners) that produce NO_x emissions ranging between 0.3 lbs/MWh to 2.5 lbs/MWh with no post combustion emissions control. Typically commercially available gas turbines have CO emissions rates ranging between 0.4 lbs/MWh – 0.9 lbs/MWh. Selective catalytic reduction (SCR) or catalytic combustion can further help to reduce NO_x emissions by 80 percent to 90 percent from the gas turbine exhaust and carbon-monoxide oxidation catalysts can help to reduce CO by approximately 90 percent. Many gas turbines sited in locales with stringent emission regulations use SCR after-treatment to achieve extremely low NO_x emissions.

Microturbines have the potential for low emissions. All microturbines operating on gaseous fuels feature lean premixed (dry low NO_x, or DLN) combustor technology. The primary pollutants from microturbines include NO_x, CO, and unburned hydrocarbons. They also produce a negligible amount of SO_2.

Microturbines are designed to achieve low emissions at full load and emissions are often higher when operating at part load. Typical NO_x emissions for microturbine systems range between 0.5 lbs/MWh and 0.8 lbs/MWh. Additional NO_x emissions removal from catalytic combustion is microturbines is unlikely to be pursued in the near term because of the dry low NO_x technology and the low turbine inlet temperature. CO emissions rates for microturbines typically range between 0.3 lbs/MWh and 1.5 lbs/MWh.

Exhaust emissions are the primary environmental concern with reciprocating engines. The primary pollutants from reciprocating engines are NO_x, CO, and VOCs. Other pollutants such as SO_x and PM are primarily dependent on the fuel used. The sulfur content of the fuel determines emissions of sulfur compounds, primarily SO_2. NO_x emissions from reciprocating engines typically range between 1.5 lbs/MWh to 44 lbs/MWh without any exhaust treatment. Use of an oxidation catalyst or a three way conversion process (non-selective catalytic reductions) could help to lower the emissions of NO_x, CO and VOCs by 80 percent to 90 percent. Lean burn engines also achieve lower emissions rates than rich burn engines.

Emissions from steam turbines depend on the fuel used in the boiler or other steam sources, boiler furnace combustion section design, operation, and exhaust cleanup systems. Boiler emissions include NO_x, SO_x, PM, and CO. The emissions rates in steam turbine depend largely on the type of fuel used in the boiler. Typical boiler emissions rates for NO_x with any postcombustion treatment range between 0.2 lbs/MWh and 1.24 lbs/mmBtu for coal, 0.22 lbs/mmBtu to 0.49 lbs/mmBtu for wood, 0.15 lbs/mmBtu to 0.37 lbs/mmBtu for fuel oil, and 0.03lbs/mmBtu – 0.28 lbs/mmBtu for natural gas. Uncontrolled CO emissions rates range between 0.02 lbs/mmBtu to 0.7 lbs/mmBtu for coal, approximately 0.06 lbs/mmBtu for wood, 0.03 lbs/mmBtu for fuel oil and 0.08 lbs/mmBtu for natural gas. A variety of commercially available combustion and post-combustion NO_x reduction techniques exist with selective catalytic reductions achieving reductions as high as 90 percent. SO_2 emissions from steam turbine depend largely on the sulfur content of the fuel used in the combustion process. SO_2 composes about 95% of the emitted sulfur and the remaining 5 percent are emitted as sulfur tri-oxide (SO_3). Flue gas desulphurization (FGD) is the most commonly used post-combustion SO_2 removal technology and is applicable to a broad range of different uses. FGD can provide up to 95 percent SO_2 removal.

While not considered a pollutant in the ordinary sense of directly affecting health, CO_2 emissions do result from the use the fossil fuel based CHP technologies. The amount of CO2 emitted in any of the CHP technologies discussed above depends on the fuel carbon content and the system efficiency. The fuel carbon content of natural gas is 34 lbs carbon/mmBtu; oil is 48 lbs of carbon/mmBtu and ash-free coal is 66 lbs of carbon/mmBtu.

<u>C. Economic:</u> The total plant cost or installed cost for most CHP technologies consists of the total equipment cost plus installation labor and materials, engineering, project management, and financial carrying costs during the construction period. The cost of the basic technology package plus the costs for added systems needed for the particular application comprise the total equipment cost. Total installed costs for gas turbines, microturbines, reciprocating engines, and steam turbines are comparable. The total installed cost for typical gas turbines ranges from $785/kW to $1,780/kW while total installed costs for typical microturbines in grid-interconnected CHP applications may range anywhere from $1,339/kW to $2,516/kW. Commercially available natural gas spark-ignited engine gensets have total installed costs of $920/kW to $1,515/kW, and steam turbines have total installed costs ranging from $349/kW to $918/kW.

Non-fuel operation and maintenance (O&M) costs typically include routine inspections, scheduled overhauls, preventive maintenance, and operating labor. O&M costs are comparable for gas turbines, gas engine gensets, steam turbines and fuel cells, and only a fraction higher for microturbines. Total O&M costs range from $4.2/MWh to $9.6/MWh for typical gas turbines, from $9.3/MWh to $18.4/MWh for commercially available gas engine gensets and are typically less than $4/MWh for steam turbines. Based on manufacturers offer service contracts for specialized maintenance, the O&M costs for microturbines appear to be around $10/MWh.

IV. Background data and assumptions used

A. CHP offers energy and environmental benefits over electric-only and thermal-only systems in both central and distributed power generation applications. CHP systems have the potential for a wide range of applications and the higher efficiencies result in lower emissions than separate heat and power generation system. The advantages of CHP broadly include the following:

- The simultaneous production of useful thermal and electrical energy in CHP systems lead to increased fuel efficiency.
- CHP units can be strategically located at the point of energy use. Such onsite generation avoids the transmission and distribution losses associated with electricity purchased via the grid from central stations.
- CHP is versatile and can be coupled with existing and planned technologies for many different applications in the industrial, commercial, and residential sectors.

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option

Although a general discussion of this option has not occurred between the working group members, most of the members do not have technical experience working with CHP facilities.

Source of Information: Catalogue of CHP Technologies, U.S. Environmental Protection Agency, Combined Heat and Power Partnership

Mitigation Option: Green Building Incentives

I. Description of the mitigation option

This option involves the promotion of the Leadership in Energy Efficiency and Design certification LEED through state sponsored incentives. The LEED Green Building Rating System™ is the nationally accepted benchmark for the design, construction, and operation of high performance green buildings. LEED gives building owners and operators the tools they need to have an immediate and measurable impact on their buildings' performance. LEED promotes a whole-building approach to sustainability by recognizing performance in five key areas of human and environmental health: sustainable site development, water savings, energy efficiency, materials selection, and indoor environmental quality.

The cost of LEED certification depends upon: the level of certification sought, the particular project demographics and characteristics, the availability of grants for achieving certification, the LEED experience of the Design Team, the LEED experience of the estimator, the stage in the design at which the Client makes the decision to seek certification (the earlier the better), and the Client's perception of the value and benefits of a more attractive building environment for their occupants. While the factors above may seem numerous, they are quantifiable, they can be priced, and they can be managed.

Certain aspects are realized at no additional cost due to the high level construction performance that today's contractors insist upon as standard practice. Clearly, the higher the certification level, the more it is required to accept the points that have significant additional cost impact. The strategy therefore is to firstly seek the points that have no financial impact, followed by either the insignificant premium costs or the insignificant additional costs. The expensive points are usually only sought when applying for Gold or Platinum certification.

II. Description of how to implement

A. Mandatory or voluntary: Because of concerns associated with the additional costs of certification, this program should be voluntary in scope. Yet, it should be mandatory for all new government buildings to be modeled after some of the options and foundations that this program is built upon, without necessarily reaching for LEED certification.

B. Indicate the most appropriate agency(ies) to implement: Colorado/NM Offices of Energy Management and Conservations,

III. Feasibility of the option

A. Technical: There are only two buildings with the highest LEED certification nation wide, although this certification is technically feasible. There are thousands of buildings build or retrofitted throughout the nation that initially use the guidelines and practices laid out in the LEED certification although they are not LEED certified.

B. Environmental: The environmental benefits of energy efficiency programs are very well documented.

C. Economic: This certification does increase the cost of construction through additional project management and supply demands. Although there are additional costs, the LEED certification does show economic benefits over the life of the building.

IV. Background data and assumptions used

V. Any uncertainty associated with the option: Medium

VI. Level of agreement within the Work Group for this option: TBD

Mitigation Option: Improved Efficiency of Home and Industrial Lighting

I. Description of the Mitigation Option

Utilizing compact fluorescent lights can result in significant energy savings when compared to traditional incandescent lights. Improved lighting efficiency in homes and in commercial/industrial business applications throughout the Four Corners States has tremendous potential to reduce energy consumption, save money, and reduce the amount of fuel burned in coal fired power plants. Burning less coal would result in fewer air pollution emissions.

One quote commonly used in news articles states "If every home in the U.S. switched one light bulb with an ENERGY STAR, we would save enough energy to light more than 2.5 million homes for a year and prevent greenhouse gases equivalent to the emissions of nearly 800,000 cars" (U.S. EPA, 2006).

Background:
Artificial lighting accounts for approximately 15 percent of the energy use in the average American home (U.S. DOE, 2006). Lighting consumes about 20 percent of all electricity used in the U.S. The nationwide lighting figure is potentially as high as 21-34 percent when the air conditioning needed to offset the heat produced by conventional lighting is considered (Rocky Mountain Institute, 2006).

Benefits: Energy Star qualified compact fluorescent light bulbs (CFLs) have many benefits including:

CFLs use 70 to 75 percent less energy than standard light bulbs (General Electric Company, 2006) with minimal loss of function. If the cost of the bulbs, lower energy use, and longer operating life are considered, a consumer can save approximately $52 over eight years for each CFL bulb that replaces a standard light bulb (Rocky Mountain Institute, 2004).

More than 90 percent of the energy used by incandescent lights is given off as heat, which creates the need run air conditioners to compensate for the heat generation and increases energy use (Rocky Mountain Institute, 2006). CFLs generate 70 percent less heat, reducing the need to cool interior air (US EPA, 2006).

CFLs commonly have an operating life of 6,000-15,000 hours compared to 750-1,500 hours for the average incandescent light (USDOE, 2006). CFLs last from 6-15 times longer.

At 4 mg of mercury per light, CFLs have the lowest mercury content of all lights containing mercury. All fluorescent lights contain mercury, incandescent lights do not. Use of CFLs results in a net reduction in mercury because coal power is such a large source of atmospheric mercury. The 70 percent lower energy consumption from CFLs compared to incandescent lights, results in a 36 percent mercury reduction into the atmosphere by coal-burning power plants. With proper recycling, the mercury released by CFLs decreases up to 76 percent compared to incandescent lights (US EPA, 2002; Rocky Mountain Institute, 2004).

Reduction in coal produced energy consumption would also result in a decrease of SOx, NOx, CO2, and other air pollution emissions. It can be demonstrated that running a 100-watt light bulb 24 hours a day for one year requires about 714 pounds of coal burned in a coal power generator. CFLs that use 70 to 75 percent less energy, would also translate from less power used, less coal burned, and fewer emissions. "Every CFL can prevent more than 450 pounds of emissions from a power plant over its lifetime" (U.S. EPA, 2006)

II. Description of how to implement

It has been determined that lack of awareness about the environmental benefits and energy/cost savings of CFL lights is the single largest barrier to their widespread use. CFL light replacement and education programs already exist in the U.S. and in other countries. Components of these programs were used in preparing this mitigation option.

Options could include any or all of the following:

States adopt the goal of delivering one free CFL bulb to every household in Colorado, New Mexico, Arizona, and Utah. Utilities, businesses, communities, and volunteers work together to deliver bulbs and information on the cost savings and environmental benefit of using CFLs.
Within the Four Corners States, adopt a campaign which includes regional advertising, information brochures, and marketing to promote awareness about the energy efficiency and environmental benefits of switching to CFL lights.
Provide light retailers with point-of-sale displays illustrating CFL cost savings, energy savings, proper CFL bulb selection, environmental benefits etc.
Offer State tax incentives for businesses/corporations that build or retrofit facilities using advanced lighting technologies including CFLs.

Voluntary or mandatory – The responsibility to develop a CFL light distribution and education program should be headed by the State governments of the Four Corners region. Coal power plants, utility companies, and other energy-related industry could voluntarily contribute to the purchase of CFL lights for distribution in households, and also contribute to educational awareness programs.

B. Indicate the most appropriate agency(ies) to implement – Colorado Department of Public Health and the Environment, New Mexico Environment Department, Utah Division of Air Quality, Arizona Department of Environmental Quality, DOE and EPA should take lead program roles. Certain aspects, such as purchasing lights for distribution, could be cooperatively funded by the Four Corners region coal-burning power plants, or State governments.

III. Feasibility of the Option

Technical: CFL technology is well developed and commonly available. In fact, large manufacturers of CFLs such as the General Electric Company and large distributors such as Walmart have embarked on major campaigns to promote and distribute CFL lights primarily for the "green" energy savings they represent (Fishman, 2006).

Environmental: Proven 70 percent reduction in energy consumption compared to traditional incandescent lights. Energy efficiency translates to reduction in air pollution emissions from coal-fired power plants. Lowest mercury content of all fluorescent lights, lower overall mercury emissions due to less coal based energy consumed.

Economic: Proven cost savings to consumers due to high energy efficiency and longer bulb life. If a 75 watt bulb is replaced by an 18 watt CFL bulb which is operated four hours a day, the estimated eight year savings is $36 - $52 (U.S. EPA, 2006, Rocky Mountain Institute, 2004). This calculation accounts for the higher purchase cost of CFLs.

IV. Background Data and Assumptions Used

(1) Fishman, Charles, 2006. How Many Lightbulbs Does it Take to Change the World? One. And You're Looking at It. Fast Company Magazine, New York, NY.
www.fastcompany.com/magazine/108/open_lightbulbs.html

(2) General Electric Company, 2006. Ecomagination – For the Home: Compact Fluorescent Lighting. http://ge.ecomagination.com

(3) U.S. DOE, 2006. Energy Efficiency and Renewable Energy Consumers Guide: Lighting. http://www.eere.energy.gov/consumer/your_home/lighting

(4) U.S. EPA, 2006. Compact Fluorescent Light Bulbs: ENERGY STAR. Http://www.energystar.gov/

(5) U.S. EPA, 2002. Fact Sheet: Mercury in Compact Fluorescent Lamps (CFLs). www.nema.org/lamprecycle/epafactsheet-cfl.pdf

(6) Rocky Mountain Institute, 2006. Efficient Commercial/Industrial Lighting. http://www.rmi.org/sitepages/pid297.php

(7) Rocky Mountain Institute, 2004. Home Energy Briefs, #2 Lighting. http://www.rmi.org/

V. Any Uncertainty Associated With the Option

Low – both for feasibility and energy savings and environmental benefit through emissions reductions.

VI. Level of Agreement within the Work Group for this Mitigation Option TBD.

VII. Cross-over Issues to the Other Source Groups None at this time.

Mitigation Option: Volunteer Home Audits for Energy Efficiency

I. Description of the mitigation option

This option involves the development and implementation of a program or project that will engage community members in providing free energy audits to area residents. These audits of low income areas will find the largest sources of energy loss in homes and businesses and will provide simple solutions to the problem. Many local programs exist as examples, but currently only one program exists. Farmington had "make a difference day" at college, where they went to 10 homes with weatherization checklist. This could serve as a launching step for the program.

The air quality benefits to the region will be generated by increasing the energy efficiency of the homes and businesses involved in the program, therefore decreasing the amount of energy needed to be created by local coal burning power plants. In addition, those involved in the program can find out other sources by which to reduce their energy consumption (e.g. car pooling, appliance efficiencies).

II. Description of how to implement

A. Mandatory or voluntary: The audit of a home should be made mandatory for any individual or family receiving energy assistance from state or local governments and/or utilities. For those not receiving assistance, the program is voluntary in scope.

Weatherization and insulation subsidization: PNM has a good neighbor program; grants could go to non-profits; rebates could be used.

B. Indicate the most appropriate agency(ies) to implement: Colorado/NM Offices of Energy Management and Conservations, Americorps or Vista programs

III. Feasibility of the option

A. Technical: Similar programs are prevalent nationwide, this option is technically feasible.
B. Environmental: The environmental benefits of energy efficiency programs are documented.
C. Economic: Most energy efficiency programs, especially implemented with volunteers, are economically viable and sustainable.

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the Work Group for this option All agreed.

VII. Cross-over issues to the other source groups None at this time.

Mitigation Option: The Use and Credit of Energy Efficiency and Renewable Energy in the Environmental Permitting Process

I. <u>Description of the mitigation option</u>
In principle, facilities implementing activities that lead to energy efficiency (EE) and rely upon renewable energy (RE) can receive additional incentives/ flexibility in their State air quality permits. A goal would be to provide alternatives to conventional energy sources that occur within the nexus of environmental, energy, and economic activities. Such an effort would also allow EE/RE to compete with traditional pollution control technologies to reduce emissions and encourage more environmentally-sensitive energy generation.

The benefits to industry might include: categorical permit exemptions for specific source categories that incorporate EE and/or RE if their use result in significant ambient air quality improvements; use of EE/RE to represent offsets for the purpose of major source NSR review; education and promotion of EE/RE for the purpose of avoiding a permit requirement (i.e., reducing emissions below de minimus regulatory thresholds or "syn minoring"); incorporating EE/RE as a control option in the Reasonable Available Control Technology (RACT) review process for minor sources located in non-attainment and attainment/maintenance areas, and; other benefits as identified. State air quality agencies could also provide benefits to industry by considering: "fast tracking" environmental permit requests of facilities incorporating EE/RE; recognizing participating facilities through various environmental leadership awards' programs; and, and other ideas as appropriate.

The benefits to the states could include: air quality improvements and help in avoiding future air quality problems; energy security; economic development (e.g., new jobs); environmental and energy leadership; facilitated collaboration between State and Federal agencies; and synergism of technical resources.

Such EE/RE approaches could be "codified" in State Implementation Plans, Supplemental Environmental Projects, and/or enforceable air pollution permits. EE/RE could also be tied to State Portfolio Standards (e.g., Colorado Renewable Energy Standards at 10% by year 2015) or other mechanisms.

II. <u>Description of how to implement</u>

A. <u>Mandatory or voluntary:</u> Voluntary for industry to enter into EE/RE agreements, though possibly enforceable through State permits or SIPs.

B. B. <u>Indicate the most appropriate agency(ies) to implement:</u> State Air Quality agencies or other authorities responsible for issuing air quality permits; State Offices' of Energy Management and Conservation (or like agencies); Department of Energy, if necessary in determining appropriate EE/RE initiatives;

<u>III. Feasibility of the option</u>

A. <u>Technical:</u> Technically, permitting agencies and interested industry would need to come up with a mutually satisfying definition of "EE/RE," including possibly setting minimum EE/RE requirements. For example, EE/RE efforts might include: establishing/ continuing "green" programs such purchasing wind power to generate a significant percentage of energy to operate office buildings and facilities; incorporating solar power; expanding the use of alternative vehicles as vehicles of first choice in industry fleets; using biodiesel fuel use in fleet vehicles; encouraging other industry partners to adopt green programs and assist them with expertise and experience (peer to peer mentoring); using industry and State resources, combined with other resources, to educate employees and general public to EE/RE measures; and, exploring grants and other funding mechanisms for EE/RE efforts. Also, it would make sense to start this on a pilot level scale to resolve any challenges that are identified in an initial effort.

B. Environmental: It's been demonstrated that there are direct environmental benefits from the use of EE and RE (e.g., reduced emissions of criteria and hazardous air pollutants, including SOx, NOx, mercury, etc.). Such EE/RE may also address concerns for impacts on regional haze and climate change.

C. Economic: EE/RE could be a significant financial gain for participating facilities in terms of: saved revenue from energy efficiency ("profits" could be re-directed to other aspects of the facility/industry); saved revenue by not having to transport fuels across the country, such as coal and heating oil; fuel price protection; reduced exposure to potential carbon taxation; an offset/trading value for early adopters and efficient reducers; public perception, and/or; others to be identified.

IV. Background data and assumptions used

Efforts would need to begin by establishing a workgroup with appropriate professionals who could illuminate opportunities to implement EE/RE through permitting and rule changes. Also, this initiative would need to work with permitting agencies' inventory groups to collect data to identify source categories that may be appropriate pilot project candidates for an EE/RE initiative.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium, as there are not many examples to draw upon. Also, mutually satisfying definitions of EE/RE would need to be developed.

VI. Level of agreement within the work group for this mitigation option.

TBD but is assumed to be medium to high, depending on the workload necessary to get this effort underway.

VII. Cross-over issues to the other source groups TBD

RENEWABLE ENERGY

Mitigation Option: Expand the Renewable Portfolio Standards (RPS) to be Mandatory for Coops and Municipalities

I. Description of the mitigation option

The installation of new renewable generation has the potential to reduce the quantity of fuel combusted at existing fossil generation facilities thereby reducing air emissions and may potentially reduce the size of new generation that is needed to be built in the future.

Investor owned electric utility companies in New Mexico are required to provide 5% of the total energy supplied to its retail customers via renewable energy beginning in January of 2006. This requirement grows by 1% per year until 2011 when the requirement is l0%. This Renewable Portfolio Standard (RPS) requirement is part of the Rule 572 which was adopted by the NM Public Regulation Commission (NMPRC) in December of 2002. The New Mexico State legislature later passed the Renewable Energy Act, signed by the Governor on May 19, 2004, which codified this rule.

II. Description of how to implement

A. Mandatory or voluntary

The Renewable Energy Act states that the NMPRC may require that a rural electric cooperative 1) offer its retail customers a voluntary program for purchasing renewable energy under rates and terms that are approved by the NMPRC, but only to the extent that the cooperative's suppliers make renewable energy available under wholesale power contracts; and 2) report to the NMPRC the demand for renewable energy pursuant to a voluntary program. The Act is silent regarding municipalities at this time.

B. Indicate the most appropriate agency(ies) to implement

The NMPRC, the New Mexico Environment Dept, the New Mexico Energy, Minerals and Natural Resources Dept.

III. Feasibility of the option

A. Technical: Resource maps indicate that there is a good solar resource in the Four Corners area; however, wind energy, biomass, and geothermal are somewhat limited. Solar power generation is still more expensive than fossil-fired generation at this time.

B. Environmental: The environmental benefits of off-setting fossil-fired generation with renewable generation are well documented.

C. Economic: Each individual utility must balance it own unique needs to maintain a balance between reliability, environmental performance and cost. Integrating renewables into a utilities generation portfolio can cause electric prices to increase and adversely affect reliability to the utility's customers.

IV. Background data and assumptions used

Economic Outlook for Various Generation Technologies (2010)				
	Efficiency (%)	Capacity Factor (%)	Overnight Capital Cost(1) ($/kW)	Cost of Electricity (COE)(1) ($/MWh)
Wind (Class 3 to Class 6)(9)	N/A	30-42	1190	53-69

Solar Thermal (Parabolic Trough)	N/A	33	3410	180
Biomass CFB	28	85	2160	67
Coal(2) PC SC	39	80	1350	44
Coal(2) PC USC w/ CO2 capture	30	80	2270	72
Coal(2) CFB	36	80	1480	53
IGCC(2) GE – Quench W/O CO2 capture	37	80	1490	51
IGCC(2) GE – Quench w/ CO2 capture	30	80	1920	65
NGCC(4) (@ $4/MM Btu)	46	80(5)	500	43
NGCC(4) (@ $6/MM Btu)	46	80(5)	500	59
NGCC(4) (@ $8/MM Btu)	46	80(5)s	500	76

Acronyms: kW- kilowatts; MWh – megawatts/hour; CFB- circulating fluidized bed; PC- pulverized coal; SC-supercritical; USC- ultra-supercritical coal; IGCC- integrated gasification combined cycle; CFB- coal-fired boiler; NGCC- natural gas combined cycle

Notes:
All costs in 2006$; COE in levelized constant 2006$ and includes capital cost. Capital Cost is overnight, W/O Owner, AFUDC costs.
All fossil units about 600 MW capacity; Pittsburgh#8 coal for PC, CFB, IGCC.
Based on Gas Turbine technology limitations to handle hydrogen
NGCC unit based on GE 7F machine or equivalent by other vendors;
Represents technology capability
Value shown is 10% emission of total. The remainder is assumed to be absorbed by the biomass plant crop growth cycle
Includes reservoir development and associated cost for fuel supply
Reinjection of fluid in closed loop operation assumed
Wind COE values estimated via 2005 EPRI TAG analysis.

V. Any uncertainty associated with the option (Low, Medium, High)
High. Generally, the co-ops and municipalities do not like mandates.

VI. Level of agreement within the work group for this mitigation option
Mixed due to the fact that municipalities and rural electric cooperatives in the Four Corners area are relatively small and any participation in a statewide RPS will have a minimal impact on air quality.

VII. Cross-over issues to the other Task Force work groups None identified.

Mitigation Option: Four Corners States Adopt California Standards for Purchase of Clean Imported Energy

I. Description of the mitigation option

California has adopted a law that bans import of power from sources that generate more greenhouse gases than in-state natural gas plants. This law, which goes into effect January 1, 2007, impacts power generated in coal-fired plants in the Four Corners area, among others. Critics of this law say it will not accomplish its purpose of reducing emission of greenhouse gases, particularly carbon dioxide, because power from plants that do not meet CA's standards will simply be sold in other markets. If the Four Corners states (CO, NM, UT and AZ) adopted similar rules, pressure would be placed on the owners of many, if not all, the dirty plants in our area, plus a number of others, to clean up their emissions to meet the new standards. In so doing, a real contribution to the reduction of greenhouse gases, as well as other pollutants, would be made.

II. Description of how to implement

Four points relative to the CA legislation need to be addressed.

First, to be effective in a timely way, the rules need to apply to a utility's existing contracts that extend beyond a reasonable period of time, for example, five years. In anticipation of the January 1 implementation date for the CA law, some CA cities are renegotiating their long-term contracts, and extending them out to 2044. This must be avoided. Incentives will have to be provided to both sides in order to entice them to renegotiate their contracts

Second, some of the motivation for contract renegotiation relates to significant reductions in cost of power after the capital costs of the plant are retired. Incentives for renegotiation for similar reasons must be reduced or eliminated.

Third, state laws in the Four Corners area must specify power imported from 'other jurisdictions', such as from tribal nations as well as other states, in order to be effective in our area, since most present and future coal-fired power plants will be built on tribal lands, albeit within one of the Four Corners states. Additionally, tribal jurisdictions may wish to adopt similar legislation on the importation of power into their lands from external sources.

Fourth, the Four Corners states may not have a standard comparable to CA's standard, i.e., that of the greenhouse gas emissions of 'in-state natural gas plants'. In lieu of an appropriate in-state standard, a state could adopt CA's standard, or the average emission level for natural gas fired plants on a national level.

These requirements must be mandatory if they are to be effective

State and tribal permitting agencies should be given responsibility of implementation

III. Feasibility of the option

Technical - Four Corners states can seek technical assistance from the state of CA, which should be willing to assist in order to avoid dilution of the impact of their own law. Monitors of greenhouse gas emissions will need to be in place if not already in use

Environmental – This option would have a significant environmental impact

Economic – This option would also have a significant economic impact. There is no doubt that plants requiring significant pollution upgrades or even plant phase outs would raise the cost to shareholders and that these costs would be passed along to the customer. However, this is appropriate. End runs around the legislation, such as, marketing the power outside CA and the Four Corners area would occur to some extent. Obviously, addressing this issue at a national level would be far superior to a state-by-state approach; however, in lieu of national action, this option takes CA's step significant further.

Political – this option will be a very hard sell. Constituents in all Four States include citizens, including tribal members, with financial interests in status quo.

Legal – Since the U.S. Constitution gives Congress the power to regulate inter-state commerce, CA's law may not hold up to judicial scrutiny. If it doesn't, then this option would be withdrawn.

IV. Background data and assumptions

This option assumes legality, constitutionality and permanence of the CA law. This option would be withdrawn if the Supreme Court gives the EPA the power to regulate greenhouse gases in the case heard November 29 and if the EPA then takes a stance at least as tough as the CA standard.

V. Any uncertainty associated with the option

This option has lots of uncertainty related to political and legal feasibility.

VI. Level of agreement within the work group for this option TBD.

Mitigation Option: Net Metering for Four Corners Area

I. Description of the mitigation option

Providing electricity consumers in the Four Corners area with net-metering agreements would allow each consumer to generate their own electricity from renewable resources to offset their electricity use. A net-metering law also mandates that a utility cannot charge more for your electricity than they pay you for the solar(renewable) power you generate. Net metering would make small house/business renewable systems more feasible.

Increased capacity of renewable energy systems in the Four Corners and around the world, will lead to less need for new coal-fired power plants and their associated emissions

EPA has just released a new edition of its Emissions and Generation Integrated Resource Database (eGRID). eGRID is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States. It contains emissions and emissions rates for NOx, SO2, CO2 and mercury. The database also contains fuel use and generation data.
In the United States, electricity is generated in many different ways, with a wide variation in environmental impact. Traditional methods of electricity production contribute to air quality problems and the risk of global climate change. With the advent of electric customer choice, many electricity customers can now choose the source of their electricity. In fact, you might now have the option of choosing cleaner, more environmentally friendly sources of energy. According to the EGRID Power Profiler, it is possible to generate a report, for example about City of Farmington electricity use. EGRID provides fuel mixes, i.e. how is our power being generated. For Farmington the mix is approximately 13% Hydroelectric, 13% gas, and 74% coal. E-GRID also provides the corresponding emissions rate estimates. For Farmington, emissions rates associated with the electricity generation (lbs/MWh) are 3.1 NO2, 3.3 SO2, and 1873 CO2

Info on E-GRID is available at http://www.epa.gov/cleanenergy/egrid

Net metering programs serve as an important incentive for consumer investment in renewable energy generation. Net metering enables customers to use their own electricity generation to offset their consumption over a billing period by allowing their electric meters to turn backwards when they generate electricity in excess of their demand. This offset means that customers receive retail prices for the excess electricity they generate. Without net metering, a second meter is usually installed to measure the electricity that flows back to the provider, with the provider purchasing the power at a rate much lower than the retail rate.Net Metering Policy:

Net metering is a low-cost, easily administered method of encouraging customer investment in renewable energy technologies. It increases the value of the electricity produced by renewable generation and allows customers to "bank" their energy and use it a different time than it is produced giving customers more flexibility and allowing them to maximize the value of their production. Providers may also benefit from net metering because when customers are producing electricity during peak periods, the system load factor is improved.

There are three reasons net metering is important. First, as increasing numbers of primarily residential customers install renewable energy systems in their homes, there needs to be a simple, standardized protocol for connecting their systems into the electricity grid that ensures safety and power quality. Second, many residential customers are not at home using electricity during the day when their systems are producing power, and net metering allows them to receive full value for the electricity they produce without installing expensive battery storage systems. Third, net metering provides a simple, inexpensive, and easily-administered mechanism for encouraging the use of renewable energy systems, which provide important local, national, and global benefits

History:
On September 30, 1999, the New Mexico Public Regulation Commission (PRC) adopted a rule requiring all utilities regulated by the PRC to offer net metering to customers with cogeneration (CHP) facilities and small power producers with systems up to 10 kilowatts (kW) in capacity. Municipal utilities, which are not regulated by the PRC, are exempt. There is no statewide cap on the number of systems eligible for net metering.

For any net excess generation (NEG) created by a customer, the utility must either (1) credit or pay the customer for the net energy supplied to the utility at the utility's "energy rate," or (2) credit the customer for the net kilowatt-hours of energy supplied to the utility. Unused credits are carried forward to the next month. If a customer with credits exits the system, the utility must pay the customer for any unused credits at the utility's "energy rate." Customer-generators retain ownership of all renewable-energy credits (RECs) associated with the generation of electricity. [from DSIRE – Database of State Incentives for Renewable Energy – New Mexico]

Benefits:
Utilities benefit by avoiding the administrative and accounting costs of metering and purchasing the small amounts of excess electricity produced by these small-scale renewable generating facilities. Consumers benefit by getting greater value for some of the electricity they generate, by being able to interconnect with the utility using their existing utility meter, and by being able to interconnect using widely-accepted technical standards.

Tradeoffs: The main cost associated with net metering is indirect: the customer is buying less electricity from the utility, which means the utility is collecting less revenue from the customer. That's because any excess electricity that would have been sold to the utility at the wholesale or 'avoided cost' price is instead being used to offset electricity the customer would have purchased at the retail price. In most cases, the revenue loss is comparable to having the customer reducing electricity use by investing in energy efficiency measures, such as compact fluorescent lights and efficient appliances.

Special meters may also cost customer some installment costs

II. Description of how to implement

A. Mandatory or voluntary
Utilities should be required to providing Net metering arrangements for electricity users.

B. Indicate the most appropriate agency(ies) to implement
City of Farmington Utility, other Four Corners local utilities and Coops

Two comments were received on this option during the Task Force Report Public Comment Period:

“Not only do we need net metering with our local utility (Farmington Electric Utility System), it needs to be encouraged and not expensive to sign up. These are small steps toward diversifying our energy sources, and we are in a prime solar area for generating home-based electricity.”
“A net metering program would be positive if implemented with the proper subsidies to encourage citizens to get involved. Many people in the Four Corners area are not in the financial position to invest in the start-up program; this would have to come from state government programs for those who qualify.”

See all the public comments received for EEREC section in the appendix to this section.

III. Feasibility of the option

A. Technical

The standard kilowatt-hour meter used by the vast majority of residential and small commercial customers accurately registers the flow of electricity in either direction. This means the 'netting' process associated with net metering happens automatically-the meter spins forward (in the normal direction) when the consumer needs more electricity than is being produced, and spins backward when the consumer is producing more electricity than is needed in the house or building. [HP magazine, Net Metering FAQs]

It may be necessary to purchase a new meter.

B. Environmental

Use of renewable energy in the Four Corners area would offset emissions generated by polluting energy sources by approximately, 3.1 lbs NO_2, 3.3 lbs SO_2, and 1873 lbs CO_2 per MWh energy production.

Solar electric and wind energy systems can be expensive; however, if a systems design approach is used taking due account of conservation and energy efficiency, the system can be profitable.

C. Economic

Solar electric and wind energy systems can be expensive; however, if a systems design approach is used taking due account of conservation and energy efficiency, the system can be profitable.

Net-metering makes good economic sense. It is a fair approach and agreement between utility and consumer to buying and selling electricity

IV. Background data and assumptions used

1 Green Power Markets, Net Metering Policies
http://www.eere.energy.gov/greenpower/markets/netmetering.shtml

2 American Wind Energy Association: http://www.awea.org/faq/netbdef.html

3 Go Solar California Net Metering
http://www.gosolarcalifornia.ca.gov/solar101/net_metering.html

4 Database of State Incentives for Renewable Energy
http://dsireusa.org

5 Home Power Magazine, Net Metering FAQs:
http://www.homepower.com/resources/net_metering_faq.cfm

6. Solar Living Source Book, John Schaeffer, 2005

V. Any uncertainty associated with the option (Low, Medium, High) Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

Mitigation Option: New Programs to Promote Renewable Energy Including Tax Incentives

I. Description of the Mitigation Option

The Four Corners Region is recognized as having excellent solar and wind resources yet the incentives to use and develop renewable energy sources in Colorado (southwestern Colorado in particular) are extremely limited. For example, in Montezuma County, Colorado, net metering and the Federal Tax Credit for Solar Energy Systems are the only renewable energy incentives offered to residential power users. This mitigation option proposes several opportunities to diversify the incentives used to promote, develop, and increase the use of renewable energy in Colorado and other Four Corners states. The diversification of incentives will help Colorado in particular meet or exceed its current renewable energy standard (1), increase the overall use of renewable energy, reduce dependence on coal burning power sources, and reduce coal power plant emissions.

A 2003 report by the Union of Concerned Scientists gives "grades" to all states in the U.S. regarding the use and commitment to clean, renewable energy sources (2). Renewable energy sources include wind, geothermal, solar and bio-energy. In 2003, New Mexico received a grade "B+/B" (among the top 5 states in the nation) because of its commitment to increase the use of renewable energy by at least 0.5 percent per year. Currently, New Mexico has a renewable energy standard of 10 percent by the year 2011. In the same report, Colorado received a grade of "F" due to low levels of existing renewable energy and no commitment for future renewable energy development. This situation has improved since Colorado Amendment 37 passed in 2004 requiring a state-wide renewable energy standard. Colorado utilities are now required to obtain 3 percent of their electricity from renewable energy sources by 2007 and 10 percent by 2015. Even with the Colorado Amendment 37 law, incentives for encouraging the development of renewable energy in Colorado are extremely limited. There is tremendous opportunity to implement the many incentives already used in western states such as New Mexico, California and Nevada.

Incentives in this mitigation option would greatly accelerate the construction, maintenance, and expansion of solar and wind power generation. Wind and solar power sources create zero emissions of NOx, SOx, and CO2 (3). For this reason, solar and wind are the primary focus of this mitigation option.

INCENTIVES FOR RENERABLE ENERGY PROJECTS *

Incentive	**Description**	**Incentive Currently Offered?**		**Who Can Implement?**
		Colorado	**New Mexico**	**Authority**
Building Permit Fee Waiver for Solar Projects	Waive building permit fees when qualifying solar energy systems are installed in commercial/residential construction projects.	N	N	County/City
Leasing Solar Water Heating Systems	Service provider installs and maintains solar water heating systems for residents. Hardware owned and maintained by service provider. User pays installation fees and monthly utility fees based on system size.	N	N	Utility companies, city or county water & sanitation utilities
Renewable Energy Rebates/Credits	Rebates and/or credits (often based on system size) for purchase and	Only in a few areas,	N (?)	Utility companies

(System Costs)	installation costs of new grid-connected renewable energy systems that meet minimum energy efficiency qualifications.	including La Plata/Archuleta Counties.		
Renewable Energy Rebates/Credits (Net Metering)	Rebates and or credits for excess energy produced from grid-connected renewable energy systems.	Y	Y	Utility companies
Tax Deduction/Credit #1	Tax deduction or credit for 100% of the interest on loans made to purchase renewable energy systems or energy efficient products and appliances.	N	N	States
Tax Deduction/Credit #2	Property Tax deduction for qualifying solar photovoltaic systems.	N	N	States
Tax Deduction/Credit #3	Corporate income tax credit for companies with qualifying low or zero emissions renewable energy systems > 10 MW	N	Y	States
Tax Deduction/Credit #4	Personal income tax credit (plus Fed. Tax credit) up to 30% or $9,000 for on or off-grid photovoltaic and solar hot air systems.	N	Y	States
Sales tax exemption for Biomass Equipment and Materials	Commercial and industrial sales tax (compensating tax) exemption for 100% of the cost of material and equipment used to process biopower.	N	Y	States
Supplemental Energy Payments (SEP's)	SEPs are made for eligible renewable generators to offset above-market costs of investor-owned utilities to meet their renewable energy standard portfolio obligations.	N	N	States
Bond Programs for Public Buildings	Bonds provided to schools and public buildings to upgrade to energy efficient heating/lighting or installation of renewable energy power systems. Bonds paid back through savings on energy bills.	N	Y	States
Grant Programs	Grants provided for up to 50% of the cost of design, installation and purchase of renewable energy systems for residential and commercial/industrial	N	N	Utilities, States, residences
Energy Efficient Standards for State	Requirement for all new public building construction to achieve US	Only where economical	Y	States, local governments in

Buildings	Green Building Council Leadership in Energy and Environmental Design (LEED) ratings based on size. LEED systems emphasize energy efficiency and encourages use of renewable energy sources.	ly feasible		Colorado
Loan Programs	Zero interest loans offered for qualifying photovoltaic and solar water heat systems	Only a few locations, none in SW Colorado	N	Local communities, utilities and financial partners

* Incentives in this table were developed by comparing incentives currently used in New Mexico, California, Nevada, and Colorado (4)

Benefits: Incentives will be necessary to increase the use of renewable energy, especially for the typical residential power user. Colorado's renewable energy program is relatively new and is stimulating a developing renewable energy market. The timing is very good to implement and support a diverse incentive program to meet or exceed the State's renewable energy standard, and increase the overall use of renewable energy. An increased use of clean renewable energy will result in a corresponding decrease in NOx, SOx, and CO2 produced by coal-fired power generation.

Tradeoffs: Several incentive options would require legislation or other mechanisms of State governments and would require some time to set in place. Many incentives would be offered by State government in the form of tax incentives and may slightly decrease State tax revenues. The use of incentives listed in the above table by several western states is a good indication they work effectively and provide value to that State. They can be implemented by Colorado and other Four Corners region states.

II. Description of How to Implement

A. Voluntary or mandatory – Incentives, by definition, would be voluntary for the consumer. It could be voluntary or mandatory for the States, local government, or utility companies to offer the incentives.

B. Indicate the most appropriate agency(ies) to implement – See Incentives Table above for appropriate agency for each incentive measure.

III. Feasibility of the Option

Public and corporate knowledge regarding the environmental benefits and cost benefits of solar and wind alternative energy systems is limited, and could be greatly improved. The diversification of incentives could stimulate interest in renewable energy systems.

A. Technical: The technology for wind and solar power systems, and solar water heating and space heating is currently widely available. Improvements to make these technologies more efficient and affordable is ongoing. Using incentives to increase the use and demand for these systems would stimulate further technological advances.

B. Environmental: A 10 percent increase in the use of renewable energy in Colorado will result in a reduction of 3 million metric tons of CO2 per year in 25 years (5). It would also result in the reduction of SO2 and NOx.

C. Economic: 1) Increased demand and use of solar and wind energy systems will stimulate accelerated improvements in solar and wind energy technology and reduce costs of the technology in the long term. 2) Implementing incentives for individuals and corporate/businesses will stimulate and accelerate the use of existing wind and solar technologies. 3) Increased use through incentives will create an expanding market for producers (6), and could create up to 2,000 new jobs in Colorado in manufacturing, construction, operation, and maintenance and other industries in 25 years (5) 4) Increased use of the technology would reduce and energy costs to consumers and insulate the economy from fossil fuel price spikes (7).

IV. Background Data and Assumptions Used

(1) A renewable energy (or electricity) standard is a requirement by a state or the Federal government for utilities to gradually increase the portion of electricity they produce from renewable energy sources.

(2) Union of Concerned Scientists, 2003. Plugging in Renewable Energy, Grading the States. www.ucsusa.org/clean_energy

(3) American Wind Energy Association, 2006. Wind Energy Fact Sheet – Comparative Air Emissions of Wind and Other Fuels. 122 C Street, Washington, D.C., 2 pp.; citation for solar).

(4) Database of State Incentives for Renewable Energy (DSIRE), 2006. New Mexico, Colorado, Nevada, and California Incentives for Renewables and Efficiency. www.dsireusa.org/ ; Governor's Office of Energy Management and Conservation, 2006. Rebuild Colorado, Utility Incentives for Efficiency Improvements and Renewable Energy. www.colorado.gov/rebuildco ; Martinez, Louise, 2006. Presentation to the Four Corners Task Force – New Mexico Clean Energy Programs. New Mexico Energy, Minerals, and Natural Resource Department, presentation in Farmington NM, November 8.

(5) Union of Concerned Scientists, 2004. The Colorado Renewable Energy Standard Ballot Initiative: Impacts on Jobs and the Economy. www.ucsusa.org/clean_energy/clean_energy_policies/the-colorado-renewable-energy-standard-ballot-initiative.html

(6) Gielecki, Mark, F. Mayes, and L. Prete, 2001. Incentives, Mandates, and Government Programs for Promoting Renewable Energy. Department of Energy, 26 pgs. www.eia.doe.gov/cneaf/solar.renewables/rea_issues/incent.html

(7) Union of Concerned Scientists, 2006. Renewable Energy Standards at Work in the States. http://www.ucsusa.org/clean_energy_policies/res-at-work-in-the-states.html

V. Any Uncertainty Associated With the Option (Low, Medium, High)

Low – Increasing the use of renewable energy sources is widely accepted as a practice which will decrease air pollution emissions associated with burning fossil fuels. Increasing incentives would increase the widespread use of renewable energy systems.

VI. Level of Agreement within the Work Group for this Mitigation Option TBD.

VII. Cross-over Issues to the Other Source Groups None at this time.

Mitigation Option: Promote Solar Electrical Energy Production

I. Description of the mitigation option

A. Promote Solar Electrical Energy Production:
The region in general has good solar energy possibilities, a large number of clear days with very few successive days of clouds. If storage was not used it means that there would be power to feed to the distribution system during peak solar intensity. The power density is also quite favorable being in the range of 600 to1000 W/m2 for peak values (winter, summer). In the summer this would match the large load of air-conditioning, it would not match the winter load. Solar electrical has a developed technology with standards and while the systems are complex, especially if feedback to the power grid is done, it is not beyond the capabilities of trained people in the area.
B. Reduce Electrical Energy Consumption by Substituting Solar Energy:
The reduction of electrical energy consumption for home heating and hot water production can be replaced or supplemented by solar energy inputs. These would be significant for the individual household but these households are a small percentage of the general population. All buildings use solar energy, it is just a matter of degree. All can be improved to make better use of the solar energy which we have available, reducing other energy consumption.

II. Description of how to implement

A. Mandatory or voluntary:
Voluntary on the part of the person with the solar electric installation and with agreement of the electric utilities company, possibly with legal control by the state. Utilities would specify interconnect requirements.
B. Indicate the most appropriate agency(ies) to implement
Utilities/State

III. Feasibility of the option

A. Technical: For solar electrical systems, new inspectors would be needed or present ones reeducated. You may need a change in distribution control system.
B. Environmental: The environmental results of shifting the energy consumption from fuels (gas, oil, coal) burned in the region to solar means a reduction of all types of air pollutants by what ever reduction was achieved.
C. Economic: Not that practical unless the person is far off the grid. Would most likely need incentives (tax?). Large capital out lay to replace ongoing expenses of fuel. If other energy sources are replaced by solar, taxes will be lost.
D. Political: Since regulation and taxes may be involved this could be a problem.

IV. Background data and assumptions used:

6000-7000 heating degree days for the region
1500 cooling degree days for the region
6 usable solar hours per day (yearly average).
5 usable solar hours per day (winter average)

V. Uncertainty associated with the option (Low, Medium, High):

Low for would it work, High for could you get enough people doing it to have a significant affect.

VI. Level of agreement within the Work Group for this option TBD

VII. Cross-over issues to the other source groups None

Mitigation Option: Subsidization of Land Required to Develop Renewable Energy

I. Description of the mitigation option
Land required for larger renewable energy projects, especially solar electric energy production, would be subsidized. This option would help to promote and make renewable energy production more feasible.

BLM/FS has a large amount of unused land. Some large renewable energy projects could be demonstrated on that land. A collaborative program should be developed with US Government owners of NW NM land to provide cheap or in some case potentially free land leases to companies that are willing to develop renewable energy production facilities. Barriers should be reduced.

The Navajo Nation and other tribes in the Four Corners area own a large amount of land in the Four Corners area. There has been some interest in wind energy development on Native American land in Arizona. Available land resources on the reservation could be used to develop renewable energy projects and stimulate the local economy.

Benefits: Solar electric energy is clean energy.
Solar electric energy production could complement and eventually displace coal fired power plant electricity generation. Eventually, over time, promotion and expansion of solar electric energy production could replace the need for a new coal-fired power plant. This alternative strategy to energy production would then displace the air pollution emissions associated with that power plant.

Solar electric energy development in the Four Corners area would stimulate the photovoltaic equipment and service industry here.

Burdens: Land resource would be needed (see feasibility section). We have estimated the amount of land required to generate 1 MW of solar electric capacity.

II. Description of how to implement
A. Mandatory or voluntary
Mandatory. A rule would need to be created describing the subsidization amount and conditions.

B. Indicate the most appropriate agency(ies) to implement
Four Corners government property owners such as BLM, FS, and Navajo Nation

III. Feasibility of the option
A. Technical
The amount of land required to produce 1 MW solar electric generation capacity

For Farmington, NM a Flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees avg. of 6.3 hours of full sun. Full sun is 1,000 watts per square meter.

For our estimation we will use large Evergreen Cedar-series ES-190 W Spruce Line Module with MC Connectors, rated by California Energy Commission, http://www.consumerenergycenter.org/cgi-bin/eligible_pvmodules.cgi, at 166.8 watts output.

Based on our location in Farmington, 166.8 watts x 6.3 hours, we have a per day 1050 watt-hr per day per module. Module is approximately 61.8" x 37.5", surface area is 16.1 square feet. Allow extra space and we will need approximately 20 square feet per module.

Assume DC output to conventional AC power conversion inefficiency of 95%, CEC

1.05 KWh per module per day is reduced to approx 1 KWh at AC grid.

Conversion: 43,560 square feet in an acre
2178 modules could be fit on area of 1 acre.
This # of PV modules would generate approximately 2.2 MWh of energy.
At Farmington site this corresponds to approximately 345 KW of solar electric generation capacity.

Therefore, we could fit could generate 1 MW of electricity during daylight hours on about 3 acres of land in Farmington. Based on the solar irradiance values for Farmington this would be about 2.2 MWh of energy per day.

[Real Goods Solar Living Sourcebook, John Schaeffer, 12th edition, 2005, p.57 method of design used]

B. Environmental: Photovoltaic modules do not have significant negative environmental costs

C. Economic: Each module in example would cost approximately $1,000. There is a large amount of open land available, not in use, on government land in the 4 Corners area. Renewable energy projects could provide local jobs and help economy.

IV. Background data and assumptions used

1. California Energy Commission, http://www.energy.ca.gov/, PV specifications
2. Evergreen Solar PV module product information, http://www.evergreensolar.com/
3. Farmington, NM Solar Insolation data from San Juan College Renewable Energy Program

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups None

Mitigation Option: Use of Distributed Energy

I. Description of the mitigation option

Distributed energy refers to decentralized generation and use of relatively small amounts of power, usually on demand in a local setting. Excess power may or may not be delivered to the grid. This option would encourage the use of distributed energy by owners of residential or commercial buildings or neighborhoods, where practical and feasible. While it is generally accepted that centralized electric power plants will remain the major source of electric power supply for the future, distributed energy resources (DER) can complement central power by providing incremental capacity to the utility grid or to an end user. Installing DER at or near the end user can also benefit the electric utility by avoiding or reducing the cost of construction of new plants to meet peak demand and/or of transmission and distribution system upgrades.

Distributed energy encompasses a wide range of different types of technologies. The Department of Energy, the state of California and various trade groups have programs encouraging research into and use of these technologies. Distributed energy technologies are usually installed for many different reasons. This option focuses on any distributed energy options that reduce demand on grid sources and thereby reduce the demand for new large power plants and/or transmission costs. While excess power generated by distributed sources and delivered to the grid can aid in reduction of power demand on centralized sources, distributed energy options are also important in serving needs in areas not currently attached to the grid thereby reducing the need for hookup to the grid.

Since these technologies are individual and/or local in nature, the burden would be on the prospective homeowner and building owner to seek out options and financing and a contractor who is sufficiently knowledgeable to suggest options and skilled enough to implement them. Initially, mortgage support or grants may also be needed to encourage implementation.

For the environmentally conscious consumer, the use of renewable distributed energy generation and "green power" such as wind, photovoltaic, geothermal or hydroelectric power, can provide a significant environmental benefit. However, the potential lower cost, higher service reliability, high power quality, increased energy efficiency, and energy independence are additional reasons for interest in DER.

II. Description of how to implement

The choice to use distributed energy resources and specifically which one(s) are appropriate should be voluntary. The decision can involve higher capital costs, and the willingness to invest in technologies that may be new and not widely implemented. Federal, state and local departments of energy should support research into options most suited to a particular geography and climate; loans and grants should be available and experts should be retained to consult with potential users.

III. Feasibility of the option

A. Technical – Information on various choices is available, choices range from low-tech to high-tech
B. Environmental – Any options that reduce the demand on the centralized power grid and minimize their own pollution will contribute to an improved environment by reducing the need for coal-fired power plants in our area
C. Economic – Options range in cost. Greater use of options should ultimately result in reduced unit costs
D. Political – Use of distributed energy resources should be an easy sell politically; the degree to which federal and state research and resources are already available, indicates a public commitment already in place

IV. Background data and assumptions N/A

V. Uncertainty – This option has a high degree of certainty that it could be implemented and be effective.

VI. Level of agreement within the work group for this option TBD

VII. Cross-over issues to the other source groups None at this time.

CONSERVATION

Mitigation Option: Changes to Residential Energy Bills

I. Description of the mitigation option

Energy for many households in the four corners area is delivered as electricity and/or natural gas. Residential energy is used for home heating, hot water, and to run appliances. Most residential consumer receives monthly bills. Examples of typical electric and gas bills are shown in Figures 1 and 2, respectively.

Figure 1. Residential electric utility bill with sample energy cost savings

Electric Association Bill (Colorado)									
Account Information									
SERVICE DATE		NO. DAYS	RTE/SEQ	METER READING		MULTI PLIER	kWh USAGE	CHARGES	
PREVIOUS	PRESENT			PREVIOUS	PRESENT				
9/18/2006	10/16/2006	28	403-160	1	612	1	612		
				LAST AMOUNT BILLED				95.07	
				PAYMENT MADE -- THANK YOU				95.07	CR
				…….					
				ENERGY CHARGES				54.30	
				CITY TAX				2.97	
				BASIC CHARGE				15.50	
				FRANCHISE FEE				3.49	
				TOTAL CURRENT CHARGES				76.26	
COST COMPARISON	DAYS SERVICE	TOTAL kWh	AVG. kWh/DAY	kWh COST/DAY					
CURRENT BILLING PERIOD	28	612	22	2.72		TOTAL DUE		76.26	
PREVIOUS BILLING PERIOD	34	806	24	2.24		BILLING DATE:		10/20/2006	
SAME PERIOD LAST YEAR	28	676	24	2.72		DUE DATE:		11/6/2006	
Example of possible cost savings for an electric hot water heater									
Most efficient	4622	kW/yr							
Anticipated monthly saving in kWh/yr			21	kWh					
Monthly dollar saving @ your rate of 12.5 cents / kWh			2.65						
Savings over a 13 year life			412.78						

Figure 2. Residential gas utility bill with sample energy cost savings

Energy (gas) Company Bill (Colorado)									
			DATE OF SERVICE		METER READING				
BILLING INFORMATION:			FROM	TO	PREVIOUS	PRESENT			
METER DEPOSIT	347.00		10/02/06	11/01/06	9750	9845			
PREVIOUS BALANCE			RATE CODE:	36QC					
			USAGE IN CCF:	78					
CURRENT GAS CHARGE TOTAL		85.15	PRESSURE FACTOR:		0.819				
FACILITY CHARGE	21.50			Usage this month		95	therms		
COM LDC COST @ .16000/CCF	12.45			Example of possible cost savings for a gas hot water heater					
UPSTREAM COST @ .02530/CCF	1.97			Most efficient		230		therms/year	
COMMODITY COST @ .67930/CCF	52.86			Anticipated monthly saving in therms				4	kWh
DEFERRED GAS COST @ -.09880/CCF	-7.69			Monthly dollar saving @ your rate of 0.97 cents				3.88	
FRANCHISE FEE @ .05000	4.06			Savings over a 13 year life				605.28	
SERVICE CHARGE TOTAL		0.54							
PENALTY	0.54								
TAX TOTAL									
STATE TAX @ .02900	2.47								
CITY TAX @ .04050	3.44								
COUNTY TAX @ .00450	0.38								
CURRENT CHARGES		91.98							
TOTAL AMOUNT DUE		91.98							

A typical energy bills lists meter readings, cost breakdowns, and other technical information. Much of the information on monthly energy statements is required by regulatory bodies and laws. Most importantly, a typical bill does not provide the consumer with information to make decisions on energy conservation and the ability to translate proposed conservation options to dollars saved.

The suggested mitigation option is to have an additional place on monthly bill that would feature one energy conservation step that a consumer may take and indicate cost savings. In the examples presented, a cost saving for a new energy efficient hot water heater is shown (bold box in Figure 1 and in Figure 2). Another monthly statement could show the amount of savings that may result from lowering the thermostat one degree Fahrenheit. A statement of energy saving on the bill would be more effective that simply including a generic insert in the bill. These often are quickly discarded.

In addition, we recommend that all energy bills have a graph that shows 1) year to month energy used for the current and past year and monthly use comparing the current to the previous year.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary
B. Indicate the most appropriate agency(ies) to implement:
Energy companies

III. Feasibility of the option

A. Technical: Some reprogramming of residential energy billing program
B. Environmental:
C. Economic: Cost of reprogramming software

IV. Background data and assumptions used

V. Any uncertainty associated with the option (Low, Medium, High) Medium

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other Task Force work groups: Unknown

Mitigation Option: County Planning of High Density Living as Opposed to Dispersed Homes throughout the County

I. Description of the mitigation option

San Juan County is presently starting the process of developing a county wide growth master plan. A number of questions in their citizens questionnaire were if there should be encouragement or restrictions in development of home sites in the rural areas of the county and if this growth should be low or high house value. From the point of view of energy conservation and hence reduced pollution of many types the county should be encouraged to develop a plan which encourages clustering of housing (not in the far rural areas) so as to reduce energy losses on distribution lines and the reduction of travel distances for transportation. The ideal clustering should be near employment and services. Other counties in the Four Corners should be encouraged to also follow this pattern.

II. Description of How to Implement:

A. Mandatory or voluntary

While you cannot force people to do this, encouragement by tax policies, varying rates based on distances for electrical services, zoning or other methods would be helpful.

B. Indicate the most appropriate agency(ies) to implement

Taxes and zoning would be under the county government while the rates would be with the electric utilities companies of allowed by law. I do not know how much latitude they have.

III. Feasibility of the option

A. Technical: No problems

B. Environmental: None until specifics are assumed.

C. Economic: Concentrated populations, within limits, will have an advantage of reduced infrastructure coast.

D. Political: The greatest problem with this option will be general resistance to the ideal by the general public and very great resistance from those with vested interest.

IV. Background data and assumptions used San Juan county citizens' questionnaire.

V. Uncertainty associated with the option (Low, Medium, High) TBD.

VI. Level of agreement within the Work Group for this option TBD.

VII. Cross-over issues to the other source groups None at this time.

Mitigation Option: Direct Load Control and Time-based Pricing

I. Description of the mitigation option

Overview
This option describes demand response tools focused on direct load control and electric pricing. By offering direct load control and electric pricing options around time-of-day, critical peak and seasonal use, customers are provided with an effective price signal regarding when and how they use electricity. Demand response ("DR") is the label currently given to programs that reduce customer loads during critical periods. In the past, DR programs have also been called "load management" and "demand-side management" programs. Most demand response programs currently focus on either peak load clipping through direct load control or load shifting through time-based pricing mechanisms. The primary goal of DR programs is to reduce peak demand. The concerns regarding impending major capital expenditures by utilities for additional generating and transmission system capacity and the impact of energy consumption on the environment has sparked a renewed interest in utility programs to reduce the amount of energy used during periods when the generation and power delivery infrastructures are most constrained and at their highest costs. Reductions in peak demand may or may not be accompanied by a reduction in the total amount of energy consumed. This is because DR programs may result in energy consumption simply being shifted to a period when the utility system is not as constrained and market prices are lower.

Air Quality and Environmental Benefits- Demand response programs primary purpose is to reduce peak load. These programs may not lead to energy conservation nor should they be relied upon to do so (Energy efficiency programs are specifically designed to reduce the total amount of energy used by customers on an annual basis).
These programs may allow utilities to hold off on building new generating plants and permit technology to develop and mature in the areas of clean coal generation as well as renewable energy.
(As an indirect benefit, if customers do choose to conserve energy, the reduction in energy use may lead to a reduction in the need for energy generation resulting in emission reductions in air pollution and greenhouse gases).

Economic: Customer charge for the installation and use of automatic metering systems (where applicable) installed in participating residential and commercial customer homes and businesses
Cost to utility for administration and tracking of the program.

Trade-offs: Positive public relations, clean coal and renewable technology maturation

II. Description of how to implement

Mandatory or voluntary: Voluntary
Time of use pricing: Electricity is priced at two different levels depending upon the time of day. The inverted block rate is a rate design for a customer class for which the unit charge for electricity increases from one block to another as usage increases and exceeds the first block. The incentive is to use less energy and stay within the first block, which has the lowest rates.

Critical peak pricing: Critical peak pricing is a pricing scheme that encourages customers to reduce their on and mid-peak energy usage by offering incentives through an alert-based, monitoring system.

Seasonal use pricing: Electric rates vary depending upon the time of year. Charges are typically higher in the summer months when demand is greater and the cost to generate electricity is higher. For example, during the months of June through September, electricity rates would be higher than other months.

The public utility commission is the most appropriate entity to implement.

III. Feasibility of the option

Technical: Good feasibility. Programs have been applied and demonstrated at utilities across the country. Automated and advanced metering systems are commercially available.

Environmental: Medium feasibility for indirect benefits. Prices and advanced metering systems can be used to modify customer behavior to use less electricity within individual homes and businesses during peak hours. This may or may not lead to energy conservation. However, such programs may allow utilities to hold off adding new generation assets, thereby, improving opportunities for employment of more advanced, demonstrated and cost-effective clean coal and renewable energy technology.

Economic: Good economics. Advanced metering systems, in addition to better enabling time-based rates, can deliver load control signals to end-use equipment and provide consumers with energy consumption and price information to assist with shifting load from on-peak to off-peak periods, thereby saving the customer money on their utility bills. Direct load control and electric pricing options create long-term market transformations by shifting energy use to periods of lower plant and infrastructure constraints as well as lower market cost. As a result, utility maintenance and equipment replacement costs may be reduced and the cost to build new generation may also be postponed.

IV. Background data and assumptions used

Energy Administration Information, Department of Energy

Federal Energy Regulatory Commission, "Assessment of Demand Response & Advanced Metering"

Conservation is not the purpose of direct load control and electric pricing options. Energy efficiency programs are better suited to promote conservation.

V. Any uncertainty associated with the option (Low, Medium, High) Medium. Voluntary programs do not guarantee energy conservation and emissions reductions.

VI. Level of agreement within the work group for this mitigation option Good. This option write-up stems from a discussion at the November 8, 2006 meeting of the Power Plant Working Group.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

Other Sources Group- Pilot Neighborhood Project to Change Behavior to Reduce Energy Use and Energy Efficiency Programs

Mitigation Option: Energy Conservation by Energy Utility Customers

I. Description of the mitigation option

This option would require all generators of power (renewable and non-renewable sources) in the Four Corners area to develop a program which causes their customer base to reduce per capita power usage each year for five years until an agreed upon endpoint is reached. The owners of all facilities that generate power, irrespective of how it is generated, should be required to develop or participate in a program which encourages their customer base to reduce per capita, per household, per production unit (or whatever other measure is equivalent for non-residential customers) use of power each year for five years until some reasonably aggressive endpoint is reached. The percent annual reduction would be 20% of the difference between the baseline usage and the five year goal.

The goal or endpoint would be negotiated between industry trade groups, governmental agencies, environmental groups and interested parties and would vary depending on the climate at the location of the customer base. The set of endpoints thus determined would apply industry-wide and always be a challenge. Most measures observed to date depend on a percent reduction in per unit usage. The difference in this option is that the endpoint for each customer base is a specific achievable minimum amount of energy usage based on current technology.

This concept is similar to water conservation programs, which have successfully reduced water usage. Water companies have used incentives to promote the use of water saving devices – low water flush toilets, controls on shower heads, more efficient outdoor sprinkling systems.

Power generators could develop their own programs or join together with other power producers in a consortium to implement a program. Customers could be rewarded with financial incentives such as reduced costs per unit for reduced levels of usage and/or lesser rates for power used at off-peak times of the day or week. Conservation credits could be traded as in the pollution credit trading program as long as the caps were reduced each year until the overall goal for that customer base is met.

A web site devoted to success and failure of conservation incentive programs, publicizing the progress of each power plant could impact compliance by affecting shareholder decisions, among other things. The American Council for an Energy Efficient Economy has a start on this with their study 'Exemplary Utility-Funded Low-Income Energy Efficiency Programs' (www.aceee.org).

The burden of this requirement would be on the power generators and indirectly on the customer base. The goals for each power generating plant should be aggressive but attainable for their customer base. When a plant has multiple customer bases, appropriate goals should be set for each base separately, in consideration of differences in climate.

II. Description of how to implement

This rule should be mandatory for all power generators. Many power generators have such programs now but should be required to look at best practices (most cost-effective programs) for these programs and implement them.

A loan-incentive program may be needed to help owners of large buildings replace costly appliances such as hot water heaters, refrigerators, heating and air conditioning units, which can achieve high energy savings.

III. Feasibility of the option

Technical: Programs motivating conservation exist.

Environmental: The environmental benefits include reduced pollution which accompanies reduced power generation relative to what it would have been either at peak times or over time, depending on success of customer conservation program. Over time fewer power generating facilities would need to be built (or older inefficient units could be retired sooner)
Economic: Programs will cost money, but they are cost-effective (see data below). Implementation could be contracted out
Political: Probably minimal challenge in getting this requirement passed, this is pretty innocuous; and the public relations campaign around conservation would educate consumers as to their role and potential impact on reducing greenhouse gases, reducing air pollution and improving air quality

IV. Background data and assumptions

(1) Southwest Energy Efficiency Project (SWEEP): Highlights taken from SWEEP's website, http://www.swenergy.org/factsheets/index.html:

The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest examines the potential for and benefits from increasing the efficiency of electricity use in the southwest states of Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. [Unfortunately, California is not included.] The study models two scenarios, a "business as usual" Base Scenario and a High Efficiency Scenario that gradually increases the efficiency of electricity use in homes and workplaces during 2003-2020.

Major regional benefits of pursuing the High Efficiency Scenario include:

- Reducing average electricity demand growth from 2.6 percent per year in the Base Scenario to 0.7 percent per year in the High Efficiency Scenario;
- Reducing total electricity consumption 18 percent (41,400 GWh/yr) by 2010 and 33 percent (99,000 GWh/yr) by 2020;
- Eliminating the need to construct thirty-four 500 megawatt power plants or their equivalent by 2020;
- Saving consumers and businesses $28 billion net between 2003-2020, or about $4,800 per current household in the region;
- Increasing regional employment by 58,400 jobs (about 0.45 percent) and regional personal income by $1.34 billion per year by 2020;
- Saving 25 billion gallons of water per year by 2010 and nearly 62 billion gallons per year by 2020; and
- Reducing carbon dioxide emissions, the main gas contributing to human-induced global warming, by 13 percent in 2010 and 26 percent in 2020, relative to the emissions of the Base Scenario.

These significant benefits can be achieved with a total investment of nearly $9 billion in efficiency measures during 2003-2020 (2000 $). The total economic benefit during this period is estimated to be about $37 billion, meaning the benefit-cost ratio is about 4.2. The efficiency measures on average would have a cost of $0.02 per kWh saved.

The High Efficiency Scenario is based on the accelerated adoption of cost-effective energy efficiency measures, including more efficient appliances and air conditioning systems, more efficient lamps and other lighting devices, more efficient design and construction of new homes and commercial buildings, efficiency improvements in motor systems, and greater efficiency in other devices and processes used by industry. These measures are all commercially available but underutilized today. Accelerated adoption of these measures cannot eliminate all the electricity demand growth anticipated by 2020 in the Base Scenario, but it can eliminate most of it.

(2) US Department of Energy – Energy Efficiency and Renewable Energy, a consumer's guide: http://www.eere.energy.gov/consumer/ List of suggestions for consumers includes many of the items mentioned in SWEEP's High Efficiency Scenario and focuses on proper operation of the items.

V. Uncertainty

No uncertainty about benefits of conservation; moderate uncertainty about how much consumers will cooperate and actually conserve.

VI. Level of agreement TBD.

VII. Cross-over issues

Need discussion as to how it would fit into Oil and Gas Group's sources

Mitigation Option: Outreach Campaign for Conservation and Wise Use of Energy Use of Energy

I. Description of the mitigation option

Conservation is an important strategy for mitigation air pollution in 4 Corners area. An outreach campaign centered on this strategy would help to educate public and industry and lead to more conservation actions. This would lead to a sustainable future, reduce dependence on fossil fuels, and help to mitigate air pollution in the Four Corners area.

Conservation is defined as the sustainable use and protection of natural resources including plants, animals, minerals, soils, clean water, clean air, and fossil fuels such as coal, petroleum, and natural gas. Conservation makes economic and ecological sense. There is a global need to increase energy conservation and increase the use of renewable energy resources.

Coal fired power plants are the nation's largest industrial source of the pollutants that cause acid rain, mercury poisoning in lakes and rivers and global warming. Utilizing renewable energy sources such as wind and solar and improving energy efficiency in appliances, business equipment, homes, buildings, etc. will theoretically reduce pollution from coal fired power plants. Of course, installation of best management pollution control equipment on existing coal fired power plants will be most beneficial.

Renewable energy alternatives such as solar, water, and wind power and geothermal energy are efficient and practical but are underutilized because of the availability of relatively inexpensive nonrenewable fossil fuels in developed countries. Conservation conflicts arise due to the growing human population and the desire to maintain or raise the standards of living.

Up until now, consumer behavior has been motivated by cheap and plentiful energy and not much thought has been given to the degradation of the environment. Production and use of fossil fuels damage the environment. The supply of nonrenewable fossil fuels is limited and is rapidly being used up. Fossil fuel is becoming more expensive. Reality is beginning to set in. There is a need for safe, clean energy production, renewable energy alternatives, and conservation. Energy supplies and costs will restructure consumer usage.

Federal and State agencies and the utility companies need to focus on more public awareness and provide information on available tax credits for solar, photovoltaic, and solar thermal systems. There are also tax credits available to homeowners for replacement of older air conditioners, heat pumps, water heaters, windows, and installation of insulation. There are tax incentives for the purchase of hybrid automobiles.

All of this information is available on web sites, tax forms, agency handouts, etc. but, more than likely, the average citizen is unaware. Since alternative energy and conservation have moved to the forefront, the public needs information. Public service announcements on TV, radio and newspapers and informational mailings in consumer energy billings would be most helpful.

School children should be included in the energy information process. There is a program for grades K - 4 titled "Energy for Children - All about the Conservation of Energy" with a teacher's guide that is available on www.libraryvideo.com.

The educational programs need to start in elementary school (or earlier) and continue through high school. There are some really great opportunities for curriculum development in energy conservation that would integrate several disciplines including biology, math, and social studies. I think NM has done the best job of this among the four corner states and hope that it will be expanded to the other states. It would be good just to have a group review K-12 materials, see what gaps exist and how information, including successes can be promulgated. Perhaps this has been done - a web site is a good start.

A Google search of "conservation of energy resources" has a very large website database.

Volunteer groups are working to improve the energy efficiency of homes occupied by the elderly and by people who are unable and/or cannot afford to make home improvements.
Communities could work toward increasing the volunteer workforces and the resources for this much needed humanitarian service.

The future belongs to our children and grandchildren. What we have done in the past and what we do in the here and now, has a direct impact on the environment that future generations will inherit.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary at grassroots and governmental levels
Some mandatory curriculum could be developed for schools as part of educational component

B. Indicate the most appropriate agency(ies) to implement
Local Governmental Energy and Air Quality Agencies. Schools

III. Feasibility of the option
A. Technical: We must clearly demonstrate the problems and potential solutions

B. Environmental: Conservation has been shown to reduce energy use

C. Economic: Outreach program must demonstrate the short term economic benefits. Also design program to benefit low-income citizens. Government needs to provide some economic incentives to help kick start conservation programs

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups All Work Groups.

CROSSOVER OPTIONS

Mitigation Option: Bioenergy Center

(Reference as is from Power Plants: see Future Power Plants section)

Mitigation Option: Biomass Power Generation

(Reference as is from Power Plants: see Future Power Plants section)

Mitigation Option: Utility-Scale Photovoltaic Plants

(Reference as is from Power Plants: see Future Power Plants section)

ENERGY EFFICIENCY, RENEWABLE ENERGY AND CONSERVATION: PUBLIC COMMENTS

Energy Efficiency / Renewable Energy / Energy Conservation Public Comments

Comment	Mitigation Option
Advanced metering for home owners will not work. It will only enrich the electric companies who will use the data to set rates higher when people need the energy. An alternative is rolling blackouts on house AC's like that used in the Houston, TX area.	Advanced Metering
Using combined heat and power could be an effective method to increase efficiency and reduce emissions.	Cogeneration/Combined Heat and Power
The Four Corners region has a huge potential to develop renewable energy resources. Moreover, our resources are not limited to good sun and the region's many windy plateaus. Our citizenry possesses a large body of technical expertise, many of whom already work in energy and electrical power generation. We also have mechanical expertise and a pre-existing industrial infrastructure at our hands. Last, we are extremely well-suited to implement educational programs for renewable energies. Dineh College, San Juan College, and Fort Lewis College are obvious examples. This option can also sustain us beyond the inevitable decline in oil and gas production, as well as providing a means for younger generations to stay and work in their home areas (which is especially problematic in La Plata County.) Last, this possibility fits neatly with the previous recommendation for a regional planning board or authority. In short, we have every reason in the world implement renewable energy as a regional industry.	Renewable Energy
Pure protectionism, not good energy policy. The NIMBY attitude will never solve problems. If you want clean energy, do it the right way, build nuclear. I notice that this option never came up why?	Four Corners States Adopt California Standards for Purchase of Clean Imported Energy
Not only do we need net metering with our local utility (Farmington Electric Utility System), it needs to be encouraged and not expensive to sign up. These are small steps toward diversifying our energy sources, and we are in a prime solar area for generating home-based electricity.	Net Metering for Four Corners Area
A net metering program would be positive if implemented with the proper subsidies to encourage citizens to get involved. Many people in the Four Corners area are not in the financial position to invest in the start up program; this would have to come from state government programs for those who qualify.	Net Metering for Four Corners Area

Cumulative Effects

Cumulative Effects: Preface

Overview

The Cumulative Effects work group was charged with assisting the source work groups to understand current and future air quality conditions in the region, using existing information. The cumulative effects workgroup was also to assist the other work groups in performing their analysis of the mitigation strategies being developed, within the scope of the Task Force's timeframe and resources. The Cumulative Effects work group was also tasked with suggesting ways for filling technical gaps and addressing uncertainties as identified by the other work groups.

The Cumulative Effects work group was a small group with approximately a half dozen active members representing state governments, tribal governments, local citizens, industry, and the federal government.

Scope of Work

The following was the original scope of work for the Cumulative Effects (CE) work group.

Specific Tasks:

1. Evaluate air quality effects of candidate mitigation measures as requested by other Task Force work groups, or provide guidance on how candidate mitigation measures could be evaluated.
2. Prepare overarching cumulative estimate of the air quality effects from implementation of all the Task Force recommended mitigation measures.
3. Describe a "gold standard" for the best technical analyses that can be done, and provide recommendations for future analyses. Describe the uncertainty associated with the air quality estimates.
4. Respond to issues referred to the CE work group from other work groups.
5. Recommend additional analysis, studies, etc. that may be necessary for the CE work group to fully carry out its tasks. For example, the CE may feel that it is necessary to conduct an ozone precursor field study with advice from the monitoring group, or an ammonium field study for particulate matter.

Discussion

In accomplishing #1, the Cumulative Effects work group was charged with assessing upwards of 20 of the numerous mitigation options being proposed by the source-related work groups. For these options, the emissions reductions associated with undertaking the mitigation approach have been estimated. In addition, the work group also detailed methods, assumptions, limitations, and sources of information.

All of the tasks associated with estimating emissions reductions were relative to the oil and gas sector. In order to make much of this work as accurate as possible, the Cumulative Effects work group undertook improvements to the base case inventory for drilling and production activities in the Four Corners region. The base case inventory shows what current and future emissions would be in the absence of additional air pollution mitigation. The best data from the Western Regional Air Partnership (WRAP), the States of New Mexico and Colorado, the Southern Ute Indian Tribe, and industry participants were consolidated and quality assured to create a more accurate and complete inventory than previously existed. Using estimates of the effectiveness of the various mitigation options and applying them to the base case, estimates of the number of tons of pollution that would be reduced by each mitigation option were calculated. Emissions reductions associated with mitigation options directed and motor vehicles used in oil and gas activities were also estimated.

Because of the length of time and resources required to set up modeling analyses and to accomplish them, the modeling task (#2) was moved outside the Task Force process. It will inform regulatory agencies of the air quality benefits of options after the Task Force report is completed. The approach taken is akin to the "gold standard," and thus #3 was addressed as part of the agencies' modeling effort.

Consistent with #4, the Cumulative Effects work group also responded to requests for additional information relative to a few of mitigation options, for example, answering questions about monitoring at a power plant and providing a bit more detailed description of overall emissions.

Related to #5, suggestions for future research associated with implementation of the mitigation options are presented, for example, with regard to the sources and impacts of ammonia emissions and the economic effect of various mitigation option

OVERVIEW OF WORK PERFORMED

The Cumulative Effects (CE) work group was requested to provide information on a number of mitigation options described by the source work groups. Table 1 summarizes the reasons why the Cumulative Effects work group may or may not have researched a particular question, and a brief description of the outcome if work was performed.

Table 1: Summary of mitigation option findings.

OPTION	ACTION TAKEN BY CE	SUMMARY OF RESULT
Tax or Economic Incentives for Environmental Mitigation	CE did not have expertise to address this option.	No action.
Selective Catalytic Reduction (SCR) on Drilling Rig Engines	There was insufficient time to address this option.	Some data exists on drilling emissions. The State of Wyoming evaluated this technology based on a pilot study in the Jonah Field & concluded that is not a cost effective technology, but further analysis is needed.[1]
Implementation of EPA's Non Road Diesel Engine Rule – Tier 2 through Tier 4 Standards for Drilling Rigs	There was insufficient time to address this topic.	An important piece of information is that these engines typically last 4-10 years and then need to be replaced. This means that there will be a constant infusion of new technology engines over time. However, faster turnover would reduce emissions in the near-term.
Industry Collaboration for RICE	This option was not evaluated because it is not possible to quantify emission reductions.	No action.
Install Electric Compression for RICE	This option was evaluated.	Replacement of low emission engines with electric power grid would result in an overall increase in emissions. A reduction in NOx emissions would occur, however, there would be an increase greenhouse gas emissions due to increased electrical generation requirements.
Follow EPA Proposed New Source Performance Standards (NSPS) for RICE	This option was evaluated.	This proposed emission standard will become the baseline for new modified and reconstructed engines. Future year projections indicate that these standards will minimize growth in oil and gas emissions from natural gas fired engines.
Install Selective Catalytic Reduction (SCR) on Lean Burn Engines for RICE	This option was evaluated.	There is very little information on the installation of this control technology on natural gas fired engines. What is available indicates that in the Four Corners area the installation of this technology would result in small NOx reductions. In addition, the cost to control emissions would be relatively high.[2] **Differing Opinion:** Disagree with the last two sentences.
Install Non Selective Catalytic Reduction (NSCR) on Rich Burn Engines for RICE	This option was evaluated.	It was found that installation of NSCR on small engines could reduce NOx emissions significantly. The USEPA performance standard for rich burn engines will likely require installation of NSCR for new, modified and reconstructed rich burn engines.

OPTION	ACTION TAKEN BY CE	SUMMARY OF RESULT
Install Lean Burn Engines for RICE	This option was evaluated.	Emission inventory data indicated that on large engines of greater than 500 horsepower this technology or NSCR is already being used on the majority of the engines in the region. The use of these engines results in significant reductions in NOx over the use of rich burn engines, and may be beneficial when applied to smaller engines.
Install Selective Non Catalytic Reduction (SNCR) for RICE	This option was evaluated.	It was determined that this technology is unlikely to be used because it is less effective than SCR or NSCR.
Install Oxidation Catalyst on Lean Burn Engines for RICE	This option was evaluated.	This mitigation option was evaluated in terms of HAPs emissions and VOCs. Previous modeling analyses indicated that HAPs impacts are localized. It was found that VOC emission reductions would be primarily methane and ethane which have a low photochemical reactivity, and likely do not contribute to ozone formation. **Differing opinion:** Contest the previous statement as to accuracy. Methane is a greenhouse gas and reduction of methane emissions is desirable in combating global climate change.
Install Optimized/Centralized Compression	This option was evaluated.	It was concluded that there would be no opportunities for reducing emissions as a result of implementing this option.
Next Generation Control Technology for RICE	This option was evaluated.	Because these technologies are emerging, it is not possible to quantify the additional benefits of controls.
Automation of Wells to Reduce Truck Traffic	This option was evaluated.	Potential fugitive dust emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Centralized Produced Water	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Efficient Routing of Water Trucks	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Cover Lease Roads with Rock or Gravel	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Enforcing Speed Limits on Dirt Roads	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.

OPTION	ACTION TAKEN BY CE	SUMMARY OF RESULT
Selective Catalytic Reduction (SCR) NOx Control Retrofit	This option was not evaluated.	Only emission reductions were estimated, not effects on visibility or ozone, so could be done as a part of future work.
Emissions Monitoring for Proposed desert Rock Energy Facility to be Used Over Time	This option was assessed.	The option was looked at by the CE Work Group, and an assessment included.
Declining Cap and Trade Program for NOx Emissions for Existing and Proposed Power Plants	This option was not evaluated.	Only emission reductions were estimated, not effects on visibility or ozone, so could be done as a part of future work.
Chronic Respiratory Disease Study for the Four Corners Area	A brief look at the data was done.	A summary of ozone trends generally showed an upward trend. Another look at this question will be provided by future work.
Install Electric Compression	This option was evaluated.	See above.

Emissions Summary

The overall emissions of nitrogen oxides (NOx) and volatile organic compounds (VOC) broken into broad source categories can provide some perspective when reductions from various mitigation options are presented in subsequent sections. Table 2 shows the relative importance of groups of sources in the Four Corners region:

Table 2: Percentage of total future year emissions in 2018 by pollutant.

SOURCES	NOx EMISSIONS (%)	VOC EMISSIONS (%)
Mobile	2	5
Area	1	23
Oil & Gas	26	32
Power Plants	40	1
Other Point Sources	30	39

This table demonstrates that oil and gas production, electrical generation, and other industrial activities are the largest emitters of nitrogen oxides, while oil and gas production, industrial facilities other than those related to power plants and oil and gas production, and area sources emit the majority of VOC. Area sources are those industrial and commercial activities that are small enough to not be required to obtain an air quality permit to operate. Area sources also include a broad range of human activities that result in small amounts of pollution on an individual basis.

The data presented in Table 1 have been derived primarily from the Western Regional Air Partnership (WRAP) emission inventory. For these categories, the Four Corners Air Quality Task Force requested an extraction from the WRAP regional database for the Four Corners area that encompasses portions of Colorado, New Mexico, Arizona, and Utah. The one exception is for oil and gas sources, which were estimated using updated information developed by the Cumulative Effects work group.

Emissions Reduction Summary

Table 3 summarizes emission reductions for mitigation options for which the estimates were made in order to facilitate comparison. Some estimates were made by the Cumulative Effects work group for the Oil and Gas work group, while some were made by the Power Plants (PP) work group for their own options. Descriptions of the mitigation options and how the estimates were derived can be found in the section of each work group, respectively.

Table 3: Mitigation Option Summary

Mitigation Option	Work Performed By	Pollutant Reduced	Reduction Estimate (tpy)
Control Technology Options for Four Corners Power Plant	PP	NOx	11,688
Control Technology Option for San Juan Generating Sta.	PP	NOx	6,166
Enhanced SO2 Scrubbing	PP	SO2	2,083
Selective Catalytic Reduction (SCR) NOx Control Retrofit	PP	NOx	29,987 to 46,684
BOC LoTOx System for Control of NOx Emissions	PP	NOx	43,257
Baghouse Particulate Control Benefit	PP	PM10	465
Declining Cap and Trade Program for NOx Emissions	PP	NOx	3,428
Install Electric Compression w/ Grid Power	CE	NOX & SO2	Variable – See note below
Install Electric Compression w/ Onsite Gen Power	CE	NOX & SO2	12,000 to 40,721
Use of NSCR for NOx Control on Rich Burn Engines	CE	NOx	16,588 to 21,327
Use of SCR for NOx Control on Lean Burn Engines	CE	NOx	Insufficient information to quantify
NSPS Regulations	CE	NOx	0
Optimization/Centralization	CE	NOx	0
Use of Oxidation Catalyst for Formaldehyde & VOC Control on Lean Burn Engines	CE	VOC	1619
Automation of Wells to Reduce Truck Traffic	CE	PM10 & NOx	196 & 92
Reduced Truck Traffic by Centralizing Produced Water Storage	CE	PM10	39
Reduced Truck Traffic by Efficiently Routing Produced Water Disposal Trucks	CE	PM10	196
Reduced Vehicular Dust Protection by Covering Lease Roads with Rock or Gravel	CE	PM10	206
Reduced Vehicular Dust Production by Enforcing Speed Limits	CE	PM10	73

Note: Some engine configurations are as efficient as current coal-fired generating stations without being subject to line losses, whereas other engines would be less efficient than using commercially available line power.

Suggestions for Future Work

As the Cumulative Effects work group completed the tasks of evaluating mitigation options, it became clear that there is a need for future work to provide regulatory agencies additional information on the benefits of reducing pollution emissions into the air in the Four Corners region. Additional detailed modeling is planned by the agencies that will provide more refined information regarding the actual effects of proposed mitigation programs. The modeling analysis is scheduled for completion in the fall of 2007. Leading into the analysis of mitigation programs, some updating of source information will be necessary. An example would be for drilling rigs.

To supplement the modeling analyses, additional monitoring of pollutants and meteorology throughout the Four Corners region would be useful. This monitoring would provide a basis for establishing whether model predictions are accurate and would help determine air quality trends. Currently, there are relatively few air monitoring sites in the Four Corners region to use in testing model performance. Monitoring for ammonia would be particularly useful as it enhances the ability of the model to estimate the effects of air pollutant emissions on visibility.

The Cumulative Effects work group was required to delve into agency emissions inventories in detail, and this work exposed many weaknesses in state and tribal inventories. For future analysis of options, it is recommended that states and tribes require more robust reporting of industrial entities, including reporting of facilities that may currently fall below permitting or reporting thresholds. States and tribes may require regulatory changes to reporting requirements to accomplish this. Lack of detailed reported data introduces a high level of uncertainty into analysis of options for mitigation. State and tribal agencies need to be able to quantify cumulative reductions with certainty in order to appropriately evaluate and prioritize options. By performing analyses that combine trends in emissions with trends in monitoring data, information may be identified regarding source receptor relationships.

The work group also recommends a review of existing field test data and an expansion of the existing state and tribal field testing programs for source emissions. Improvement of inventory emissions estimates will result in better modeled estimates of air pollution concentrations. A focused effort to obtain and share emissions data from a variety of oil and gas engines under different operating conditions would be particularly beneficial in inventory improvement.

Finally, the work group recommends that economic analysis of options be conducted to provide cost/benefit information to state and tribal agencies. The work group did not have the time or resources to conduct economic modeling, but economic data is of great importance in analyzing and prioritizing options. Such modeling could analyze "bundled" options to minimize analysis costs.

Endnotes:

1 Personal communication between Reid Smith (BP) and David Finley (WDEQ).

2 EPA Speciate data for natural gas-fired engines.

DETAILED DESCRIPTIONS OF MITIGATION OPTION ANALYSES

Mitigation Option: Install Electric Compression with Grid Power

Description of Option
Under this option, existing or new natural gas fired internal combustion engines would be replaced with electric motors for powering compressors. Electric motors would be selected to deliver equal horsepower to that of the internal combustion engines being replaced.

Assumptions
It is assumed that electricity to power the electric motors would come from the existing electrical grid. The majority of the base load electricity in the region is produced from coal-fired electrical generation.

This option did not consider the installation of natural gas electrical generation systems, which would have entirely different emissions characteristics from coal-fired electrical generation. In this approach, small high-emission natural-gas engines would be replaced by electric motors driven by a larger low-emission natural-gas engine. Although natural gas fired generators have not been used in the region, the feasibility for possible future use should be investigated. [1]

In evaluating the changes in emissions for shifting from natural gas to electric (coal) powered compression, it is necessary to examine the emissions for each power source on an equivalent energy basis. Thus, for the same amount of energy consumption, the change in emissions from natural gas versus electricity must be considered.

In the evaluation of this mitigation option, it is not appropriate to consider emission modifications to existing electrical generating facilities. While such modifications may occur or new lower emitting facilities may be developed, the inclusion of such changes in emissions are speculative at this point in time. The emission data was developed using the EPA program EGRID. [2]

In this analysis, it was assumed that for visibility SO2 and NOx emissions are equivalent in terms of impacts because they cause approximately the same amount of visibility impairment. This is because the dry scattering coefficients for converting SO4 and NO3 concentrations into visual range are approximately equivalent. NOx emissions do participate in photochemical reactions that produce ozone.

However, ozone modeling analyses performed by the state of New Mexico as part of the Early Action Compact (EAC) and ozone monitoring data in the area suggest that ozone formation is VOC limited and consequently NOx emission reductions may cause increases in ozone concentrations. Both SO2 and NO2 ambient concentrations are in compliance with federal and state air quality standards.

As a first order approximation, 1 ton per year of SO2 emissions will result in the same amount of potential visibility impairment as 1 ton per year of NOx. In reality, because of the more complex and competitive reactions involving both SO4 and NO3, SO2 emissions may result in more visibility impairment than NOx emissions.

From an economic basis, conversion of natural gas-fired engines to electric compression is only practical for large engines and only in areas where electricity is already available within close proximity. This is because most locations do not currently have electrical power and it would not be cost effective to install power for small engines.[3]

In Colorado, most large engines (greater than 500 hp) are lean burn or have NSCR installed to reduce emissions (average emission factor for this size engine is 1.4 g/hp-hr). In addition, any new engines in this size category must achieve an emission limit of 1 g/hp-hr.[4] These engines are typically located at remote sites where power is not available.

In New Mexico, for large engines (greater than 500 hp) the average emission factor is 3.0 g/hp-hr. There are a total of 354 engines in this size category.[5] Of that total, 221 engines have NOx emission less than or equal to 1.5 g/hp-hr (62 percent), 108 engines have NOx emissions in the range of 1.6 to 5 g/hp-hr (31 percent) and 25 engines have NOx emissions greater than 5 g/hp-hr (7 percent). Under a recent BLM EIS Record of Decision (ROD), new engines must achieve 2 g/hp-hr.

Method

The energy consumption of a typical lean burn engine was calculated, converted into pounds per mega watt-hour and was compared to SO2 and NOx emissions from existing coal-fired power plants. This was done assuming an emission factor between 1 g/hp-hr and 5 g/hp-hr. It was then assumed that the computed emissions per mega watt of power represented emissions for 1-hour and were converted into tons per year by multiplying by 8760 hours per year and dividing by 2000 pounds per ton.

As indicated in Table 4, a shift from natural gas to electric (coal) for an engine of 1 MWhr capacity (approximately 1,342) hp with an emission factor of 1 g/hp-hr would result in an **increase** of 14 tons per year of SO2 + NOx. With engine emissions of approximately 2.0 g/hp-hr there is no net change in overall emissions by shifting from natural gas to electric. For all cases, the shift from natural gas to electricity results in higher greenhouse gas emissions.

Conclusions

NOx emissions from large engines in Colorado and the remaining engines in New Mexico are currently controlled at sufficient levels so that shifting from natural gas to electric compression may only result in a small reduction in emissions and in many cases would result in an increase in SO2 and NOx emissions.

For all categories of engines, greenhouse emissions would increase by shifting compressors from natural gas to electric.

Table 4: Change in SO2, NOx and Greenhouse Gas Emissions by Shifting from Natural Gas Compression to Electricity

Four Corners Grid Average Emissions lbs/MWh		tons/MWh/yr
SO2	2.65	11.6
NOx	3.64	15.9
NOx + SO2	6.29	27.6
CO2	1,989	8711.8

Table 4A: Example Engine Changes

Caterpillar 3608 LE Average Emissions lbs/MWh (equivalent)		Other Emission Rates (gr/hp-hr)				
SO2	0	0	0	0	0	0
Hp/kw-hr	1.342	1.342	1.342	1.342	1.342	1.342
Hp/mw-hr	1,342	1,342	1,342	1,342	1,342	1,342
Cubic feet gas/mw-hr	9,815	9,815	9,815	9,815	9,815	9,815
NOx Emission Rate gr/hp-hr	1	2	3	4	5	16
SO2 lbs/mw-hr	0	0	0	0	0	0
NOx lbs/mw-hr	3.0	5.9	8.9	11.8	14.8	47.3
CO2 lbs/mw-hr	1,138	1,138	1,138	1,138	1,138	1,138
SO2 tons/MWh/yr	0.0	0.0	0.0	0.0	0.0	0.0
NOx tons/MWh/yr	13.0	25.9	38.9	51.8	64.8	207.4
CO2 tons/MWh/yr	4985	4985	4985	4985	4985	4985
Delta SO2 tons/Mwh/yr	11.6	11.6	11.6	11.6	11.6	11.6
Delta NOx tons/Mwh/yr	3.0	-10.0	-22.9	-35.9	-48.9	-191.4
Delta NOx +SO2 tons/MWh/yr	14.6	1.6	-11.3	-24.3	-37.3	-179.8
Delta CO2 tons/Mwh/yr	3727	3727	3727	3727	3727	3727
Cat. 3608 Assumptions: 9815 Btu/kw-hr "Sweet" Natural Gas NOx - 1 gr/hp-hr 1 cu ft gas = 1,000 btu						

Endnotes:

[1] Factors that need to be considered for use of a natural gas fired electrical generation system are: engines must be located in clusters that lend themselves to being interconnected by power lines; generator and line reliability need to be evaluated; the efficiency of electrical generators systems compared to natural gas fired compression must be evaluated; it needs to be determined if natural gas fired electrical

generators have substantially lower emissions than new natural gas fired compressor engines; cost and the benefits of this analysis need to be evaluated in terms of potential ambient air quality benefits, not simply emission reductions.

[2] EPA EGRID Program http://www.epa.gov/cleanenergy/egrid/index.htm

[3] The quantification of changes in emissions of this option does not address the cost of implementation or the reliability of the electrical grid. These issues must be considered if this option is deemed beneficial from an environmental perspective.

[4] Northern San Juan EIS Record of Decision (April 2007)

[5] NMED Part 70 permits, Minor source permits and Environ inventory.

Mitigation Option Analyses: Replace RICE Engines with Electric Motors for Selected Oil and Gas Operations (Alternative 2 – Power Source: On-Site Natural Gas-Fired Generators)

Description of Analysis of the Alternative Option

As an alternative to grid power, dedicated on-site, natural gas-fired, electrical generators can be used to supply power to electric motors suitable for selected replacement of "dirty" compression and other E&P RICE engines. This alternative to the Install Electric Compression (Grid Power Alternative) expands candidate engines for replacement beyond compressor engines since some existing compressor engines, particularly in the Northern San Juan Basin, are already well controlled. The electric motors are rated on an equivalent horsepower basis to RICE engines targeted for replacement. This analysis covers both the top 25 "dirtiest" and all essentially uncontrolled, primarily small, rich burn engines, with emissions greater than 4 g/hp-hr. Net NOx and CO emission reductions are reported in mass emission rates (tons/yr) and normalized mass emission rates (tons/yr/MW).

Assumption

The currently available gas electric generators run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural gas and field gas. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. The calculated net reduction in emissions from existing RICE engines to electric motors powered by on-site electric generators were done based on an equivalent power basis.

In order to implement this option an electrical infrastructure would need to be constructed between the locations of the gas fired generator and the electric compressors. In addition, a control system would have to be developed so that as the engine load (demand) varies the generator supply would be adjusted to meet the demand. In order to implement this option it may be necessary to connect the generator to the power grid so that excess electricity could be utilized. Several engine companies manufacture gas electric generators. We assumed use of a mid-size Caterpillar gas electric generator as the reference natural gas on-site generator for calculating the net emissions for this alternative (not to be construed as an endorsement). The Caterpillar G3612 gas electric generator with power rating of 2275 kW emits 0.7 gram/hp-hr NOx and 2.5 g/hp-hr CO. It is important to note that the emissions from such generators are not different than what can be achieved from a lean burn engine (available with a capacity in excess of 500 hp) and not appreciable different emissions from new NSPS engines.(2 g/hp-hr vs 0.75g/hp-hr).

The selection of RICE engines for electrification analysis did not consider important factors that would need to be weighed in determining the degree of implementation that might be feasible. This would include the locations and spatial distribution of engines (e.g., proximity of with each other), the number and cost of required on-site generators, maximum transmission line lengths and any ROW issues, number of electric motors and costs, and operational and environmental factors.

Available engine inventories, for producers in New Mexico and Colorado (e.g., bp) were combined in order to obtain a representative engine inventory for the San Juan Basin.

Method

The NOx and CO emission of the reference Caterpillar G3612 generator were given in g/hp-hr which was converted into lbs/MW-hr by multiplying the (1,342 hp/MW) and divided by (454 gm/lbs). Further, the NOx and CO emissions in tons/yr/MW units were obtained by multiplying 8760 hrs/yr and dividing by 2000 lbs/ton. The NOx and CO emission factors and calculated normalized emission rates for NG generator are given in Table 5.

Table 5: Gas Electric Generator Emissions

2,275 kW			
	(g/hp-hr)	(lbs/MWh)	(tons/yr/MW)
NOx	0.70	2.07	9.06
CO	2.50	7.39	32.37

The net emission reduction was first calculated for the replacement the 25 worst NOx emitters and compared with a greater subset of replaced engines (e.g., engines emitting more than 4 g/hp-hr engines). The selection of the 25 worst engines is based on potential tons/yr NOx emission of individual engines. The potential engine emission calculation assumes 100% load and 8760 hrs operation per year. Engine emission factors were obtained by combining the New Mexico and Colorado engine inventory database used the Alternative 1 analysis.

The following illustrates how the mass emission rates (ER) and normalized mass emission rates (NER) were calculated for each engine size group.

EF (24.6 g/hp-hr) * Engine Size (1,350 hp) * (# of engines) * (8,760 hrs/yr) * (1/454g/lbs) * (1/2,000 lbs/ton) = 320.4 (tons/yr)

EF (24.6 g/hp-hr) * (1,342 hp/MW) * (8,760 hrs/yr)*(1/454g/lbs)*(1/2,000 lbs/ton) = 318.5 (tons/yr/MW)

The 25 engines with the highest mass emission rates in the combined inventory were identified. The total power of these was obtained by adding the rated power of individual engines, which was used to calculate equivalent emission from gas generator needed to run the 25 electric motors replacing the replaced RICE engines. For the case of the 25 highest emitting engines, the average capacity is 684 hp, the maximum capacity is 2,400 hp and the lowest capacity is 325 hp. What is important about the capacities is that for the majority of these engines lean burn engines are available. Table 6 shows the normalized average emissions in tons/yr/MW as well as net potential mass emission reductions for both NOx and CO emission based on the 25 worst NOx emitters. The average emission factor for the top 25 engines is 23.9 g/hp-hr.

Table 6: Emission change if 25 worst NOx emitting engines retired

Total rated power = 17,108 hp = 12.8 MW		
	NOx	
	Avg. NER (tons/yr/MW)	Total ER (tons/yr)
Caterpillar G3612	+9.06	+115.51
Worst 25 Engines	-251.21	-3,106.40
Net Reduction	-242.14	-2,990.89

Table 7 shows the same calculations based on all the engines emitting more than 9 g/hp-hr.

Table 7: Emission change if all engines emitting > 4g/hp-hr NOx retired

2925 engines with total rated power = 233,278 hp = 205.7 MW Emitting > 9 g/hp-hr NOx		
	NOx	
	avg/engine (tons/yr/MW)	Total (tons/yr)
Caterpillar G3612	9.06	1,863.75
All engines emitting more than 4.0g/hp-hr	211.36	40,562.21
Net Reduction	-202.30	-38,698.45

Conclusion

A net reduction of approximately 2,991 tons/yr of NOx can be achieved if the 25 engines with the highest NOx mass emission rate t operating in the San Juan Basin are replaced with nine 2 MW well controlled on-site natural gas electrical generators. Although most large RICE engines operating in the San Juan Basin are relatively small emitters individually and collectively, a significant number of small and medium range engines are not controlled well and collectively represent a relatively large E &P emission source group. The analysis in this alternative reveals a potentially significant emission reductions are possible for this group of engines. The calculation of emission reduction for replacing all the engines emitting more than 9.0 g/hp-hr NOx (over 2925 engines) with electric motors powered by several similar natural gas generators show that 38,698 tons/ per year of NOx reduction might be achieved by this option. This level of replacement would require approximately 90 on-site generators rated at 2 MW.

The potential emission reductions presented in this analysis assume optimal mitigation option implementation conditions which may not be nearly as optimistic if more detailed data were available and factored into the analysis. The selection of engines for electrification analysis did not consider important factors that would need to be weighed in determining the option feasibility and what degree of implementation would be possible. Factors such as the locations and spatial distribution of engines and operational and environmental issues would need to be considered. These and other factors would need to be carefully evaluated to better quantify the effectiveness of this alternative in terms of potential emission reductions achievable and certainly in quantifying implementation costs.

References

1. The emission and power information for the Caterpillar G3612 Gas Generator was obtained from Caterpillar's website. www.cat.com.

2. The engine inventory for NM and CO used to calculate emission reduction was provided by BP America, which includes contributions from: BP, New Mexico Environment Department, Colorado Dept. of Public Health & Environment and ENVIRON

Mitigation Option: Use of NSCR for NOx Control on Rich Burn Engines

Description of the Option

NO_X, CO, HC, and formaldehyde emissions from a stoichiometric engine can be reduced by chemically converting these pollutants into nitrogen, carbon dioxide and water vapor. The most common method for achieving this is through the use of a catalytic converter. In a catalytic converter, the catalyst will either oxidize (oxidation catalyst) a CO or fuel molecule or reduce (reduction catalyst) a NO_X molecule.

A process which causes reaction of several pollutant components is referred to as a Non Selective Catalyst Reduction (NSCR) and is applicable only to stoichiometric engines. Engines must operate in a very narrow air/fuel ratio (AFR) operating range in order to maintain the catalyst efficiency. Maintaining low emissions in a stoichiometric combustion engine using exhaust gas treatment requires a very closely regulated air/fuel ratio. Without an AFR controller, emission reduction efficiencies will vary. Most AFR controllers utilize closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

An AFR controller will only maintain an operator determined set point. For this set point to be at the lowest possible emission setting, an exhaust gas analyzer must be utilized and frequently checked.

Some issues associated with current practice NSCR retrofits on existing small engines operating at reduced loads are:

- a problem maintaining sufficient flue gas inlet temperature for correct oxygen sensor operation and the resulting effectiveness of the catalysts
- On engines with carburetors, there is difficulty maintaining the AFR at a proper setting
- On older engines, the linkage and fuel control may not provide an accurate enough air/ fuel mixture
- If the AFR drifts low (i.e., richer), ammonia formation will increase in proportion to the NOx reduction but not necessarily in equal amounts.

The first issue can be mitigated by retarding the ignition timing when the engine operates at reduced loads. The retarded ignition timing reduces NOx emissions and also raises the flue inlet temperature which helps maintain the catalyst efficiency. Eliminating or mitigating the second, third, and fourth issues require a closed-loop feedback control with an exhaust oxygen sensor to continuously adjust the AFR. One way of doing this is to adjust the carburetor so it operates slightly lean and use the feedback control to adjust the amount of supplemental fuel supplied to a port downstream of the carburetor. Worn carburetors and linkages should be replaced as a maintenance issue.

Assumptions

Currently, recent EIS RODs in Colorado and New Mexico require performance standards for new or replacement engines that will accelerate the implementation of the 2008 and 2010 federal NSPS for non road engines. Most engines in the 4 Corners Region in excess of 500 hp are lean burn engines and that trend is expected to continue in the future. These engines meet low emission standards through lean burn combustion technology and NSCR catalyst cannot be installed on this type of source. Therefore, the implementation of NSCR technology would have little or no effect on emission levels for new or replacement engines in excess of 500 hp. New or replacement engines having capacities of less than 500 hp and 300 hp will be required to meet an emission limit of 2 g/hp-hr in Colorado and New Mexico, respectively. Because of the limited availability of lean burn engines in this size range, NSCR will have to be used to achieve the prescribed emission levels. Thus, it is very likely that new or replacement engines will use this technology and there will be no additional possible NOx emissions reductions. It is important to note that a properly designed and operated NSCR system can achieve emission levels less than 2 g/hp-hr. However, the question becomes one of maintaining emissions at lower levels on a continuous basis and the operator's need to have a safety factor for ensuring continuous compliance with source emission limits. Thus, on average, actual emissions will be less than the prescribed regulatory limits, however, there will be times when emissions will approach the regulatory limit.

In examining additional NOx mitigation (beyond current regulatory drivers), NSCR would be applicable to existing rich burn engines that have a capacity of less than 500 hp.

In order for NSCR technology to result in any reduction of NOx emissions in the 4 Corners Region, it would have to be implemented on existing engines less than 500 hp. Estimates of potential emission reductions were calculated for engines in the range of 300 to 500 hp, 100 to 300 hp and between 75 hp and100 hp. Currently, there is no single retrofit kit that can be installed on existing engines. Even if an air fuel ratio controller with an oxygen sensor were installed, it is uncertain if the carburetor linkage would allow an accurate and precise enough control required to maintain the proper air fuel mixture without repair or upgrade.

However, compliance data (unannounced tests) obtained from the SCAQMD for 215 retrofitted rich burn engines show that over 90% of these engines, with installed AFRC, were able to meet or do better than 2 g/hp-hr. Six engines were essentially uncontrolled due to lack of any installed AFRC. Over 77% of the tested engines did better than 1 g/hp-hr (SCAQMD, 2007).

Engine Size >300 hp and < 500 hp

The uncontrolled NOx emission factor for existing rich burn engines between 300 hp to 500 hp in Colorado and New Mexico ranges from 11.4 to 21 g/hp-hr. The average emissions from the 11 rich burn engines in this size group are 18.3 g/hp-hr. The mass emission rate of a combined 3,660 hp for these engines total nearly 650 tons NOx/yr. Many of the engines in the 300-500 hp range already had some emission controls on them (such as being lean burn).

In new applications, laboratory data shows that NSCR can exceed 90% NOx reduction and in some cases possibly 95%. Because mitigation is being considered on a fleet of older existing engines, it may not be possible to achieve a 90% plus level of performance reliably in the field. Field tests to address this and other issues are being planned by Kansas State and are expected to start soon. Based on what we know now, lab data and existing compliance data from an inventory of over 200 retrofitted operating engines in southern CA., it was assumed that a well designed NSCR retrofit kit could reliably achieve NOx reduction in the range of 70% to 90%, Applying NSCR retrofits on the identified 11 "dirty engines" could reduce the NOx emissions to 1.8 tg/hp-hr (an ~ 450 tons/yr reduction) at the low end and 5.5 g/hp-hr at the high end (an ~ 590 ton/y reduction).

Engine Size > 100 hp < 300 hp

The uncontrolled NOx emission factor for existing rich burn engines between 100 hp to 300 hp in Colorado and New Mexico ranges from 15 to 24 g/hp-hr. The average emissions from the 240 rich burn engines in this size group are 19.1 g/hp-hr. The mass emission rate of the combined 38,394 hp for these engines total over 7,000 tons NOx/yr. Some engines in this size range were excluded from this group because they were identified as lean burn

Based on what we know now, lab data and existing compliance data from an inventory of over 200 retrofitted operating engines in southern CA, it was assumed that a well designed NSCR retrofit kit could reliably achieve NOx reduction in the range of 70% to 90%, Applying NSCR retrofits on the 240 identified "dirty engines" could reduce the NOx emissions to 1.9 g/hp-hr (an ~ 6,500 tons/yr reduction) at the low end and 5.7 g/hp-hr at the high end (an ~ 5,000 ton/y reduction). Not all retrofits may be operationally practical or economically feasible.

Engine Size > 75 hp and < 100 hp
The uncontrolled NOx emission factor for existing rich burn engines between 75 hp to 100 hp in Colorado and New Mexico ranges from 9.4 to 22.4 g/hp-hr. The average emissions from the 901 rich burn engines in this size group are 19.7 g/hp-hr. The mass emission rate of the combined 84,307 hp for these engines total over 11,200 tons NOx/yr. The lowest emitters are a group of Ford engines that may have EGR, but the database does not specify whether they have EGR.

Based on what we know now, lab data and existing compliance data from an inventory of over 200 retrofitted operating engines in southern CA, it was assumed that a well designed NSCR retrofit kit could reliably achieve NOx reduction in the range of 70% to 90%, Applying NSCR retrofits on the 900 identified "dirty engines" could reduce the NOx emissions to 5.9 g/hp-hr (an ~ 11,200 tons/yr reduction) at the low end and 2.0 g/hp-hr at the high end (an ~ 14,400 ton/y reduction). Not all retrofits may be operationally practical or economically feasible.

There is considerable uncertainty in the NOx reduction in these engines, which tend to be older than the engines in other size ranges. Attention to worn linkages and carburetor parts as well as closed-loop AFR control is expected to be necessary if these engines are to achieve effective NOx reduction.

Additional long term testing of the use of NSCR on existing small engines must be performed prior to any large scale implementation of this option. Currently, testing is beginning that will address the field application of this technology for retrofit conditions on rich burn small engines..[1]

Method
A spreadsheet containing the combined engine inventories for Colorado and New Mexico was developed. For each of the three size ranges of interest, a new database was created in which engines outside the size range of interest were deleted. Each of the three newly created databases were further modified by deleting all engines that are identified by their model designation as "lean-burn" and by deleting all remaining engines whose NOx emissions are 5.0 g/hp-hr or less. The resulting three databases contain only rich-burn engines in the size ranges of interest. Overall NOx emissions were totaled for each of the three size ranges, and emissions reductions of 70% and 90% were applied. resulted in a reduction in NOx emissions of 723 tons per year (a 7 percent reduction of Colorado oil and gas emissions). The engines in the New Mexico inventory were treated similarly.

One important point is that the New Mexico inventory indicated that 1,024 engines were less than 40 hp, which is the proposed de minimus threshold in the NSPS. Under the proposed regulation, EPA concluded that control of this size engine is not appropriate or cost effective. In New Mexico this class of engines had emissions of 2,049 tons per year (i.e., each engine had emissions of approximately 2 tons per year).

Table 8 presents the projected changes in NOx emissions if NSCR were installed on existing engines in Colorado and New Mexico.

Table 8: Emission Reductions from implementing NSCR on Existing Rich Burn Engines in Colorado and New Mexico

Colorado and New Mexico, 70% Reduction - NSCR on all Existing Rich-Burn Engines

Engine Size	Reduction (%)	Average Mitigated Emission Factor (g/hp-hr)	Unmitigated Total (16-year 2018-year) Average NOx Emissions (t/yr)	NOx Reduction (t/yr)
< 500 hp Eng > 300 hp	70	5.5	3150	453
< 300 hp Eng > 100 hp	70	5.7	5948	4934
< 100 hp Eng > 75 hp	70	5.9	13317	11201
Total Reduction			**51783**	**16588**
Percent Reduction				**32**

Colorado and New Mexico, 90% Reduction – NSCR on all Existing Rich-Burn Engines

Engine Size	Reduction (%)	Mitigated Emission Factor (g/hp-hr)	Unmitigated Total (16-year 2018-year) Average NOx Emissions (t/yr)	NOx Reduction (t/yr)
< 500 hp Eng > 300 hp	90	1.8	3150	582
< 300 hp Eng > 100 hp	90	1.9	5948	6343
< 100 hp Eng > 75 hp	90	2.0	13317	14402
Total Reduction			**51783**	**21327**
Percent Reduction				**41**

Conclusions

Installing NSCR on existing engines less than 500 hp in Colorado and New Mexico would result in a reduction of approximately 16,588–21,327 tons per year of NOx over current projected emissions in 2018.

Additional field testing on the installation of retrofit NSCR on engines less than 500 hp is needed to document what level of emission control could be achieved on a continuous basis.

Detailed modeling is planned that will quantify the air quality benefit of such reductions either separately or in combination with other potential mitigation measures. For visibility, currently in the Mesa Verde and Wimenuche Class I Areas NOx emissions are a very small portion of the total extinction budget, however in recent years the trend has been flat or showed slight increases. Also, because of complex photochemical reactions involving VOC emissions and NOx emissions, changes in NOx emissions could result in localized increases or decreases in ozone. Regional effects of changes in ozone precursor emissions would need to be determined using a photochemical model.

Mitigation Option: Use of SCR for NOx Control on Lean Burn Engines

Description of the Option

Using this option, existing or new lean burn natural gas fired internal combustion engines would be installed with selective catalytic reduction (SCR). This technology uses excess oxygen in a selective catalytic reduction system. Reactant injection of industrial grade urea, anhydrous ammonia, or aqueous ammonia is required to facilitate the chemical conversion. A programmable logic controller (PLC) based control software for engine mapping/reactant injection requirements is used to control the SCR system. Sampling cells are used to determine the amount of ammonia injected which depends on the amount of NO measured downstream of the catalyst bed.

In the proposed standards for Stationary Spark Ignition Internal Combustion Engines, EPA states the following with respect to the installation of SCR on natural gas fired engines: “For SI lean burn engines, EPA considered SCR. The technology is effective in reducing NOx emissions as well as other pollutant emissions, if an oxidation catalyst is included. However, the technology has not been widely applied to stationary SI engines and has mostly been used with diesel engines and larger applications thousands of HP in size. This technology requires a significant understanding of its operation and maintenance requirements and is not a simple process to manage. Installation can be complex and requires experienced operators. Costs of SCR are high, and have been rejected by States for this reason. EPA does not believe that SCR is a reasonable option for stationary SI lean burn engines. Consequently, this technology is not readily applicable to unattended oil and gas operation that do not have electricity.[1] However, the technology has been used successfully on lean-burn engines to meet Southern California's stringent limit of 0.15 g/hp-hr. The SCAQMD’s staff report supporting Rule 1110 identifies SCR as a RACT on lean burn engines capably of achieving over 80% NOx control. The staff report also notes that SCR is a relatively high cost control technology option for RICE engines. Reasons given include the “capital cost for the catalyst, the added cost and complexity of using ammonia, and the instrumentation and controls needed to carefully monitor NOx emissions and meter the proper amount of ammonia.” However they also note that the estimated costs have been declining over the past several years and are currently estimated to range from $50 to $125 per horsepower.

Assumptions

There is very little information in the literature regarding the incremental NOx emission reduction of SCR beyond lean burn technology for remote unattended oil and gas operations because there have been very limited installations of this technology for oil and gas compressor engines. Table 9 presents a summary of incremental SCR emission reductions and cost effective control estimates for SCR on a lean burn engine.[2]

Table 9: Incremental SCR Emission Reductions and Cost Effective Control Estimates for SCR

Incremental Cost-Effectiveness Estimates for ICE			Control Techniques and Technologies	
			Incremental	Incremental NO_X
Engine Type	Control Comparison	Horsepower	NO_X Reduction	Cost-Effectiveness
			(tons/year)	($/ton of NO_X Removed)
Lean Burn				
	From Low-Emission Combustion to SCR (96%)	300-500	**3.3**	8,800
		500-1000	**6.6**	10,300

There are several concerns regarding this information. First, it is not known if the emission reductions are based on actual performance tests or theoretical emission calculations. It is also not known what the reference basis is for the emission reduction of 6.6 tons per year of NOx. Review of CARB databases regarding NOx engine emissions does not provide any data regarding actual installations of SCR on lean burn engines for oil and gas operations. There is some very limited performance testing on SCR with lean burn engines that operate on pipeline natural gas (as opposed to field gas) for cogeneration facilities. Such emission data for cogeneration facilities is not applicable to oil and gas compressor engines. This is because cogeneration facilities tend to operate at a continuous load and have personnel present to operate the equipment. The CARB databases also provide testing of oil and gas SCR for high emitting 2 cycle engines (removal rates in the range of approximately 50 to 85 percent). These installations are not comparable to adding SCR to a well controlled engine.

Because of the limited application data for SCR on natural gas fired engines for oil and gas operations it is difficult to estimate the amount of potential emission reduction that could be achieved through the implementation of this technology. In addition, it is not clear how well this technology would perform in unattended remote applications. The limited data that does exist suggests that there may only be a small incremental reduction in NOx emissions beyond lean burn technology and this reduction would result at a very high incremental cost. This technology should be considered an emerging technology and merits additional testing for this unique application.

Because of non-linear chemistry involved in photochemical reactions of ozone and secondary aerosols that result in a reduction of visibility, NOx emission reductions estimated in this analysis may or may not result in equal improvement in ambient air quality levels. Also, excess ammonia slip within the discharge plume of an engine may accelerate the conversion of NOx emissions into particulate nitrate.

Table 10 presents CARB budgetary costs for the installation of SCR on lean burn engines.

Table 10: Cost-Effectiveness Estimates for ICE Control Techniques and Technologies

Selective Catalytic Reduction for Lean Burn				
Horse Power Range	**Capital Cost (S)**	**Installation Cost(S)**	**O&M Cost (S/year)**	**Annualized Cost (S/year)**
301-500	43,000	17,000	35,000	36,000
501-1000	116,000	33,000	78,000	78,000
1001-1500	132,000	53,000	117,000	148,000
Average gt 500 hp	**124,000**	**43,000**	**97,500**	**113,000**

It should be noted that in a white paper prepared by Thomas P. Mark regarding control of Engines in Colorado that he estimates the annual operating cost of SCR on an engine having a capacity of 1000 hp is approximately $140,000 per year and is consistent with the CARB estimate.[3]

Conclusions

The installation of SCR beyond lean burn technology is not a proven or cost effective technology at the present time. With additional development and testing for oil and gas operations, it may become an effective control technology for tertiary control of lean burn engines.

Endnotes

[1] Federal Register Monday, June 12, 2006 40 CFR Parts 69, 63, et al. Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating internal Combustion Engines; Proposed Rule

[2] California Environmental Protection Agency Air Resources Board, 2001, "Determination of Reasonably Available Control Technology.

[3] Thomas P. Mark, October 31, 2003, Control of Compressor Engine Emissions Related Costs and Considerations.

Mitigation Option: NSPS Regulations

Description of Option

EPA is in the process of developing the first national requirements for the control of criteria pollutants from stationary engines. Separate rulemakings are in process for compression-ignition (CI) and spark-ignition (SI) engines. These NSPS will serve as the national requirements, leaving states with the authority to regulate more stringently as might be required in unique situations.

CI NSPS: The final NSPS for stationary CI (diesel) engines was published in the Federal Register on July 11, 2006. It requires that new CI engines built from April 1, 2006, through December 31, 2006, for stationary use meet EPA's nonroad Tier 1 emission requirements. From January 1, 2007, all new CI engines built for stationary use must be certified to the prevailing nonroad standards. (Minor exceptions are beyond the scope of this discussion.)

SI NSPS: The NSPS proposal for stationary SI engines, including those operating on gaseous fuels, was published in the Federal Register on June 12, 2006. Per court order, the rule is to be finalized by December 20, 2007. Like the CI NSPS, certain elements of the SI NSPS will be retroactively effective once finalized. The following summarizes the proposed requirements:

New Source performance Standards (NSPS)

EPA SI NSPS NPRM

[illegible]		2007		[illegible]		[illegible]		[illegible]		2011	
		1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul
All engines	≤ 25 hp			40 CFR 90							
Gasoline & RB LPG	26-499 hp			40 CFR 1048							
	≥ 500 hp		40 CFR 1048								
Natural gas & LB LPG											
Non-emergency	26-499 hp			2.0/4.0/1.0						1.0/2.0/0.7	
	> 500 hp		2.0/4.0/1.0						1.0/2.0/0.7		
Emergency	> 25 hp					2.0/4.0/1.0					
Landfill / digester gas	< 500 hp			3.0/5.0/1.0						2.0/5.0/1.0	
	≥ 500 hp		3.0/5.0/1.0						2.0/5.0/1.0		

[illegible]

Since the proposed NSPS will become an EPA regulation, it will become the base case for emissions for new modified and reconstructed engines. As such, the benefits of this regulation are already incorporated into the Cumulative Effects emission inventories.

Mitigation Option: Optimization/Centralization

Description of Option

Under this option, natural gas fired internal combustion engines that are used to power various oil and gas related operations would be installed with appropriate sized engines (horsepower) for the activity being conducted. The advantage of this approach would be reducing the cumulative amount of horsepower deployed and might result in reducing emissions. This may also be accomplished by using larger central compression in lieu of deploying numerous smaller compressor engines at a number of individual locations such as well sites.

Assumptions

1) Current lease agreements for production cannot be easily changed.
2) Engine emission factors do not change with load.
3) Emission factors on small new, modified and reconstructed engines are consistent with large engines (proposed NSPS will require this).

Method

Short term emissions from compressor engines are based on the amount of fuel used which is a function of capacity (hp) and load. In determining annual emissions, the hours of operation are important. Assuming that emission factors do not change with load, as the load is reduced emissions will decrease. If it is assumed that all engines have the same rate of emissions, simply reducing the number of engines and operating them at higher capacity will likely result in the same amount of fuel usage and the same amount of emissions

Conclusions

Implementation of this option will not result in any quantifiable reduction in emissions.

Mitigation Option: Use of Oxidation Catalyst for Formaldehyde and VOC Control on Lean Burn Engines

Description of Option

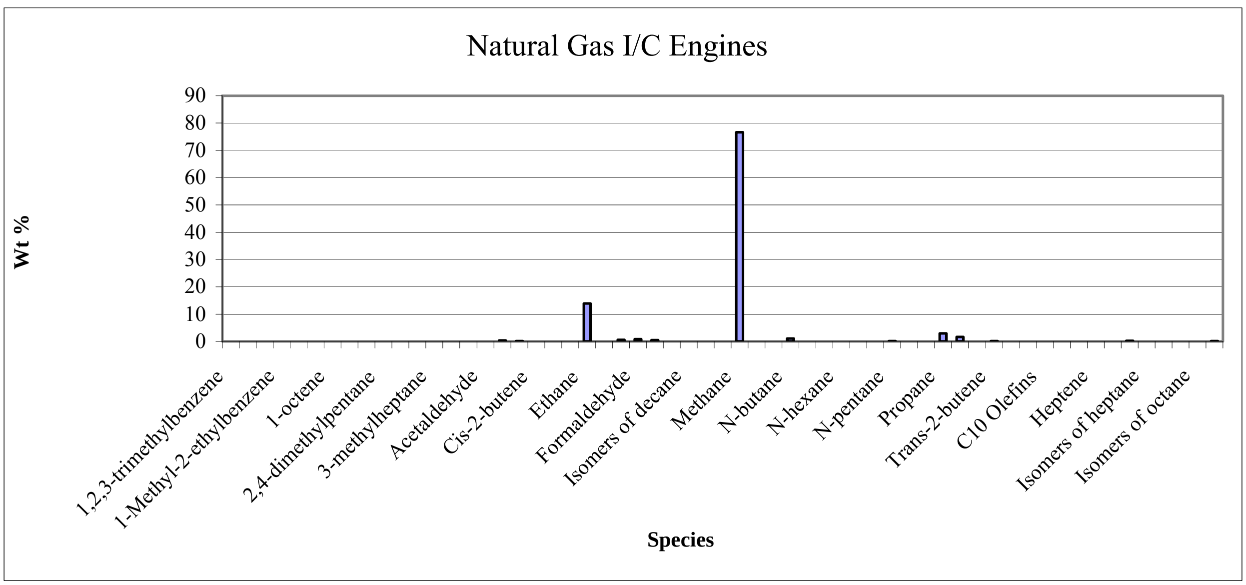
Using this option, existing or new lean burn natural gas fired internal combustion engines would be installed with oxidation catalyst to convert formaldehyde and VOC emissions to CO2. This technology requires the use of an air fuel ratio controller (AFR) in conjunction with the catalyst.

Assumptions

In developing emission inventories for the Four Corners Region, it was assumed that formaldehyde emissions from natural gas fired engines were 0.22 g/hp-hr for all types of engines. There is a large uncertainty in emission factors for formaldehyde which is why a conservative value of 0.22 g/hp-hr was assumed for all engines. In reality, lean burn engines have higher formaldehyde emissions than rich burn engines and therefore it is more appropriate to consider oxidation catalyst technology only for lean burn engines.

The emission inventory for VOC engines used manufacturers' emission factors. There is a large uncertainty if those emission factors represent total hydrocarbons (THC) or VOCs and also they do not include formaldehyde. THC includes methane (C1) and ethane (C2) which EPA does not regulate because they have low photochemical reactivity. The following figure presents the speciation of organics from natural gas fired engines from the EPA Speciate data base and indicates that the majority of the hydrocarbon emissions are methane and ethane. Thus, the projected reductions in hydrocarbon emissions may not affect ozone formation.

Composition of Hydrocarbon Emissions from Natural Gas Fired Engines

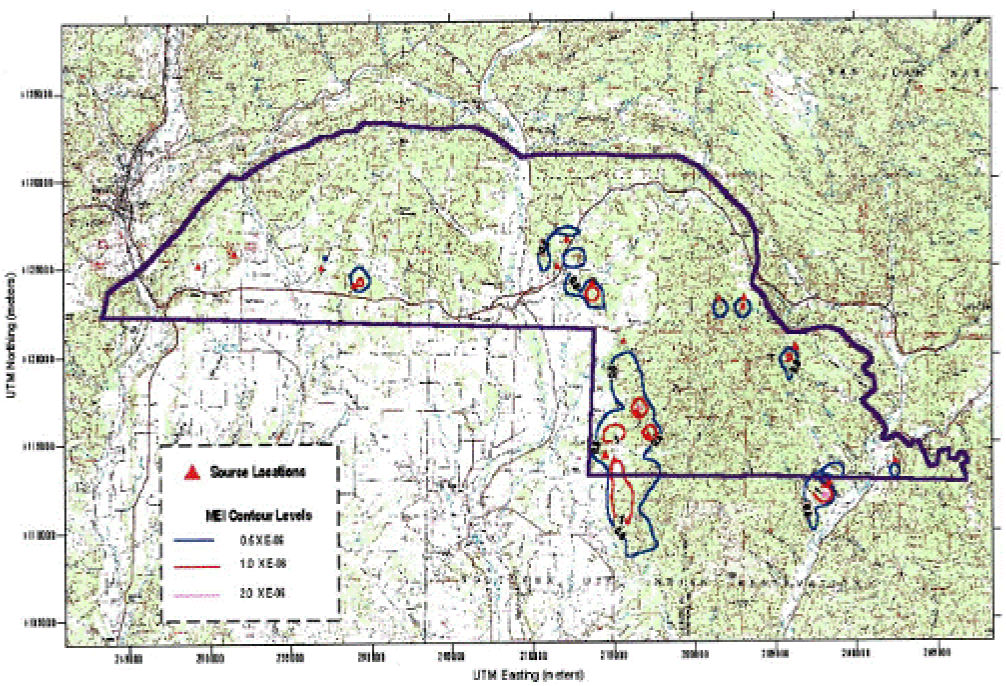


It was assumed that this technology could obtain a 90 percent reduction in hydrocarbons and 80 percent reduction in formaldehyde.

Previous modeling analyses of formaldehyde HAP impacts indicate that maximum impacts for the most likely exposed individual (MLE) are approximately 4x10-6 and have a very localized impact.[1,2] A plot indicating the formaldehyde impacts is presented in the following figure.[3]

Formaldehyde Isopleths from Northern San Juan EIS

Figure 7-5. HAP Incremental Risk Analysis for Formaldehyde MEI (Maximum Development)



Method

Table 11 presents the projected changes in formaldehyde and hydrocarbon emissions if oxidation catalyst were installed on new engines in Colorado and New Mexico.

Table 11: Estimated Changes in VOC and Formaldehyde Emissions with the Installation of Oxidation Catalyst

	VOC Reduction (t/yr)	Unmitigated VOC (t/yr)	Percent VOC Reduction	Formaldehyde Reduction (t/yr)	Unmitigated Formaldehyde (t/yr)	Percent Formaldehyde Reduction
Colorado	204	3115	7	42	471	9
New Mexico	1415	[Frame2] 42,117	3.4	382	365	40

In Colorado, the installation of oxidation catalyst on new engines greater than 300 hp[4] would result in formaldehyde emission reductions of 42 tons per year (a 9 percent reduction in emissions) in 2018. This option would also result in a reduction of 204 tons per year of VOC emissions (a 7 percent reduction in emissions) in 2018. In New Mexico, the installation of oxidation catalyst on new engines greater than 300 hp would result in formaldehyde emission reductions of 385 tons per year (a 40 percent reduction) in 2018. This option would result in a reduction of 1,415 tons per year of hydrocarbon emissions (primarily methane and ethane) and would correspond to a 3.4 percent reduction in total emissions in 2018.

Conclusions
Installing oxidation catalyst on new engines greater than 300 hp in Colorado would result in a reduction of approximately 42 tons per year of formaldehyde over current projected emissions in 2018. and 204 tons per year of VOCs (primarily methane and ethane).

Installing oxidation catalyst on new engines greater than 300 hp in New Mexico would result in a reduction of approximately 382 tons per year of formaldehyde and 1,415 tons per year of hydrocarbons (primarily methane and ethane) for new engines in 2018.

There is a large uncertainty in the VOC estimates because the emitted compounds may be methane and ethane which are not regulated VOCs.
Detailed modeling is necessary to determine the air quality benefit of such reductions with respect to VOCs.

Previous HAP modeling indicates that there are minimal and very localized HAP impacts from natural gas fired engines.

Endnotes
1 Dames and Moore 1999, "Southern Ute Environmental Impact Statement.
2 RTP Environmental, 2004, "Northern San Juan EIS 2002 Air Quality Impact Assessment Technical Support Document Northern San Juan Basin Coalbed Methane Environmental Impact Statement."
3 RTP Environmental, 2004, "Northern San Juan EIS 2002 Air Quality Impact Assessment Technical Support Document Northern San Juan Basin Coalbed Methane Environmental Impact Statement."
4 The lower size cutoff for current lean burn technology.

Mitigation Option: SNCR for Lean Burn Engines

Description of the mitigation option

SNCR stands for Selective Non-Catalytic Reduction. It is similar to Selective Catalytic Reduction (SCR), except that it lacks a catalyst. Like SCR, SNCR can be applied to lean-burn or diesel engines and urea or ammonia is injected into the exhaust manifold. Because it lacks a catalyst, SNCR has a lower conversion efficiency than SCR has.

Do not confuse SNCR with NSCR (Non-Selective Catalytic Reduction), which is applicable to rich-burn engines and uses a catalyst but does not use ammonia or urea as a reductant.

SNCR is used primarily for NOx reduction in boilers. It use in engines has been supplanted by SCR because it has a higher NOx reduction efficiency than SNCR.
SNCR at best can convert only about 60% of the NOx in the exhaust stream compared to about 90% for SCR. Like SCR, SNCR is subject to ammonia slippage.

Because of the low NOx removal rate, the uncertainty in application to natural gas fired engines and because more effective proven technologies exist, this option was not evaluated further.

Mitigation Option: Next Generation Stationary RICE Control Technologies

In evaluating the next generation RICE control technology, it is important to note that current engine technology has resulted in substantial NOx reductions in natural gas fired engines compared to engines that were installed 10 years ago. New large lean burn engines are achieving over 90 percent control reliably and cost effectively. In order for the next generation of controls to be implemented in the field they must achieve the same standards.

In the near term lean-burn technology could be applied to engines smaller than 500 hp. This is a decision to be made by the engine manufacturers with the driving force being emissions regulations. Alternatively, the engine manufacturers or after market control technology companies could partner with researchers at universities and/or national laboratories to test, verify and develop reliable rich burn engine non-selective catalytic reduction (NSCR) system retrofit kits (e.g., air/fuel ratio controllers, lambda sensors, TWC, ion sensors). A next generation NSCR system could include nitrogen injection to achieve higher levels of NOx control (> 95%). The NSCR for rich burn engines may be a very attractive option for the oil and gas industry and for control technology vendors since the technology is well developed and certified for automobile applications.

With that preface this analysis investigates the status of three new and/or evolving emissions-control technologies. They are: laser ignition, air-separation membranes, and lean-burn NOx catalyst (including NOx traps).

Laser ignition is under development in the laboratory, but it has not reached a point where technology transfer viability can be determined.

Air separation membranes have been demonstrated in the laboratory, but have not been commercially available because the membrane manufacturers do not have the production capacity for the heavy-duty trucking industry. Since stationary engines are a smaller market, there is a high probability that the membrane manufacturers could ramp up production in this area.

There are several variations of lean-burn NOx catalysts, but the one of most interest is the NOx trap. NOx traps are being used primarily in European on-road diesel engines, but are expected to become common in the U.S. as low-sulfur fuel becomes available. Applicability to lean-burn natural-gas engines is possible but it will require a fuel reformer to make use of the natural gas as a reductant.

I. Laser Ignition

Description of the Mitigation Option

Laser ignition replaces the conventional spark plugs with a laser beam that is focused to a point in the combustion chamber. There, the focused, coherent light ionizes the fuel-air mixture to initiate combustion. Applicability is primarily to lean burn engines, although laser ignition could be applied to rich burn engines. Air at high pressure is a good electrical insulator that requires high voltage to overcome. This limits the turbocharging pressure and compression ratio because the insulation on spark-plug wires breaks down at high voltage. Laser ignition is not subject to the same limitation, so a lean-burn engine with laser ignition can have a higher turbocharging pressure and a higher compression ratio than one with spark plugs.

Advantages of laser ignition compared to spark plugs include: 1. Longer intervals between shutdowns for maintenance because wear of the electrodes is eliminated, 2. More consistent ignition with less misfiring because higher energy is imparted to the ignition kernel, 3. The ability to operate at leaner air-fuel mixtures because higher energy is imparted to the ignition kernel, 4. The ability to operate at higher turbocharger pressure ratio or compression ratio because the laser is not subject to the insulating effect of high-pressure air, and, 5. Greater freedom of combustion chamber design because the laser can be focused at the geometric center of the combustion chamber, whereas the spark plug generally ignites the mixture near the boundary of the combustion chamber.

However, laser ignition has some unresolved research issues that must be resolved before it can become commercially available. These include: 1. Lasers are intolerant of vibration that is found in the engine's environment. 2. Some means of transmitting the laser light to each combustion chamber should be developed while accommodating relative motion between the engine and the laser. This might be done with mirrors or with fiber optics. Fiber optics generally lead to a simpler solution to the problem. 3. Current fiber optics is limited in the energy flux they can transmit. This leads to a less-than-optimum energy density at the focal point. 4. Wear of the fiber optic due to vibration may limit its lifetime. 5. The cost of a laser is such that multiple lasers per engine are too expensive. Therefore, a means of distributing the light beam with the correct timing to each cylinder must be developed.

Although laser ignition could be applied to rich burn engines, environmental benefits would accrue to lean burn engines. Laser ignition may be able to reduce NOx emissions by as much as 70% compared to spark-ignited engines.[1] However, in the reference cited, the baseline emissions for the engine with spark ignition were higher than the emissions that are currently achievable with lean burn engines. The more consistent ignition compared to spark ignition can be expected to decrease emissions of unburned hydrocarbons. The ability to operate at leaner air-fuel ratios and at higher turbocharging pressure are responsible for the decrease of NOx emissions because of lower combustion temperatures. Laser ignition systems have not been developed to the point where the effect of improved combustion chamber design can be measured. It is reasonable to expect that a better combustion chamber design would further decrease emissions of unburned hydrocarbons, carbon monoxide, and NOx. In actual operation of the engine, misfiring of one or more cylinders contributes to loss in efficiency and increase in emissions. With the laser ignition system, misfiring can be significantly reduced. Whether laser ignition combined with lean-burn engine technology can meet the Southern California NOx limit of 0.15 g/hp-hr will be the subject of further research.

One of the advantages of laser ignition is its potential to eliminate downtime due to the need to change spark plugs. This advantage would accrue to both rich burn engines and lean burn engines. Higher efficiency due to near elimination of cylinder misfirings is an additional benefit.

Laser ignition would compete with selective catalytic reduction (SCR) applied to lean-burn engines. Although costs are unknown at this time, laser ignition is likely to be the lower cost alternative.

A tradeoff for engine manufacturers, assuming that laser ignition can be developed to the point of commercial feasibility, is whether or not to develop retrofit kits. Retrofits would be expected to take away sales of new engines.

A tradeoff for engine users is whether to continue using spark ignition or to purchase a laser ignition that is initially more expensive but has a future economic benefit.

Another tradeoff for engine users is whether to retrofit laser ignition to an existing engine or to spend more money for a new engine in return for future benefits.

Assumptions

In the analysis, it is assumed that the limitations of laser ignition described above can be overcome through research and development. It is further assumed that NOx emissions can be reduced by 70% compared to spark-ignition lean-burn engines. Until more research is done, the 70% reduction is most likely an upper limit. This reduction is due to the ability to operate at higher turbocharging pressure, hence leaner air/fuel ratios and lower combustion temperature than is currently possible with spark-ignition engines. Since lean-burn engines are primarily those over 500 hp, the technology is assumed to apply only to engines larger than 500 hp. The technology is assumed to be retrofitable to any engine that uses 18-mm spark plugs, so it is applied to all engines, new and existing, in the Colorado and New Mexico databases.

Conclusions

Testing in the laboratory has shown potential emissions reductions in the 30% to 60% range, which may or may not be achievable when this technology is implemented in the field.

II. Air-Separation Membranes

Description of the Mitigation Option

The purpose of air-separation membranes is to change the proportion of nitrogen to oxygen in air. A membrane can be optimized to either enrich the oxygen content or to enrich the nitrogen content. Both the oxygen enrichment mode and the nitrogen enrichment mode have been tested in the laboratory with diesel engines. The nitrogen enrichment mode has been tested in the laboratory with Natural Gas Fuel as well. The oxygen enrichment mode and the nitrogen enrichment mode are mutually exclusive.

Oxygen enrichment produces a dramatic reduction in particulate emissions in diesel engines at the expense of increased NOx emissions. However, Poola[2] has shown that the effects are non linear such that a small enrichment (1 percentage point or less) produces a significant reduction in particulate emissions with only a small increase in NOx emissions. By retarding the injection timing, one can achieve a reduction in both NOx and particulate emissions. The overall benefits of oxygen enrichment are relatively small and have not been tested with natural gas-fueled engines, so it will not be considered further.

Nitrogen enrichment produces the same effect on emissions as exhaust-gas recirculation; NOx decreases. It can be applies to either diesel or rich-burn natural-gas engines. Unlike exhaust-gas recirculation (EGR), nitrogen-enriched air contains only the components of pure air. Manufacturers of both diesel and natural-gas engines are concerned that components of exhaust gas could shorten the life of the engines with EGR. In the case of diesel engines, it is clear that exhaust particulate matter could cause wear between the piston rings and cylinder liners. Even in the case of rich-burn engines, the exhaust gas contains condensed liquids that may cause wear. As recently as August, 2004, the Engine Manufacturers Association does not consider EGA to be a viable option for rich-burn engines.[3] Thus, nitrogen enriched air is seen as an alternative to EGR because it contains no components that are not found in air. Published data from tests in natural-gas engines show engine-out NOx reductions of 70% are possible with nitrogen-enriched combustion air. [4] When combined with non-selective catalytic reduction (NSCR), the overall NOx reduction can reliably exceed 90%.

The cost of nitrogen-enriched air systems are expected to be higher than that of EGR. However, nitrogen-enriched air does not have components that can cause increased engine wear as EGR does.

Assumptions

Only nitrogen-enriched air is considered in this analysis. The technology is assumed to be retrofittable to all rich-burn engines, new and existing. While nitrogen-enriched air can be combined with non-selective catalytic reduction (NSCR), only the effects of nitrogen-enriched air are considered here. The effect is assumed to be the same as that of EGR; it can produce a 70% reduction in NOx emissions. This is most likely an upper limit.

Conclusions

Testing in the laboratory has shown potential emissions reductions in the 50% to 90% range, which may or may not be achievable when this technology is implemented in the field. The upper end assumes integration as a component of a reasonably well-designed (use of current state of the art air fuel ratio controllers / sensor technologies) NSCR system.

III. Lean-Burn NOx Catalyst, Including NOx Trap

Description of the Mitigation Option

Lean-burn NOx catalysts have been under development for at least two decades in the laboratory with the intent of producing a lower cost alternative to SCR. They do not have the ammonia slip problem associated with SCR, but they typically use some of the fuel as a reductant.

Several variants of lean-burn NOx catalysts have been studied: (1) Passive lean-burn NOx catalysts simply pass the exhaust over a catalyst. The difficulty has been low NOx conversion efficiency because the oxygen content of a lean-burn exhaust works against chemical reduction of NOx. Conversion efficiencies of the order of 10% are typical.[5]

(2) Active lean-burn NOx catalysts use a fuel as a reductant. The catalyst decomposes the fuel, and the resulting fuel fragments either react with the NOx or oxidize. Methane is much more difficult to decompose than heavier fuels, such as diesel [aardahl.pdf. A wide range of NOx reduction efficiencies from 40% to more than 80% have been published. [6,7] Variants of active lean-burn catalyst systems may use plasma or a fuel reformer to produce a more effective reductant than neat fuel.[8,9,10]

(3) NOx trap catalysts are a more recent development that has seen some laboratory success. Operation is a two-step cyclic process. In the first stage the NOx trap adsorbs NOx while the engine operates in a lean-burn mode. In the second stage, the engine operates with excess fuel in the exhaust. The fuel decomposes on the catalyst and reduces the NOx to molecular nitrogen and water. With natural gas as the fuel, a fuel reformer is necessary to break up the extremely stable methane molecule for use as a reductant When the supply of trapped NOx is exhausted, the system reverts back to first-stage operation. NOx reduction efficiencies in excess of 90% have been published.[11] A sophisticated engine control is required to make this system work.

NOx traps have been proven to be effective and have seen some limited commercial success in Europe. NOx traps are one of the reasons for the dramatic reduction in sulfur content of diesel fuel in the U.S. Fuel-borne sulfur causes permanent poisoning of NOx-trap catalysts. There are doubts regarding the NOx conversion efficiency levels after 1,000 hours or longer use. This should be evaluated, as well as the durability of the equipment.

Active lean-NOx catalysts have seen limited commercial success because they are less effective than NOx traps and are not being considered for on-road diesel engines. Some instances of formation of nitrous oxide (N2O) rather than complete reduction of NOx have been reported.

Passive Lean-NOx catalysts do not provide enough NOx reduction to be considered viable.

Costs of retrofitting a lean-burn NOx catalyst are estimated at $6,500 to $10,000 per engine [retropotentialtech.htm.][11] $15,000-$20,000 including a diesel particulate filter [V2-S4_Final_11-18-05.pdf] for off-road trucks.[12] Estimates are $10-$20/BHP for stationary engines [icengine.pdf]. [14]

Little information on the cost of NOx-trap catalytic systems was found. The overall complexity of a NOx-trap system is only slightly more than that of a lean-burn NOx catalyst, so costs can be expected to be slightly higher. With methane-burning engines, both active lean-burn NOx catalysts and NOx-trap catalysts require a fuel reformer or other means of dissociating methane. This will add an increment of cost.

Both active lean-NOx technology and NOx-trap technology impose a fuel penalty of 3-7%.

Assumptions

Only NOx-trap catalysts, which can remove up to 90% of the NOx in the exhaust stream are considered for this analysis. The technology is applicable to lean-burn engines, which are considered to be those having more than 500 hp in the Colorado and New Mexico databases. The technology is assumed to be retrofitable, so it is applied to all new and existing engines greater than 500 hp.

Conclusions

Testing in the laboratory has shown potential emissions reductions in the 40% to 70% range, which may or may not be achievable when this technology is implemented in the field.

Summary

Three technologies are reported: laser ignition, air-separation membranes, and lean-burn NOx catalyst.

Laser ignition is not presently a commercial product. The impetus for investigating it is the potential to eliminate the need for changing spark plugs. It will also allow operation at leaner air-fuel ratios, higher compression ratios, and higher turbocharging pressure. Leaner air-fuel ratios imply lower engine-out NOx emissions so the after treatment can be smaller or can give lower overall emissions. Higher compression ratios and turbocharging ratios imply higher engine efficiency.

Air-separation membranes used to deplete oxygen from the combustion air can serve as a clean replacement for EGR. That is, an engine using oxygen-depleted air would not be ingesting combustion products. Engine manufacturers are concerned that EGR will shorten the life of their engines and lead to premature overhauls and warranty repairs. The technology has been demonstrated in the laboratory, but has not been used for heavy-duty trucks because membrane manufacturers do not have enough production capacity for the market. Stationary engines are a smaller market, so the membrane manufacturers may be able to ramp up their capacity with stationary engines. Applicability is to diesel engines and rich-burn natural-gas engines. Oxygen-depletion membranes are not applicable to lean-burn natural-gas engines.

Lean-burn NOx catalysts have several forms, but the one that is of most interest is the NOx-trap catalyst. Unlike SCR, lean-burn NOx catalysts use the engine's fuel as a reductant and do not require a separate supply of reductant. It is a well proven in the laboratory and is commercially available in Europe for diesel engines, but it requires a fuel reformer if natural gas is used as the reductant. A sophisticated control system is required to cycle the engine between its two modes of operation. Ammonia slippage is not an issue with NOx traps, and if there is any slippage of unburned fuel it can be removed with an oxidation catalyst. Cost is high but less than that of SCR systems. A large part of the cost of SCR is the ammonia or urea reductant necessary to make it work. A disadvantage of NOx traps is that they are intolerant of fuel-borne sulfur. For diesel fuel, the sulfur content must be less than 15 ppm. Fuel-borne sulfur permanently poisons the catalyst. Since fuel is used as a reductant, there is a fuel consumption penalty of 3-7%.

Endnotes

[1] B. Bihari, S.B. Gupta, R.R. Seka4r, J. Gingrich, and J. Smith, “Development of Advanced Laser ignition System for Stationary Natural Gas Reciprocating Engines,” ICEF2005-1325, *ASME-ICE 2005 Fall Technical Conference*, Ottawa, Canada, 2005

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[12] "Summary of Potential Retrofit Technologies, Technical Summary," U.S. Environmental Protection Agency, March, 2006.

[13] "WRAP Off-raod Diesel Retrofit Guidance Document, Volume 2, Section 4," November, 2005.

[14] Manufacturers of Emissions Controls Association, op cit.

Mitigation Option: Automation of Wells to Reduce Truck Traffic

Assumptions
About 50% of traffic on dirt roads in the Four Corners region is oil and gas related.

Substantially less than widespread implementation is likely, assume 25%.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor applied that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

Automation would not quite "zero out" vehicle-related emissions for those wells that are automated because of non-routine maintenance, perhaps it would be reduced by 80%.

Vehicle miles traveled is proportional to dust generated.

Method
Applying the percent reduction, 80% reduced by 50% to account for extent of oil and gas traffic and further reduced by 75% to account for effectiveness. So, the over all reduction would be 10%.

Conclusions
For road dust, the total PM10 emissions in the region are 1959 tpy (tons per year), while the total of PM2.5 is 196 tpy based on WRAP inventory information. Hence, the estimated reduction in road dust emissions because of automation would by 196 tpy of PM10 and 20 of PM2.5.

For tailpipe emissions, the total NOx emissions in the region are 916 tpy, which means the reduction because of automation would be 92 tpy.

Mitigation Option: Reduced Truck Traffic by Centralizing Produced Water Storage Facilities

Assumptions

About 50% of traffic on dirt roads in the Four Corners region is oil and gas related.

Substantially less than widespread implementation is likely because it is voluntary, assume 20% participation which is a bit higher than is usually assumed for regulatory programs.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor applied that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

Hauling of produced water constitutes about 20% of total O&G traffic.

Streamlining hauling might reduce such traffic by about 50%.

The relative mix of heavy duty compared to light duty vehicles is unknown, so estimating emissions reductions for this option might be a bit conservative since it is based on an overall average that includes both light- and heavy-duty and the approach is intended just for heavy-duty which produce more dust on a per unit basis.

Method

Based on the above assumptions of 50% of total traffic is oil and gas related, of which 20% are hauling produced water and of which 20% will likely undertake the program. Therefore, of the total unpaved road traffic generating road dust, 2% would be reducing emissions under this approach. One would then apply the 50% control efficiency.

Conclusions

For road dust, the total PM10 emissions in the region are 1959 tpy (tons per year), while the total of PM2.5 is 196 tpy based on WRAP inventory information. Hence, the estimated reduction in road dust emissions because of automation would by 39 tpy of PM10 and 4 tpy of PM2.5.

Mitigation Option: Reduced Truck Traffic by Efficiently Routing Produced Water Disposal Trucks

Assumptions

About 50% of traffic on dirt roads in the Four Corners region is oil and gas related.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor applied that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

Hauling of produced water constitutes about 20% of total O&G traffic.

Streamlining hauling might reduce such traffic by about 50%.

Miles traveled is proportional to dust generated.

The relative mix of heavy duty compared to light duty vehicles is unknown, so estimating emissions reductions for this option might be a bit conservative since it is based on an overall average that includes both light- and heavy-duty and the approach is intended just for heavy-duty which produce more dust on a per unit basis.

Method

Based on the above assumptions of 50% of total traffic is oil and gas related, of which 20% are hauling produced water. Therefore, of the total unpaved road traffic generating road dust, 2% would be reducing emissions under this approach. One would then apply the 50% control efficiency.

Conclusions

For road dust, the total PM10 emissions in the region are 1959 tpy (tons per year), while the total of PM2.5 is 196 tpy based on WRAP inventory information. Hence, the estimated reduction in road dust emissions because of automation would by 196 tpy of PM10 and 20 tpy of PM2.5.

Mitigation Option: Reduced Vehicular Dust Production by Covering Lease Roads with Rock or Gravel

Assumptions

About 25% of traffic on dirt roads in the Four Corners region is on oil field lease roads.

Once applied, the improved surface would be maintained regularly by grading and reapplying gravel or rock.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have had an EPA-recommended factor that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

The level of emissions reductions achieved by the application of gravel to roadways can vary from place to place.

Considering uncertainties in road dust emissions estimates, the more conservative end of a range will be used.

Method

The total annual road dust emissions of PM10 in the Four Corners region are 1959 tpy (tons per year), and 196 tpy of PM2.5 based on the inventory information from the WRAP.

Based on a comprehensive EPA study (Raile, 1996) conducted in the Kansas City, Missouri area, emissions of PM10 were reduced by 42% to 52% by the application of gravel.

Conclusions

Therefore, emissions of PM10 on lease roads would be reduced by about 206 tpy, and by about 21 tpy of PM2.5. This is based on the following:

reduction of particulate from lease roads =
total road dust emissions times 25% times 42%.

References

Raile, M.M. 1996. Characterization of Mud/Dirt Carryout onto Paved Roads from Construction and Demolition Activities. U.S. EPA. EPA/600/SR-95/171.

Mitigation Option: Reduced Vehicular Dust Production by Enforcing Speed Limits

Assumptions

The average posted speed is 30 mph.

About half of the vehicles on dirt road exceed the posted limit by more than 5 mph. The average for these drivers is 40 mph or 10 mph over.

Therefore, the reduction in speed for those exceeding posted limits would be about 10 mph if enforcement was undertaken and was 100% effective. Such enforcement is not 100% effective.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor that estimates the transportable fraction, i.e. how much would move beyond the immediate vicinity.

The effectiveness of enforcement initiatives is dependent on resources allocated.

Method

The equation for estimating road dust PM10 emissions from EPA's AP-42 is:

((1.8*(silt content/12)^.1) * (veh. Speed/30)^.5) - .00036) /
(surface moisture/.5)^.2

Therefore, adjusting the vehicle speed would change the multiplier in the numerator from 1.15 (i.e. (40/30)^.5) to 1.0 (i.e. (30/30)^.5).

So, assuming even 50% effectiveness in mitigating speeding, and generally the assumption is lower, the reduction from enforcing a 30 mph speed limit on dirt roads in the entire Four Corners region would be about 7.5%.

Conclusions

Remembering that half of the traffic on dirt roads are exceeding the speed limit by more than the threshold 5%, applied to the total road dust emissions of PM10 of 1959 tpy, the reduction would be approximately 73 tpy. The reduction in PM2.5 from a total of 196 tpy would be 7 tpy.

Mitigation Option: Emissions Monitoring for Proposed Desert Rock Energy Facility to be Used Over Time to Assess and Mitigate Deterioration to Air Quality in Four Corners Region

Assumptions

Generally, much post-construction ambient monitoring for permitted facilities by the source is conducted on-site. Air quality permits generally contain conditions to require continuous emissions monitoring from the stacks for criteria pollutants. New federal mercury rules will require continuous emissions monitoring for mercury for Desert Rock Energy Facility beginning in 2010.

Given the tall stack heights of the proposed facility, the greatest air pollution impacts from emissions from the facility will be quite some distance from the facility.

Review of Proposed Approach

Continuous PM2.5 monitoring of primary fine particulate by the facility on-site would not likely provide useful information where the effect of emissions would be well downwind, plus direct fine particulate emissions by more modern power plants are usually not substantial. However, monitoring fine particulates and its chemical components (including ammonia) at off-site locations where models indicate significant impacts from the facility would be useful. Also, since much fine particulate is formed in the atmosphere rather than emitted directly, measurements of sulfur dioxide and oxides of nitrogen offsite would also be useful.

Stack mercury measurements might be useful from a research perspective in performing source apportionment work in the Four Corners region.

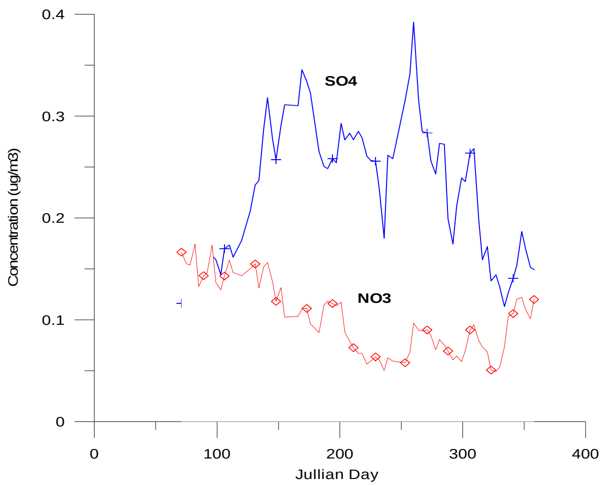
As is discussed above, on-site ambient monitoring of volatile organic compounds (VOC) may not be an effective means of understanding the ambient impact of these emissions, but off-site monitoring of ozone precursors like VOC and nitrogen oxides at predicted maximum impact locations would be useful.

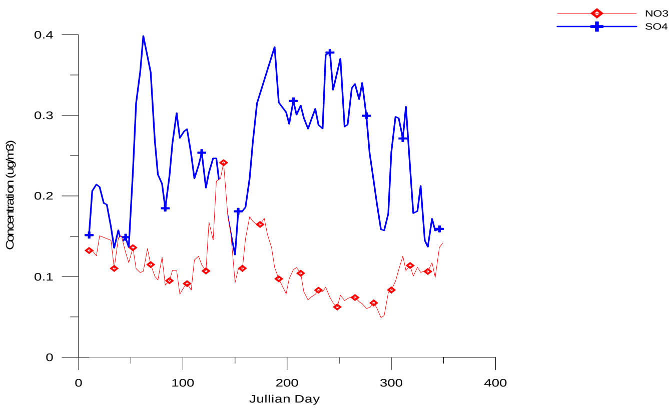
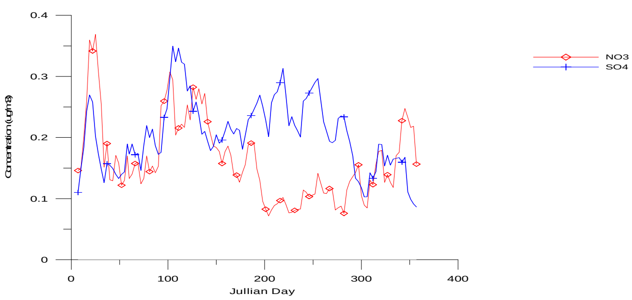
CUMULATIVE EFFECTS: PUBLIC COMMENTS

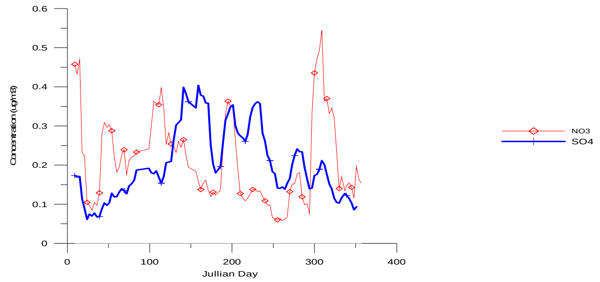
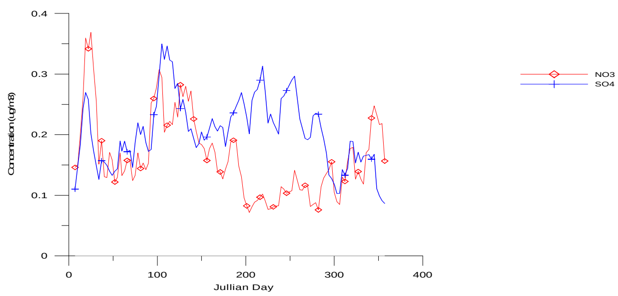
Cumulative Effects Public Comments

Comment	Mitigation Option
I have been concerned for many years about the air quality of the Four Corner's region because of the coal fired power plants in N.M. I attended two of the Four Corner's air quality forums in the past and was disturbed by their reports. As a nurse, I am especially concerned for the health of the Native Americans and other people who reside close to the power plants because of their incidence of lung disease. As a resident of La Plata canyon for 20+ years with a high mercury level, I am concerned about my own health and notice more air pollution, lack of visibility, every time I hike in the mountains. I believe for everyone's health, alternative sources of energy; e.g. solar, wind energy is a much better solution and would still serve as a revenue source to the Navajo nation. Desert Rock should not be built and the others should be phased out as planned many years ago or at least upgraded to standards that were set by the Clinton administration.	General Comment
We do NOT need another power plant in the 4 Corners. I notice the dirty air in this area all of the time and especially on weekends. Drive up from Albuquerque and see the air get dirtier. Also, go out from the 4 Corners and notice the beautiful blue skies as you progressively leave the area. I teach school and stress to my students they need to take care of the this planet earth because there is no spare earth. I would like to stress to everyone else that this needs to be done. Solar, wind and other energy sources should be used.	General Comment
It breaks my heart to think that another coal fired plant may be added to our "pristine" 4 corners area. Even in Pagosa Springs we have some hazy smog some days, and when driving south and west of Farmington, that horrible yellow-brown cloud can be seen for miles! I was shocked to see that poisonous cloud in Monument valley, and northwest Utah. It's all pervasive now so I can't imagine what it will be like with more coal -spewing plants. We must use non polluting energy sources for the health of all of us!	General Comment
The Task Force report presents data on the potential emission reductions for the Four Corners Power Plant and the San Juan Power Plant. The Cumulative Effects Work Group needs to evaluate potential power plant mitigation options that are presented in the report and develop a quantitative summary of all potential mitigations options which have technical merit. It is useful to place the emission reductions suggested for power plants in perspective to those developed for oil and gas sources. As stated in the Draft Report, for the Four Corners Power Plant the installation of presumptive BART could result in SO2 emission reductions from a minimum of 12,455 tons per year to a maximum of 19,927 tons per year. Similarly, NOx emission reductions could range from 13,651 tons per year to 57,118 tons per year. Since SO2 and NOx emissions are considered as having similar visibility impairment potential, the magnitude of the total emission reductions possibly affecting visibility could range from 26,106 to 77,045 tons per year. For the San Juan Power Plant using data presented in the Task Force Report, estimated SO2 emission reductions could be approximately 9,000 tons per year and NOx reductions could be approximately 11,000 tons per year. For this plant the combination of SO2 and NOx possible reductions of 20,000 tons per year might be achieved. The information contained in the Draft Report regarding possible emission reductions for this source is not as complete as for the Four	General Comment

Comment	Mitigation Option
Corners Plant and additional data should be developed and presented. If the suggested emission reduction strategies were implemented at both plants, total SO2 and NOx emission reductions of visibility impairment pollutants could range from 46,106 tons per year to 97,046 tons per year. In addition, review of the emission data in the Draft Report indicates that at the Four Corners Power Plant NOx emissions are greater than SO2 emissions (Figure 2 FCPP Emission Trends). However, in 2003 SO2 emissions were further reduced so that the ratio of NOx to SO2 emissions increased. At the San Juan Power Plant prior to 1990, SO2 emissions were greater than NOx emissions while in 1999 SO2 and NOx emissions were equal (Figure 1 San Juan SO2 and NOx). After that time, SO2 emissions were less than NOx emissions. The trends in emissions at these facilities may be important in understanding the trends in the IMPROVE monitoring data. Engineering and economic feasibility studies need to evaluate the ability of the facilities to continuously achieve emission reductions in a cost effective manner. The potential emission reduction that could be realized with the installation of additional controls on power plants need to compared with the emission reductions reported by the Draft Task Force Report for oil and gas sources. The installation of NSCR on existing small engines in Colorado and New Mexico could result in emission reductions of approximately 10,244 tons per year. These emission reductions are only a small fraction of the reductions possible from power plants (minimum ratio of power plant reduction to oil and gas reductions 4.5 – maximum ratio of power plant reduction to oil and gas reductions 9.5).	
The Draft Task Force Report presents recommendations for mitigating emissions from drilling rig diesel engines. At the present time there is insufficient information regarding the level of emissions from these sources in the region. The Cumulative Effects Group should develop emission data regarding the magnitude of emissions in both Colorado and New Mexico and then develop estimates of potential emission reductions that could be achieved. The emission calculations should be based on site specific information that represents the length of time to drill a new well, engine loads and engine capacity. One important fact that needs to be considered is that the drilling rig engines are typically replaced at a frequency of every 5 years (replaced not rebuilt). This rate of turnover is very important because the engines are replaced with the required current control technology. This should be the baseline against which alternative mitigation options should be considered. It is recommended that the Cumulative Effects Group continue to analyze and evaluate emission reduction options for this source group.	General Comment
The following plots present selected years of rolling 5 data point averages of the SO4 and NO3 concentrations compared to Julian day for the IMPROVE data from Mesa Verde. Using a rolling 5 data point average provides some smoothing of the data but allows correlations between SO4 and NO3 to be observed. The plots for 1988 and 1990 indicate a large fraction of coincident peaks of SO4 and NO3. This is an important finding because it suggests that these events may result from coal fired sources because natural gas fired sources or mobile sources do not emit significant SO2. In addition, NO3 concentrations are smaller than SO4 concentrations. The data from 2002, 2003 and 2004 indicate that a change has occurred in the relationship of SO4 and NO3 measurements and that there is a very strong correlation of SO4 and NO3	General Comment

Comment	Mitigation Option
events, again suggesting a coal fired source. However, in 2002, 2003 and 2004 NO3 concentrations are equal to or greater than SO4 concentrations. As mentioned in the power plant emission section, SO2 reductions began in 1999 and after that time NOx emissions were greater than SO2 emissions. This trend in changes in emissions is very consistent with the monitoring data and again suggests visibility impacts are likely from coal fired sources. This is a preliminary hypothesis that needs more evaluation and may explain why NO3 levels have been increasing at Mesa Verde. If this finding is confirmed, it has important ramifications regarding improvement in air quality. This is the type of focused analyses that needs to be conducted before mitigation options are selected and implemented.  **1988 SO4 and NO3 Concentrations 5 Day Running Average** **Mesa Verde**	

Comment	Mitigation Option
 1990 SO4 and NO3 concentrations 5 day running average  **2002 SO4 and NO3 Concentrations 5 Day Running Average Mesa Verde**	

Comment	Mitigation Option
 **2003 SO4 and NO3 Concentrations 5 Day Running Average** **Mesa Verde**  **2004 SO4 and NO3 Concentrations 5 Day Running Average** **Mesa Verde**	
last paragraph before Suggestions for Future Work...should the reference be to Table 2 rather than Table 1?	Overview of Work Performed

Comment	Mitigation Option
Table 1 - Selective Catalytic Reduction (SCR) on Drilling Rig Engines: It is stated "that some data exists on drilling emissions. The State of Wyoming evaluated this technology based on a pilot study in the Jonah Field & concluded that is not a cost effective technology, but further analysis is needed." This paragraph references the cost analysis WY did for SCR on diesel rig engines, but does not provide or reference any information on what conditions and assumptions WY used in conducting this analysis. If possible the CE workgroup should obtain and review the WY analysis on SCR, in addition to other diesel control options WY analyzed. Table 1 - Follow EPA New Source Performance Standards (NSPS) for RICE: EPA suggests revising the Summary of Result first sentence "This proposed emission standard will become the baseline for new, **modified, and reconstructed** engines. Table 1 - Install Non Selective Catalytic Reduction (NSCR) on Rich Burn Engines for RICE. It is unclear in the Summary of Result what EPA performance standard is being referenced, and how the 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE have been considered by the CE workgroup. The NSPS for spark ignition engines will apply to **new, modified, and reconstructed** units starting in January 2008. The 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE notes that BLM/USFS, at the request of CO and NM, is currently requiring NSPS comparable emission limits on as a Condition of Approval for their Applications for Permits to Drill. The States' request was that BLM/USFS immediately establish in every Application for Permit to Drill (APD) a nitrogen oxide (NOx) limit of 2.0 grams per horsepower hour for all **new and replacement** engines less than 300 hp (excluding engines with horsepower less than 40). In addition, New Mexico and Colorado have requested that for all new and replacement engines greater than 300 hp, the BLM and the USFS establish in every APD a NOx limit of 1.0 gram per horsepower hour. EPA Region 8 formally supports both these requests from Colorado and New Mexico. It should also be noted that the Mitigation Option: Interim Emissions Recommendations for Stationary RICE section in the Draft Mitigation Options Report states that "BLM in New Mexico and Colorado are currently requiring these emission limits as a Condition of Approval for their Applications for Permits to Drill. These limits currently apply only to **new and relocated** engines ... (compressors assigned to the well APD)..." In developing assumptions for potential NOx reductions from this requirement in APDs, how did the CE workgroup determine, or assume, what percentage of the existing engines (compressors) in the 4 Corners area would be required to meet this requirement?	Overview of Work Performed

Comment	Mitigation Option
1. Given electric compression would shift emissions generated from NG compressor engines through use of electric engines to emissions from power generation (i.e., "the grid"), this option is clearly "cross-cutting." We recommend that the coordination with the Power Plant WG in the analysis of this option. 2. We were unable to reproduce the emission reduction numbers from the data provided in the analysis (tons/yr deltas provided in Table 4). Based on the data provided we calculate a total of 631 tons/yr reductions in NOx and SO2 based the 25 worst engines and the average power plant emissions in Table 3. 3. In course of installing electric compression to replace the natural gas fired compression engines, the analysis correctly assumes that the emission of pollutants will shift from the replaced compressor engines to increased electric load demand from the grid. In course of review of the Natural Resources Defense Council (NRDC) "Emission Data for the 100 Largest Power Producers", it appears that baseline average emission factors used for emission difference calculation are the national average emission factors for the identified owner utility companies (average of all plants, regardless of location or on which power grid). The electric power for electric compression will come from the Western Grid which draws power from generating stations in the western United States. Among the three electric power producers, Xcel is the largest producer with 81,283,493 MWhs capacity compare to 21,230,675 MWhs for both PNM and Tri-state. The baseline average emission factors based on national average emission factors of these three electric power producers have potential to distort the emission difference calculation because Xcel's power generation facilities in Minnesota, South Dakota, Texas, and Wisconsin are not supplying electricity to the Western Grid. A brief description of grid system is provided later in this document. A better measure of the effectiveness of this option would be the use of average NOx and SO2 emissions from Four Corners Generating Station and San Juan Generating Station. In case example case provided in the analysis, replacing 25 worst engines with total 2,701 hp in NM side with electric compression, will result in net NOx + SO2 reduction of 610 tons/year. A net NOx +SO2 reduction of approximately 20,000 tons/year can be achieved by replacing all rich burn engines (approximately 1,500 in NM inventory) emitting greater than 5 g/hp-hr. Although it may not be practical or economically feasible to replace all rich burn compressor engines with electric motors, further analysis of the locations/ configurations of existing compressor stations may reveal that conversion to electric is practical and makes sense. Factors like proximity to the electric grid, ROW, number of engines, are factors that would need to be evaluated. 4. The electricity for the electric compression in the San Juan area will be drawn from Western Interconnect or Grid. We recommend that a good approximation for baseline emission factors will be the averages of emission factors for the power plants supplying electricity to the Western Grid. The following steps can be taken to obtain the baseline average emission factors for the emission difference calculation: a. The average emission factors for fossil fuel powered power plants supplying electric power to the Western Grid can be calculated using the emission data	Install Electric Compression

Comment	Mitigation Option
from the EPA's CAMD inventory. The EPA's Clean Air Market Data (CAMD) (http://camddataandmaps.epa.gov/gdm/index.cfm) provides NOx, SO2, and CO2 emission as well as heat input for the Title IV power generating units. b. The net power generation by state by type of producer by energy source is available at the Energy Information Administration (EIA) website (http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html). c. A fraction between calculated average baseline emission factors for the Western Grid based on EPA data and the total power generation for the Western Grid obtained from EIA's website will used to obtain the average baseline emission factors for emission difference calculations. 5. The worst case NOx emissions from coal-fired plants is 4.5 lbs/MWh, which is equivalent to 1.5 g/hp-hr. The coal-fired plants produce a lot more NOx emissions than the gas field sources do: 160,264 tons/year compared to 38,632 tons/year. A 5% reduction of NOx emissions from the coal-fired plants is the same as a 21% reduction in NOx from gas field sources. 6. We recommend that the Task Force evaluate on-site lean-burn electric generators as an alternative power source for electric compression.	
The SUGF recommends further research and testing of this mitigation option to help determine the amount of emissions reduction that can be accomplished on a continual, reliable basis. If technology could be developed and maintained on a regular basis, this option could prove to be valuable in retrofitting existing rich burn units.	Use of NSCR for NOx Control on Rich Burn Engines
In the section Mitigation Option: Use of NSCR for NOx Control on Rich Burn Engines it is stated in the Assumptions (p. 13): "Currently, recent EIS RODs in Colorado and New Mexico require performance standards for new engines that will accelerate the implementation of the 2008 and 2010 federal NSPS for non road engines." The term "replacement" is not used, only "new" engines. What is the CE workgroups understanding related to what type of engines would fall under the replacement category, and was this type of engine considered in the assumptions as being retrofitted to meet the interim recommendation of 2 g/hp/hr? Engine Size < 100 hp Case 1 (p. 14): It is stated that "it was assumed that NSCR for this situation would reduce NOx emissions by 50 percent in Colorado and New Mexico and would result in a NOx emission factor of 6.7 g/hp-hr in Colorado and 8.0 g/hp-hr in New Mexico." What is the basis for this assumption? The 2 g/hp-hr interim recommendation for new and replacement engines 300 hp and less (excluding engines less than 40 hp) has been in place since '05, which is almost 3 years ahead of the NSPS implementation date. Does the CE Workgroup have any information on how much impact this interim recommendation, as implemented through BLM/USFS APDs, has had on the average NOx emission factor from the current engine fleet in the 4 Corners area. Tables 6 and 7: Can some narrative be added that explains how emissions reductions are calculated and what each column in the tables represents? Why is table 6 (CO) different from table 7 (NM)? It is unclear how some of the emission reduction values have been calculated in tables 6 and 7. For example, in table 6 why is the emission reduction for < 100 Hp engines 130 TPY instead 143 TPY (50% x 286 TPY)?	Use of NSCR for NOx Control on Rich Burn Engines

Comment	Mitigation Option
1. Test data on small two-stroke NSCR retrofitted engines (Ajax DP-115) show NSCR can achieve large NOx emission reductions between 79% and 93% (Chapman, 2004a). On four stroke engines Chapman (2004b) indicates that "these catalyst systems reduce NOX emissions by over 98 percent, while reducing VOC by 80 percent and carbon monoxide by over 97 percent. NOx levels in the range of 0.1 to 1.0 g/bhp-hr have been achieved." Although this is consistent with the statement in the Draft Report that NSCR can achieve NOx emissions of less than 2 g/hp-hr, tighter control levels can certainly be achieved in retrofitting rich burn engines with a well controlled NSCR system. 2. Not all rich-burn engines would need to be retrofitted to NSCR to achieve the reductions postulated in the Draft Report. For example, if 57% of the under-100-hp engines in New Mexico were retrofitted with NSCR, which achieves less than 2 g/hp-hr NOx emissions (this is a conservative number, since NOx emissions that are well under 1 g/hp-hr are possible), then the overall emissions rate for that class of engine would decrease from 16 g/hp-hr to 8 g/hp-hr. According to Table 7 in the Draft Report, this would mitigate 6337 tons/yr of NOx (6694 tons/yr with growth). Since only 57% of the engines in this classification would need to be retrofitted, a retrofit kit would need to be developed only for the most common engine model (or a few models, at most.) This would save the expense of engineering development for engine models that have only a few examples represented in the Four Corners area and would concentrate the engineering effort where it would do the greatest amount of good. If more that 57% of the engines were controlled at the 2 g/hp-hr level, then more that 6337 tons/yr of NOx would be mitigated, but the incremental cost per tons/yr of NOx would be higher than that of the first 6337 tons/yr. It should also be noted that if the 57% of engines with NSCR controlled NOx at the 1 g/hp-hr rather than 2 g/hp-hr, 6773 tons/yr of NOx world be mitigated. This is an additional 436 tons/yr. A number of issues are identified with the use of NSRC on small engines. All of these issues, including ammonia formation, can be eliminated or minimized through use of a NSCR retrofit package that includes all the right components. The appropriate NSCR retrofit kit should include: - A 3-way catalytic converter - Exhaust oxygen sensor - Replace existing carburetor with a controllable air/fuel ratio (AFR) controller device. The ratio of an engine's actual AFR to the stoichiometric AFR for the fuel being used is referred to as the Lambda parameter. To ensure that exhaust bound O_2 comprises no more that 0.5% (by volume) of the total engine exhaust, rich burn engines operate at λ's of between 0.988 and 0.992 (Chapman, 2004b). (For engines burning clean, dry natural gas, the air to fuel ratio (AFR) for stoichiometry is ~16.1:1, Chapman, 2004a). - Computerized control using feedback from the exhaust oxygen sensor to control the air/fuel ratio λ's of between 0.988 and 0.992 with the retrofitted NSCR system. - Exhaust gas recirculation (EGR) and controllable ignition timing could also be included and controlled by the same computer. Both EGR and retarded ignition timing reduce engine-out NOx emissions and enhance the effectiveness of the catalyst. Retarded ignition timing also has the effect of increasing exhaust temperature, which will improve the effectiveness of the catalyst at light engine	Use of NSCR for NOx Control on Rich Burn Engines

Comment	Mitigation Option
loads. Although considerable engineering effort is required to develop the retrofit kit, it needs to be done for only one engine model or a few engine models, at most. In the 3rd parg. under engines < 100 hp, it states; "Also, research indicates that if the AFR drifts off the optimal setting, then NOx emissions may be converted (on an equal basis) to ammonia. If this occurs within the discharge plume of an engine, it may accelerate the conversion of NOx emissions into particulate nitrate. This is the reason that the carburetor must be replaced with a more accurate AFR controller having feedback from an exhaust oxygen sensor. With such a system, accurate AFR control is achieved, and generation of ammonia is not an issue. ___________________________________ Chapman, K., 2004a, Report 6: Cost-Effective Reciprocating Engine Emissions Control and Monitoring for E&P Field and Gathering Engines, Technical Progress Report, DOE Award DE-FC26-02NT15464, Kansas State University, August Chapman, K., 2004b, Report 4: Cost-Effective Reciprocating Engine Emissions Control and Monitoring for E&P Field and Gathering Engines, Technical Progress Report, DOE Award DE-FC26-02NT15464, Kansas State University, January	
The assumption of 50% reduction of NOx in the Draft Report is too pessimistic or small. Other information indicates that NOx reduction greater than 90% is achievable. Another report indicated 95.9% NOx reduction on a 320 kW (430 hp) natural-gas fueled engine. The same report gave costs of $2,205-$3,684 per ton of NOx removed. This is considerably less than the $10,300 per ton of NOx removed indicated in the Draft Report. Another report indicated that the cost of SCR on reciprocating natural-gas engines varied from $30-$250 per horsepower with no correlation to engine size. Considering that the date of the fourth report is 1990, one reason for the variation in cost may be lack of experience on the part of some installers. Using the same methodology that was used in the Draft Report, but allowing a 90% NOx reduction on new engines instead of 50% gives a reduction of 1789 tons/year (16.5% reduction of overall NOx) in Colorado and a reduction of 2015 tons/year (4.6% reduction of overall NOx in New Mexico. The 90% NOx reduction should be achievable with good operation and maintenance practice in light of the 95.9% NOx reduction already achieved in the field. These figures were for new engines greater than 500 hp. Since the reported engine was smaller than 500 hp, the same calculation was performed for new engines greater than 300 hp. These gave a reduction of 2,109 tons/year (19.5%) in Colorado and 2502 tons/year (5.8%) in New Mexico. The engines with SCR would have NOx emissions of about 0.1 g/hp-hr. ____ 1. Jim McDonald and Xavier Palacios, "Compressor Tech 2: SCR for Gaz de France," Miratech Corporation, Tulsa, OK, December 1, 2002. 2. Johnson Matthey Corp., "Maximum NOx Control for Stationary Diesel and Gas Engines," brochure number "jm_brochure_scr_062306b.pdf". 3. Ravi Krishnan, RJM Corp., "Urea-based SCR technology achieves 12 ppm NOx on natural gas engine," PennWell Power Group Online Article available at http://pepei.pennet.com/Articles/Article_Display.cfm?ARTICLE_ID=156191,	Use of SCR for NOx Control on Lean Burn Engines

Comment	Mitigation Option
October 1, 2002. 4. G.S. Shareef and D.K. Stone, "Evaluation of SCR NOx controls for small natural gas-fueled prime movers. Phase 1. Topical Report," report number PB-90-270398/XAB; DCN-90-209-028-11; GRI-5089-254-1899, Radian Corp., Research Triangle Park, NC, July 1, 1990.	
The first paragraph of the section on Next Generation RICE Stationary Technology in the Draft Report does not give adequate weight to the importance of next generation technology. As emissions regulations become tighter (e.g., 0.2 g/hp-hr NOx in 2010), those limits will become increasingly difficult to meet with existing technology. Continuing research on advanced technologies is necessary to ensure than ever tighter limits in the future can be met. Three of the technologies listed below, NOx trap catalysts, laser ignition, and HCCI, are close to meeting the 0.2 g/hp-hr limit by themselves. Two of the technologies, laser ignition and HCCI, may be able to meet the 0.2 g/hp-hr limit without aftertreatment. With aftertreatments they may be able to meet an even lower limit. NOx trap catalysts are an aftertreatment that offers the same performance as SCR, but with potentially lower cost. Air separation membranes may be used in combination with other technologies to outperform the 0.2 g/hp-hr limit. NOx trap catalysts are similar in performance to SCR, that is they can reduce more than 90% of the engine-out NOx to achieve less than 1 g/hp-hr NOx emissions.[1] The estimates of NOx abatement used in the Cumulative Effects SCR section of the draft report may be used as a guide to the abatement potential of NOx trap catalysts. The cost is expected to be less than that of SCR because ammonia or urea is not used as a reductant. Instead, some of the fuel is used as a reductant. The increase in fuel consumption may be up to 8%, but is typically about 4%. Air separation membranes used to deplete oxygen from the intake air have an effect on NOx emissions that is similar to that of exhaust gas recirculation (EGR) in rich-burn and diesel engines. Combined with ignition retardation, a reduction in engine-out NOx of up to 40% can be expected.[2,3] For engines in the 300-500 hp range, air separation membranes with ignition retard could reduce overall NOx emissions to 2 g/hp-hr in both Colorado and New Mexico. For the 100-300 hp range, these technologies could reduce overall NOx emissions from 16.3 to 10 g/hp-hr in Colorado and from 12.5 to 7.5 g/hp-hr in New Mexico. For engines under 100 hp, the technologies could reduce overall NOx emissions from 13.4 to 8 g/hp-hr in Colorado and from 16 to 9.6 g/hp-hr. Laser ignition may be able to reduce NOx emissions by as much as 70% in lean burn engines.[4] However, in the reference cited, the baseline emissions for the engine with spark ignition were higher than the emissions that are currently achievable with lean burn engines. Additional development and testing will be required to verify the reduction of NOx emissions. There is little information in the literature about lean NOx catalysts used with lean burn natural gas engines. Information about lean NOx catalysts used with diesel engines indicates NOx reductions of 10-40% depending on whether fuel is used as a reductant.[5,6] NOx reductions for lean burn natural gas engines is expected to be similar. Although researchers are attempting to improve the conversion efficiency of lean NOx catalysts, their current low performance makes them unsuitable for the short term. Only a few experimental measurements of NOx from homogeneous-charge	Next Generation Stationary RICE Technology

Comment	Mitigation Option
compression-ignition (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.[7] Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.[8] Whether HCCI technology can be applied to all engine types and sizes is not known. In addition, the ultimately achievable NOx emissions from such engines is not known. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option. ____________________________ 1 James E. Parks II, Douglas Ferguson III, and John M. E. Storey, "NOx Reduction With Natural Gas for Lean Large-Bore Engine Applications Using Lean NOx Trap Aftertreatment." Oak Ridge National Laboratory, 2360 Cherahala Blvd., Oak Ridge, TN 37932. 2 K. Stork and R. Poola, "Membrane-Based Air Composition Control for Light-Duty Diesel Vehicles: A Cost and Benefit Assessment," Report Number ANL/ESD/TM-144, Argonne National Laboratory, 9700 South Cass Avenue, Argonne, IL 60439, October 1998. 3 Joe Kubsh, "Retrofit Emission Control Technologies for Diesel Engines," NAMVECC 2003, Manufacturers of Emission Controls Association, www.meca.org, Chattanooga, TN, November 4, 2003. 4 B. Bihari, S. B. Gupta, R. R. Sekar, J. Gingrich, and J. Smith, "Development of Advanced Laser Ignition System for Stationary Natural Gas Reciprocating Engines," ICEF2005-1325, ASME-ICE 2005 Fall Technical Conference, Ottawa, Canada, 2005. 5 Joe Kubsh, op.cit. 6 Carrie Boyer, Svetlana Zemskova, Paul Park, Lou Balmer-Millar, Dennis Endicott, and Steve Faulkner, "Lean NOx Catalysis Research and Development", Caterpillar Inc., presented at the 2003 Diesel Engine Engineering Research Conference. 7 Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc. 8 Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002.	
The SUGF recommends further examination of the above listed mitigation options as particulates associated with each option contribute to local visibility issues.	Automation of Wells to Reduce Truck Traffic Reduced Truck Traffic by Centralizing Produced Water Storage Facilities

Monitoring

MONITORING: PREFACE

Overview
The charter for the Monitoring Workgroup was as follows:

> "The monitoring workgroup will review information provided on existing monitoring networks, and then identify data gaps and options for additional monitoring in cooperation with the other work groups. A gap analysis and trends analysis will be the basis for identifying options for additional monitoring. The monitoring workgroup will identify potential funding sources and develop a holistic monitoring strategic plan for the region."

Group Membership
The Monitoring Group was quite diverse. Members included private citizens from the Durango-Cortez-Aztec area, National Park Service personnel, U. S. Forest Service personnel, the Director of Research and Education at Mountain Studies Institute, a University of Denver graduate student, Tribal air quality personnel (Southern Ute and Navajo Nation), a private consulting hydrologist, air quality staff from two state agencies (New Mexico and Colorado), and personnel from two EPA regions (VI and VIII), among others.

Scope of Work
The following scope of work, including "specific tasks" and "discussion" for the Monitoring Group, was established at the onset of the Task Force.

Specific Tasks
D. Identify existing monitoring networks located in the Four Corners study area. Review information provided by these networks to identify data gaps.
E. Conduct data analyses to determine pollutant trends within the Four Corners study area.
F. Using the gap analysis and trend analysis, identify options for additional monitoring.
G. Incorporate public input when developing a monitoring strategy.
H. Identify potential funding sources for additional monitoring sites.
I. Develop final monitoring strategies for the Four Corners study area.

Discussion
The work group examined the various agency monitoring networks to determine present monitor locations and types, and pollutants or parameters being measured. Using this evaluation the work group identified locations within the study area that lack adequate representation in terms of pollutant data. Available data from the monitoring networks were analyzed to establish pollutant trends. The method and extent of establishing additional monitoring capabilities was dictated by the results from the network studies and from the data analyses. Public input was also addressed during the consideration of potential monitoring site locations. Once it had been established where monitoring sites were needed and what pollutants or parameters were to be measured, the work group identified potential funding sources.

Task 1
In identifying the existing monitoring networks located in the Four Corners study area, a matrix was developed. The matrix attempted to list all known air pollutant monitoring sites and meteorological monitoring sites within the study area. The type of site and the parameters measured at that site were listed in the matrix. The matrix was comprised of four spreadsheets; one having "site information", one having the "criteria sites", one having the "deposition sites", and one having the "meteorological sites".

Task 2
Data from agency databases were used to generate wind and pollution roses, and to generate graphs of pollutant trends. "Overlays" of pollution roses on both political boundary maps and on topographic maps have been produced. The trend graphs plot various pollutant concentrations since 1990.

Task 3
Once the gap analysis and the data analyses had been conducted, the work group assessed the types of monitors required and optimal site locations in the Four Corners study area.

Task 4

Because public sentiment and concern regarding air quality was of great importance to the Four Corners Air Quality Task Force, available public input was considered prior to any final suggestions of site location and type. Some of this input came from public citizens who are part of the task force.

Task 5

To provide the public with some idea of what it takes to set up a new monitoring site, two spreadsheets were created to show both capital and operating costs of two different agency sites. The work group identified potential funding sources for additional monitoring sites.

Task 6

A variety of monitoring strategies/suggestions were developed. These included ozone and ozone precursors, mercury, nitrate and sulfate, and visibility.

EXISTING MONITORING NETWORKS

Monitoring Site Matrix Narrative
The Four Corners Area Monitoring Site Matrix is an attempt to list all of the various air quality monitoring sites in the Four Corners area as well as the predominant meteorological monitoring sites. The following explanations refer to the major column headers of the various matrix pages.

Monitoring Programs
All of the air quality programs are represented in the matrix (some sites are under multiple programs) and are listed below. The following descriptions of the programs are from each program's web site:

ARM-FS: Air Resource Management, USDA Forest Service
The Real-Time Images section features live images and current air quality conditions from USDA-FS monitoring locations throughout the United States. Digital images from Web-based cameras are updated every 15 to 60 minutes. Near real-time air quality data and meteorological data are also provided to distinguish natural from human-made causes of poor visibility, and to provide current air pollution levels to the public.

CASTNET: Clean Air Status and Trends Network, EPA
CASTNET provides atmospheric data on the dry deposition component of total acid deposition, ground-level ozone and other forms of atmospheric pollution. CASTNET is considered the nation's primary source for atmospheric data to estimate dry acidic deposition and to provide data on rural ozone levels. Used in conjunction with other national monitoring networks, CASTNET can help determine the effectiveness of national emission control programs.

Each CASTNET dry deposition station measures:

- weekly average atmospheric concentrations of sulfate, nitrate, ammonium, sulfur dioxide, and nitric acid;
- hourly concentrations of ambient ozone levels; and
- meteorological conditions required for calculating dry deposition rates.

CoAgMet: Colorado Agricultural Meteorological Network
In the early 1990's, two groups on the Colorado State campus, the Plant Pathology extension specialists and USDA's Agricultural Research Service (ARS) Water Management Unit, discovered that they had a mutual interest in collecting localized weather data in irrigated agricultural area. Plant pathology used the data for prediction of disease outbreaks in high value crops such as onions and potatoes, and ARS used almost the same information to provide irrigation scheduling recommendations.

To leverage their resources, these two formed an informal coalition, and invited others in the ag research community to provide input into the kinds and frequency of measurements that would be most useful to a broad spectrum of agricultural customers. A standardized set of instruments was selected, a standard datalogger program was developed, and a fledgling network of some eight stations was established in major irrigated areas of eastern Colorado. As interest grew and funds were made available, primarily from potential users, more stations were added.

Initially, stations were located near established phone service to allow daily collection of data. Soon, cellular phone service began to become widely available, and the group determined that this methodology was a reliable and inexpensive method of data recovery. Commercial software was used to download data from the growing list of stations shortly after midnight to a USDA-ARS computer, from which it was then distributed to interested users via answering machine, automated FAX and satellite downlink (Data Transmission Network).

As the network grew, Colorado Climate Center at Colorado State became interested in these data, and subsequently took over the daily data collection and quality assessment. CCC added internet delivery and a wide range of data delivery options, and continues to improve the user interface in response to a growing interest in these data.

IMPROVE: Interagency Monitoring of Protected Visual Environments
Recognizing the importance of visual air quality, Congress included legislation in the 1977 Clean Air Act to prevent future and remedy existing visibility impairment in Class I areas. To aid the implementation of this legislation, the IMPROVE program was initiated in 1985. This program implemented an extensive long term monitoring program

to establish the current visibility conditions, track changes in visibility and determine causal mechanism for the visibility impairment in the National Parks and Wilderness Areas.

NADP/NTN: National Atmospheric Deposition Program, National Trends Network
The National Atmospheric Deposition Program/National Trends Network (NADP/NTN) is a nationwide network of precipitation monitoring sites. The network is a cooperative effort between many different groups, including the State Agricultural Experiment Stations, U.S. Geological Survey, U.S. Department of Agriculture, and numerous other governmental and private entities. The NADP/NTN has grown from 22 stations at the end of 1978, our first year, to over 250 sites spanning the continental United States, Alaska, and Puerto Rico, and the Virgin Islands.

The purpose of the network is to collect data on the chemistry of precipitation for monitoring of geographical and temporal long-term trends. The precipitation at each station is collected weekly according to strict clean-handling procedures. It is then sent to the Central Analytical Laboratory where it is analyzed for hydrogen (acidity as pH), sulfate, nitrate, ammonium, chloride, and base cations (such as calcium, magnesium, potassium and sodium).

NADP/MDN: National Atmospheric Deposition Program, Mercury Deposition Network
The Mercury Deposition Network (MDN), currently with over 90 sites, was formed in 1995 to collect weekly samples of precipitation which are analyzed by a prominent laboratory for total mercury. The objective of the MDN is to monitor the amount of mercury in precipitation on a regional basis; information crucial for researchers to understand what is happening to the nation's lakes and streams.

NWS: National Weather Service
Feb. 9, 2005 - The NOAA National Weather Service is celebrating its 135th anniversary amid a renewed commitment to preserve its history.

On February 9, 1870, President Ulysses S. Grant signed a joint resolution of Congress authorizing the Secretary of War to establish a national weather service. Later that year, the first systematized, synchronous weather observations ever taken in the U.S. were made by "observer sergeants" of the Army Signal Service.

Today, thousands of weather observations are made hourly and daily by government agencies, volunteer/citizen observers, ships, planes, automatic weather stations and earth-orbiting satellites.

"Since the beginning, the mission of the National Weather Service to protect life and property has been and remains to be the top priority," said Brig. Gen. David L. Johnson, U.S. Air Force (Ret.), director of NOAA's National Weather Service. "Advances in research and technology through the decades have allowed the NOAA National Weather Service to create an expanding observational and data collection network that tracks Earth's changing systems."

RAWS: Remote Automated Weather Stations
There are nearly 2,200 interagency Remote Automated Weather Stations (RAWS) strategically located throughout the United States. These stations monitor the weather and provide weather data that assists land management agencies with a variety of projects such as monitoring air quality, rating fire danger, and providing information for research applications.

SLAMS: State/Local Air Monitoring Stations
These ambient air monitoring sites are designated by EPA as State/Local Air Monitoring Stations (SLAMS). Pollutants monitored are the criteria pollutants, and include ozone, particulate matter, carbon monoxide, lead, sulfur dioxide, and oxides of nitrogen.

SPMS: Special Purpose Monitoring Stations
Special Purpose Monitoring Stations provide for special studies needed by the State and local agencies to support State implementation plans and other air program activities. The SPMS are not permanently established and, can be adjusted easily to accommodate changing needs and priorities. The SPMS are used to supplement the fixed monitoring network as circumstances require and resources permit. If the data from SPMS are used for SIP purposes, they must meet all QA and methodology requirements for SLAMS monitoring.

Tribal: Tribal Jurisdiction
These sites are under tribal jurisdiction and are the tribal equivalent to SLAMS sites, monitoring the same criteria pollutants.

Period of Record
The period of record refers to how long a site has been in operation. In some cases, dates refer to monitoring of major parameters at a site.

In the case of the NWS sites, the "start" dates are the dates when the NWS data was inserted into the MesoWest database which is maintained by the University of Utah's Department of Meteorology.

Distance From
The distances listed refer to the distance from each monitoring site to two representative Four Corners cities; one in Colorado and one in New Mexico. The distances were obtained either from Argonne National Lab's interactive Four Corners Aerometric Map or Google Maps. Other "site-to-city" distances can be determined by using either map.

Criteria Pollutants
EPA uses six "criteria pollutants" as indicators of air quality, and has established for each of them a maximum concentration above which adverse effects on human health may occur. Explanations of these pollutants can be found on EPA's "Green Book" website,
http://www.epa.gov/oar/oaqps/greenbk/o3co.html

Meteorological
These columns indicate what meteorological parameters are monitored at a given site. The parameters are: wind (usually speed and direction), temperature (usually 2-meter and 10-meter), delta T (the difference between 2-meter and 10-meter), solar radiation, relative humidity, and precipitation.

Deposition
The parameters refer to those monitored by The National Atmospheric Deposition Program/National Trends Network (NADP/NTN).

The passive ammonia sampling sites are also listed on the "Deposition" page.

Key to Matrix Symbols
The following explanation refers to the various symbols used within the matrix cells.

h: Sampled and/or averaged hourly
1d/3d: Sampled once every three days
1d/6d: Sampled once every six days
w: Sampled weekly
3w: Sampled every three weeks

Monitoring Site General Information

Site	Program	Address	AQS / Other Code	Period of Record From	Period of Record To	Latitude	Longitude	Elevation (meters)	Distance from: (Km) Farmington	Distance from: (Km) Durango
Substation	SLAMS	16 mi. NW of Farmington, NM	35-045-1005	01/01/72	Present	36.7967	-108.4803	1643	24.2	73.9
Bloomfield	SLAMS	162 Highway 550 ; Bloomfield, NM	35-045-0009	08/01/77	Present	36.7421	-107.9773	1618	19.4	59.8
Navajo Lake	SLAMS	423 Highway 539 ; Navajo Lake, NM	35-045-0018	07/01/05	Present	36.8098	-107.6514	1950	49.3	56.4
Farmington	SLAMS	724 W Animas ; Farmington, NM	35-045-0006	08/01/77	Present	36.7273	-108.2152	1643	0.0	66.7
S.Ute 3 - Bondad	Tribal	7571 Highway 550 ; La Plata County, CO	08-067-7003	04/01/97	Present	37.1025	-107.8703	1920	50.5	19.3
S.Ute 1 - Ignacio	Tribal	County Road 517 ; La Plata County, CO	08-067-7001	06/01/82	Present	37.1389	-107.6317	1981	67.7	25.8
Shamrock Site	ARM-FS IMPROVE	8 mi. NE of Bayfield, CO	08-067-9000 SHMI1	02/01/04 08/01/04	Present Present	37.3038	-107.4842	2351	90.3	34.3
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN NADP/MDN	Chapin Mesa, Mesa Verde Nat'l Park, Montezuma County, CO	MEV405 MEVE 1 08-038-0101 CO99 CO99	01/10/95 03/05/94 07/23/06 04/28/81 12/26/01	Present Present Present Present Present	37.1984	-108.4907	2165	57.1	54.3
Pagosa Springs – School	SLAMS	309 Lewis St., Pagosa Springs, CO	08-007-0001	08/01/75	Present	37.2681	-107.0211	2168	121.9	74.8
Durango – Courthouse	SLAMS	1060 E. 2nd Ave., Durango, CO	08-067-1001	03/01/87	12/31/06	37.2739	-107.8786	1984	66.9	0.1
Durango – River City	SLAMS	1235 Camino del Rio, Durango, CO	08-067-0004	09/01/85	Present	37.2769	-107.8806	1985	66.8	0.3
Durango – Tradewinds	SLAMS	1455 S. Camino del Rio, Durango, CO	08-067-0009	10/30/03	04/06/05	37.2187	-107.8516	1973	63.1	3.9
Durango – Cutler	SLAMS	177 Cutler Dr., Durango, CO	08-067-0010	10/30/03	04/30/06	37.3082	-107.8456	1992	70.9	4.3
Durango – Grandview	SLAMS	56 Davidson Rd., Durango, CO	08-067-0011	07/01/04	12/31/06	37.2295	-107.8267	2044	67.6	6.8
Telluride	SLAMS	333 W. Colorado Ave., Telluride, CO	08-113-0004	03/01/90	Present	37.9375	-107.8117	2694	140.6	76.3
Durango Mt. Resort	Other	Hwy. 550 & Purgatory Drive	---	10/11/02	Present	37.6314	-107.8076	2665	105.1	38.9
Wolf Creek Pass	NADP/NTN	Mineral County, CO	CO91	05/26/92	Present	37.4686	-106.7903	3292	148.8	98.6
Molas Pass	NADP/NTN	San Juan County, CO	CO96	07/29/86	Present	37.7514	-107.6853	3249	121.2	56.4

Site	Program	Address	AQS / Other Code	Period of Record		Latitude	Longitude	Elevation (meters)	Distance from: (Km)	
				From	To				Farmington	Durango
Weminuche	IMPROVE	30 mi. N of Durango, CO	WEMI1	03/02/88	Present	37.6594	-107.7999	2750	110.6	44.0
San Pedro Parks	IMPROVE	6 mi E of Cuba, NM	SAPE1	08/15/00	Present	36.0139	-106.8447	2935	133.6	160.4
Fort Defiance	Tribal	Rte. 12 N, Bldg. F-004-051, Fort Defiance, AZ	04-001-1234	01/01/99	Present	35.7460	-109.0717	2090	135.4	200.4
Shiprock Dine College	Tribal	Dine College, GIS Lab, Shiprock, NM	35-045-1233	01/01/03	Present	36.8071	-108.6952	1525	45.0	141.1
Canyonlands NP	CASTNET NADP/NTN IMPROVE	"Island of the Sky" Visitor's Center, Canyonlands Nat'l Park, San Juan County, UT	CAN407 UT09 CANY1	01/24/95 11/11/97 03/02/88	Present Present Present	38.4580	-109.821	1814	239.8	214.6
Arches NP	IMPROVE	14 mi N of Moab, UT	ARCH1	03/02/88	05/16/92	38.7833	-109.5830	1722	253.6	217.2
Moab #6	SLAMS	168 West 400 North, Moab, UT	49-019-0006	10/21/93	6/30/03	38.5795	-109.5540			
Petrified Forest NP (Old)	CASTNET IMPROVE SPMS	1 mi. N of park HQ	PET427 PEFO1 04-001-0012	? 03/02/88 10/27/86	Present Present 04/16/92	35.0772	-109.7697	1766	262.9	329.2
Petrified Forest NP (New)	SPMS	SW Entrance; off Rte. 180	04-017-0119	01/01/88	Present	34.8230	-109.8919	1723	265.5	331.5
Rainbow Forest NP	NADP/NTN	Apache County, AZ	AZ97	12/03/02	Present	35.0013	-109.0128	1707	207.5	274.1
Alamosa	NADP/NTN	Alamosa county, CO	CO00	04/22/80	Present	37.4414	-105.8653	2298	221.0	177.6
Great Sand Dunes NP	IMPROVE	Monument HQ, Saguache County, CO	GRSA1	05/04/88	Present	37.7249	-105.5185	2498	258.0	207.1
Big Horn	RAWS	Conejos County, CO	BHRC2	05/13/93	Present	37.0208	-106.2011	2637	175	147
Sand Dunes	RAWS	Alamosa County, CO	SDNC2	06/02/04	Present	37.7267	-105.5108	2537	254	210
Lujan	RAWS	Saguache County, CO	LUJC2	09/13/94	Present	38.2544	-106.5678	3400	214	155
Needle Creek	RAWS	Saguache County, CO	NCKC2	09/05/02	Present	38.3894	-106.5308	2741	227	168
Huntsman Mesa	RAWS	Gunnison County, CO	HMEC2	05/22/91	Present	38.3319	-107.0889	2865	195	135
McClure Pass	RAWS	Gunnison County, CO	MPRC2	06/11/85	Present	39.1267	-107.2842	2761	264	205
Taylor Park	RAWS	Gunnison County, CO	TAPC2	10/27/87	Present	38.9086	-106.6028	3200	268	210
PSF2 Salida 555	RAWS	Chaffee County, CO	SIDC2	05/01/97	Present	38.7856	-105.9569	2932	291	229
Red Deer	RAWS	Chaffee County, CO	RDKC2	05/01/83	Present	38.8272	-106.2117	2660	280	218
Jay	RAWS	Delta County, CO	JAYC2	07/09/84	Present	38.8456	-107.7386	1890	227	168
Blue Park	RAWS	Mineral County, CO	BLPC2	04/24/90	Present	37.7931	-106.7786	3179	167	109
Black Canyon	RAWS	Montrose County, CO	LPRC2	06/04/97	Present	38.5428	-107.6869	2609	195	132
Carpenter Ridge	RAWS	Montrose County, CO	CPTC2	12/17/98	Present	38.4594	-109.0469	2465	195	160
Cottonwood Basin	RAWS	Montrose County, CO	CMEC2	05/23/91	Present	38.5731	-108.2778	2201	194	140

Site	Program	Address	AQS / Other Code	Period of Record		Latitude	Longitude	Elevation (meters)	Distance from: (Km)	
				From	To				Farmington	Durango
Nucla	RAWS	Montrose County, CO	NUCC2	05/21/98	Present	38.2333	-108.5617	1786	162	116
Sanborn Park	RAWS	Montrose County, CO	SPKC2	01/29/85	Present	38.1922	-108.2169	2417	153	101
Salter	RAWS	Dolores County, CO	SAWC2	05/30/85	Present	37.6511	-108.5369	2500	101	67
Devil Mtn.	RAWS	Archuleta County, CO	DYKC2	07/27/89	Present	37.2269	-107.3053	2274	92	50
Sandoval Mesa	RAWS	Archuleta County, CO	SDVC2	07/15/99	Present	37.0994	-107.3028	2588	86	53
Big Bear Park	RAWS	La Plata County, CO	BBRC2	08/26/05	Present	37.4961	-107.7294	3170	90	28
Mesa Mtn.	RAWS	La Plata County, CO	MMRC2	11/17/93	Present	37.0564	-107.7086	2249	54	25
SJF1 Durango 555	RAWS	La Plata County, CO	DUFC2	06/01/96	Present	37.3517	-107.9000	2502	72	9
Chapin	RAWS	Montezuma County, CO	CHAC2	09/07/99	Present	37.1994	-108.4892	2172	55	51
Mockingbird	RAWS	Montezuma County, CO	MOKC2	08/24/05	Present	37.4744	-108.8842	1957	99	87
Morefield	RAWS	Montezuma County, CO	MRFC2	11/12/99	Present	37.2972	-108.4128	2383	61	45
Albino Canyon	RAWS	San Juan County, NM	CWRN5	09/27/83	Present	36.9769	-107.6283	2182	55	35
Washington Pass	RAWS	San Juan County, NM	WPSN5	11/19/03	Present	36.0781	-108.8575	2856	86	147
Coyote	RAWS	Rio Arriba County, NM	COYN5	08/07/96	Present	36.0667	-106.6472	2682	149	161
Deadman Peak	RAWS	Rio Arriba County, NM	DPKN5	05/23/00	Present	36.4231	-107.7719	2575	46	129
Dulce #2	RAWS	Rio Arriba County, NM	DLCN5	07/07/05	Present	36.9350	-107.0000	2070	107	79
Jarita Mesa	RAWS	Rio Arriba County, NM	JARN5	04/15/02	Present	36.5558	-106.1031	2683	183	168
Stone Lake	RAWS	Rio Arriba County, NM	STLN5	07/07/05	Present	36.7314	-106.8647	2268	115	103
Zuni Buttes	RAWS	McKinley County, NM	ZNRN5	04/04/06	Present	35.1392	-108.9414	2039	172	236
Alb Portable #2	RAWS	McKinley County, NM	TSO43	11/18/03	Present	35.5264	-107.3211	2481	138	182
Bryson Canyon	RAWS	Grand County, UT	BCRU1	09/03/87	Present	39.2789	-109.2211	1621	283	241
Big Indian Valle	RAWS	San Juan County, UT	BIVU1	09/02/87	Present	38.2244	-109.2783	2121	182	153
Kane Gulch	RAWS	San Juan County, UT	KAGU1	06/20/91	Present	37.5247	-109.8931	1981	165	174
North Long Point	RAWS	San Juan County, UT	NLPU1	08/13/97	Present	37.8547	-109.8389	2646	182	175
Piney Hill	RAWS	Apache County, AZ	QPHA3	11/19/03	Present	35.7611	-109.1675	2469	126	187
Cortez	CoAgMet	9 mi. SW of Cortez, CO	CTZ01	04/24/91	Present	37.2248	-108.6730	1833	67	67
Dove Creek	CoAgMet	4 mi. NW of Dove Creek	DVC01	10/28/92	Present	37.7265	-108.9540	2010	123	104
Towaoc	CoAgMet	Ute Mtn Ute Farm	TWC01	06/30/98	Present	37.1891	-108.9350	1621	78	88
Yellow Jacket	CoAgMet	2.5 mi. NW of Yellow Jacket	YJK01	05/19/91	Present	37.5289	-108.7240	2103	94	77
Yucca House	CoAgMet	Yucca House National Monument	YUC01	01/01/02	Present	37.2478	-108.6870	1821	69	67
Cortez-Montezuma County Airport	NWS	3 mi. SW of Cortez, CO	KCEZ	01/01/97	Present	37.3064	-108.6256	1803	71	7

Site	Program	Address	AQS / Other Code	Period of Record		Latitude	Longitude	Elevation (meters)	Distance from: (Km)	
				From	To				Farmington	Durango
Cottonwood Pass	NWS	SW of Buena Vista, CO	K7BM	11/17/04	Present	38.7825	-106.2181	2995	280	215
Durango-La Plata County Airport	NWS	1000 Airport Road; Durango, CO	KDRO	01/01/97	Present	37.1431	-107.7597	2038	60	0
Gunnison-Crested Butte Regional Airport	NWS	519 W Rio Grande; Gunnison, CO	KGUC	01/01/97	Present	38.5333	-106.9333	2340	221	156
Montrose Regional Airport	NWS	2100 Airport Road ; Montrose, CO	KMTJ	01/01/97	Present	38.5050	-107.8975	1755	189	128
Pagosa Springs, Wolf Creek Pass	NWS	NE of Pagosa Springs, CO	KCPW	11/11/03	Present	37.4514	-106.8003	3584	145	95
Saguache Municipal Airport	NWS	2 mi. NW of Saguache, CO	04V	11/17/04	Present	38.0972	-106.1686	2385	227	171
Salida Mountain, Monarch Pass	NWS	W of Salida, CO	KMYP	09/10/03	Present	38.4844	-106.3169	3667	249	185
Telluride Regional Airport	NWS	1500 Last Dollar Road ; Telluride, CO	KTEX	02/05/97	Present	37.9539	-107.9086	2767	135	72
Farmington, Four Corners Regional Airport	NWS	800 Municipal Drive ; Farmington, NM	KFMN	01/01/97	Present	36.7436	-108.2292	1677	0	63
Grants-Milan Municipal Airport	NWS	3 mi. NW of Grants, NM	KGNT	04/11/97	Present	35.1653	-107.9022	1988	160	214
Gallup Municipal Airport	NWS	2111 W Hwy 66 ; Gallup, NM	KGUP	01/01/97	Present	35.5111	-108.7894	1973	133	194
Window Rock Airport	NWS	1 mi. S of Window Rock AZ	KRQE	11/14/99	Present	35.6500	-109.0667	2055	131	190
Moab, Canyonlands Field	NWS	18 mi. NW of Moab, UT	KCNY	01/01/97	Present	38.7600	-109.7447	1388	249	224

ARM-FS : Air Resource Management, USDA Forest Service
CASTNET : Clean Air Status and Trends Network, EPA
CoAgMet : Colorado Agricultural Meteorological Network
IMPROVE : Interagency Monitoring of Protected Visual Environments
NADP/NTN : National Atmospheric Deposition Program, National Trends Network
NADP/MDN : National Atmospheric Deposition Program, Mercury Deposition Network
NWS : National Weather Service
RAWS : Remote Automated Weather Stations
SLAMS : State/Local Air Monitoring Stations
SPMS : Special Purpose Monitoring Stations
Tribal : Tribal Jurisdiction

Criteria Pollutant Sites

Site	Program	Criteria Pollutants							
		O3	SO2	CO	NOx	NO	NO2	PM10	PM2.5
Substation	SLAMS	h	h		h	h	h		
Bloomfield	SLAMS	h	h		h	h	h		
Navajo Lake	SLAMS	h			h	h	h		h
Farmington	SLAMS							1d/6d	1d/3d
S.Ute 3 - Bondad	Tribal	h			h	h	h	ended 9/30/06	
S.Ute 1 - Ignacio	Tribal	h		h	h	h	h	ended 9/30/06	
Shamrock Site	ARM-FS IMPROVE	h	1d/3d		h 1d/3d	h	h	1d/3d	1d/3d
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN ADP/MDN	h	h 1d/3d		h 1d/3d			1d/3d	1d/3d
Pagosa Springs – School	SLAMS							1d/1d	1d/3d end 12/06
Durango – Courthouse	SLAMS							1d/3d end 12/06	
Durango- River City	SLAMS							1d/3d	
Durango – Tradewinds	SLAMS							1d/6d end 3/05	
Durango – Cutler	SLAMS							1d/6d end 4/06	
Durango - Grandview	SLAMS							1d/3d end 12/06	
Telluride	SLAMS							1d/3d	1d/3d end 12/06
Durango Mt. Resort	Other							h	
Weminuche	IMPROVE							1d/3d	1d/3d
San Pedro Parks	IMPROVE							1d/3d	1d/3d
Fort Defiance	Tribal							1d/6d	
Shiprock Dine College	Tribal							1d/6d	
Canyonlands NP	CASTNET NADP/NTN IMPROVE	h	h 1d/3d		h 1d/3d			1d/3d	1d/3d
Arches NP	IMPROVE		1d/3d		1d/3d				
Moab #6	SLAMS							1d/6d	
Petrified Forest NP (Old)	CASTNET IMPROVE SPMS	h h	h 1d/3d		h 1d/3d			1d/3d	1d/3d
Petrified Forest NP (New)	SPMS	h							
Great Sand Dunes NP	IMPROVE							1d/3d	1d/3d

See Monitoring Site General Information table for abbreviations
h : Sampled and/or averaged hourly
1d/1d : 24-hour sample taken every day
1d/3d : 24-hour sample taken every 3rd day
1d/6d : 24-hour sample taken every 6th day

Meteorological Sites

Site	Program	Wind	Temp	Delta T	Solar	RH	Precip
Substation	SLAMS	h	h	h	h		
Bloomfield	SLAMS	h	h	h	h		
Navajo Lake	SLAMS	h	h	h	h		
S.Ute 3 - Bondad	Tribal	h	h	h	h	h	h
S.Ute 1 - Ignacio	Tribal	h	h	h	h	h	h
Shamrock Site	ARM-FS IMPROVE	h	h		h	h	h
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN NADP/MDN	h	h	h	h	h	
Durango Mt. Resort	Other	h	h	h	h	h	h
Fort Defiance	Tribal	h	h		h	h	h
Shiprock Dine College	Tribal	h	h		h	h	h
Canyonlands NP	CASTNET NADP/NTN IMPROVE	h	h	h	h	h	
Petrified Forest NP (Old)	CASTNET IMPROVE	h	h	h	h	h	
Petrified Forest NP (New)	SPMS	h	h				
Big Horn	RAWS	h	h		h	h	h
Sand Dunes	RAWS	h	h		h	h	h
Lujan	RAWS	h	h		h	h	h
Needle Creek	RAWS	h	h		h	h	h
Huntsman Mesa	RAWS	h	h		h	h	h
McClure Pass	RAWS	h	h		h	h	h
Taylor Park	RAWS	h	h		h	h	h
PSF2 Salida 555	RAWS	h	h		h	h	h
Red Deer	RAWS	h	h		h	h	h
Jay	RAWS	h	h		h	h	h
Blue Park	RAWS	h	h		h	h	h
Black Canyon	RAWS	h	h		h	h	h
Carpenter Ridge	RAWS	h	h		h	h	h
Cottonwood Basin	RAWS	h	h		h	h	h
Nucla	RAWS	h	h		h	h	h
Sanborn Park	RAWS	h	h		h	h	h
Salter	RAWS	h	h		h	h	h
Devil Mtn.	RAWS	h	h		h	h	h
Sandoval Mesa	RAWS	h	h		h	h	h
Big Bear Park	RAWS	h	h		h	h	h
Mesa Mtn.	RAWS	h	h		h	h	h
SJF1 Durango 555	RAWS	h	h		h	h	h
Chapin	RAWS	h	h		h	h	h
Mockingbird	RAWS	h	h		h	h	h
Morefield	RAWS	h	h		h	h	h

Site	Program	Wind	Temp	Delta T	Solar	RH	Precip
Albino Canyon	RAWS	h	h		h	h	h
Washington Pass	RAWS	h	h		h	h	h
Coyote	RAWS	h	h		h	h	h
Deadman Peak	RAWS	h	h		h	h	h
Dulce #2	RAWS	h	h		h	h	h
Jarita Mesa	RAWS	h	h		h	h	h
Stone Lake	RAWS	h	h		h	h	h
Zuni Buttes	RAWS	h	h		h	h	h
Alb Portable #2	RAWS	h	h		h	h	h
Bryson Canyon	RAWS	h	h		h	h	h
Big Indian Valle	RAWS	h	h		h	h	h
Kane Gulch	RAWS	h	h		h	h	h
North Long Point	RAWS	h	h		h	h	h
Piney Hill	RAWS	h	h		h	h	h
Cortez	CoAgMet	h	h		h	h	
Dove Creek	CoAgMet	h	h		h	h	
Towaoc	CoAgMet	h	h		h	h	
Yellow Jacket	CoAgMet	h	h		h	h	
Yucca House	CoAgMet	h	h		h	h	
Cortez-Montezuma County Airport	NWS	h	h			h	
Cottonwood Pass	NWS	h	h			h	
Durango-La Plata County Airport	NWS	h	h			h	
Gunnison-Crested Butte Regional Airport	NWS	h	h			h	
Montrose Regional Airport	NWS	h	h			h	
Pagosa Springs, Wolf Creek Pass	NWS	h	h			h	
Saguache Municipal Airport	NWS	h	h			h	
Salida Mountain, Monarch Pass	NWS	h	h			h	
Telluride Regional Airport	NWS	h	h			h	
Farmington, Four Corners Regional Airport	NWS	h	h			h	
Grants-Milan Municipal Airport	NWS	h	h			h	
Gallup Municipal Airport	NWS	h	h			h	
Window Rock Airport	NWS	h	h			h	
Moab, Canyonlands Field	NWS	h	h			h	

See Monitoring Site General Information table for abbreviations
h: Sampled and/or averaged hourly

Deposition Sites

Site	Program	Deposition								
		NH3	pH	SO4	NH4	NO3	Pb	HF	Hg	Ca, Mg, K, Na, Cl
Substation	SLAMS	3w								
Navajo Lake	SLAMS	3w								
S.Ute 3 - Bondad	Tribal	3w								
Mesa Verde	CASTNET									
	IMPROVE									
	SPMS	3w								
	NADP/NTN		w	w	w	w				w
	NADP/MDN								w	w
Wolf Creek Pass	NADP/NTN		w	w	w	w				w
Molas Pass	NADP/NTN		w	w	w	w				w
Canyonlands NP	CASTNET									
	NADP/NTN		w	w	w	w				w
	IMPROVE									
Rainbow Forest NP	NADP/NTN		w	w	w	w				w
Alamosa	NADP/NTN		w	w	w	w				w
Farmington Airport	OTHER	3w								

See Monitoring Site General Information table for abbreviations
w : Sampled weekly
3w : Sampled every 3 weeks

DATA ANALYSIS AND RECOMMENDATIONS

Meteorology and Wind Roses

Background:

Rationale and Benefits:
Meteorology is the science that deals with the study of the atmosphere and its phenomena, especially with weather and weather forecasting. Meteorological conditions are a driving force in many bad pollution events and situations. These include stagnation, inversions and blowing dust. There are a number of components to meteorology, including wind speed, wind direction, temperature, relative humidity, barometric pressure, solar radiation, precipitation and others. Modeling is performed with the various components as part of forecasting for weather conditions as well as for air pollution impacts.

For air pollution, wind speed and wind direction are two of the more important components. These can determine how far pollution can be transported in a certain time period, if stagnation periods exist and what sources may have contributed to the air pollution. Wind roses are a simple visual way to depict wind speed strengths as a function of wind direction for a period of time. Wind roses are based on the direction that the wind is blowing from. Another way of visualizing a wind rose is to picture yourself standing in the center of the plot and facing into the wind. The wind direction is broken down in the 16 cardinal directions (i.e. N, NNE, NE, ENE, E, ESE, SE, SSE, S, etc). The wind speed is broken down into multiple ranges. The length of each arm of the wind rose represents the percentage of time the wind was blowing from that direction. The longer the arm, the greater percentage of time the wind is blowing from that direction. Since the occurrence of wind speeds of different ranges from a particular direction are stacked on the radius in order of increasing speeds, one must compare the length of each color to the distance between the percent circles to get the percent of time each range of wind speed occurred. The circles representing the percent of time can vary from rose to rose hence each rose must be checked for the values. Wind roses can be generated by a number of commercially available software programs. For this analysis, WRPLOT View from Lakes Environmental Software was employed.[1]

Existing meteorological data for the Four Corners region:
Meteorological data are collected at a number of different locations in the Four Corners region. Sites include State and Tribal agencies, the National Weather Service (NWS), the U.S. Forest Service (USFS), the National Park Service (NPS), The Remote Automated Weather Stations (RAWS) network, the Colorado Agriculture Meteorological Network (CoAgMet) and other private groups. Data are available from varying sources, including the U.S. Environmental Protection Agency's Air Quality System[2], the CoAgMet website[3], the New Mexico Environment Department website[4], the NWS website[5], the RAWS website[6] and from direct contact. For wind roses, hourly data (or more frequent) are needed. Ten-meter tall towers are a general standard that is used, though not all networks are set up this way. Maps of the meteorological sites that were used in this analysis are presented below, both for the whole Four Corners region and for a core area. These sites are a limited subset of the total number of possible sites, as can be seen in the site matrix tables in a different section of this overall report.

Wind roses were developed using hourly wind speed and wind direction data from 2006. Annual wind roses were developed as well at daytime (6:00 a.m. – 6:00 p.m.) and nighttime (6:00 p.m. – 6:00 a.m.). These wind roses were then overlaid on both political boundary maps and topographical maps (see annual/daytime/nighttime wind rose maps).

In looking at the annual wind roses, it is evident that some sites are more influenced by local topography than others. An example is the Cortez CoAgMet site, which is located in the valley between Sleeping Ute Mountain and Mesa Verde and is subjected to definite channeling effects. Another example is the U.S. Forest Service Shamrock site, which is located on the side of a hogback ridge. It can also be seen that the strongest winds are generally from a more westerly direction than an easterly one. From the daytime wind roses, there are general westerly or northerly/southerly components to the winds. In comparison, the nighttime wind roses show more of general easterly to northerly components. These trends are expected based on prevailing regional wind patterns as well as more local convection heating and cooling patterns along with topography.

These wind roses can be broken down even further, such as only for summer afternoon periods when ozone levels are expected to be highest (see summer afternoon wind rose maps). These wind roses show, in general, a predominant westerly to southwesterly component. As mentioned previously, some sites still exhibit wind patterns that are strongly influenced by local topography rather than more regional winds. However, these types of plots are useful in describing what may happen with air pollution flows during different periods of time. While not performed for this analysis, additional seasonal plots could be dome, such as for winter when inversions are more prevalent.

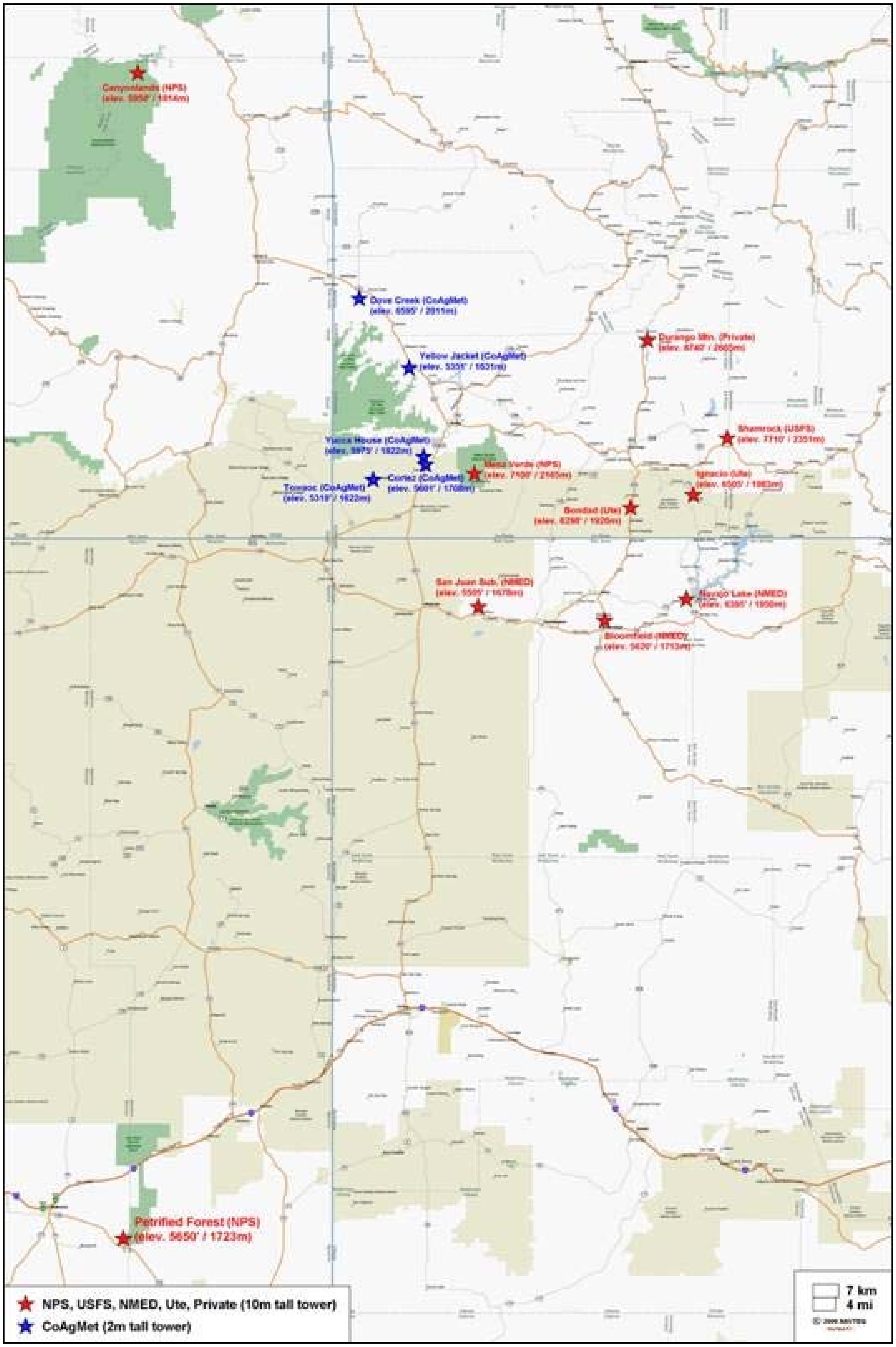
Data Gaps:
No significant data gaps exist for meteorological monitoring in the Four Corners region, with the exception of southwestern Utah and northeastern Arizona.

Suggestions for Future Monitoring Work:
No suggestions for additional monitoring of meteorological parameters are currently being proposed.

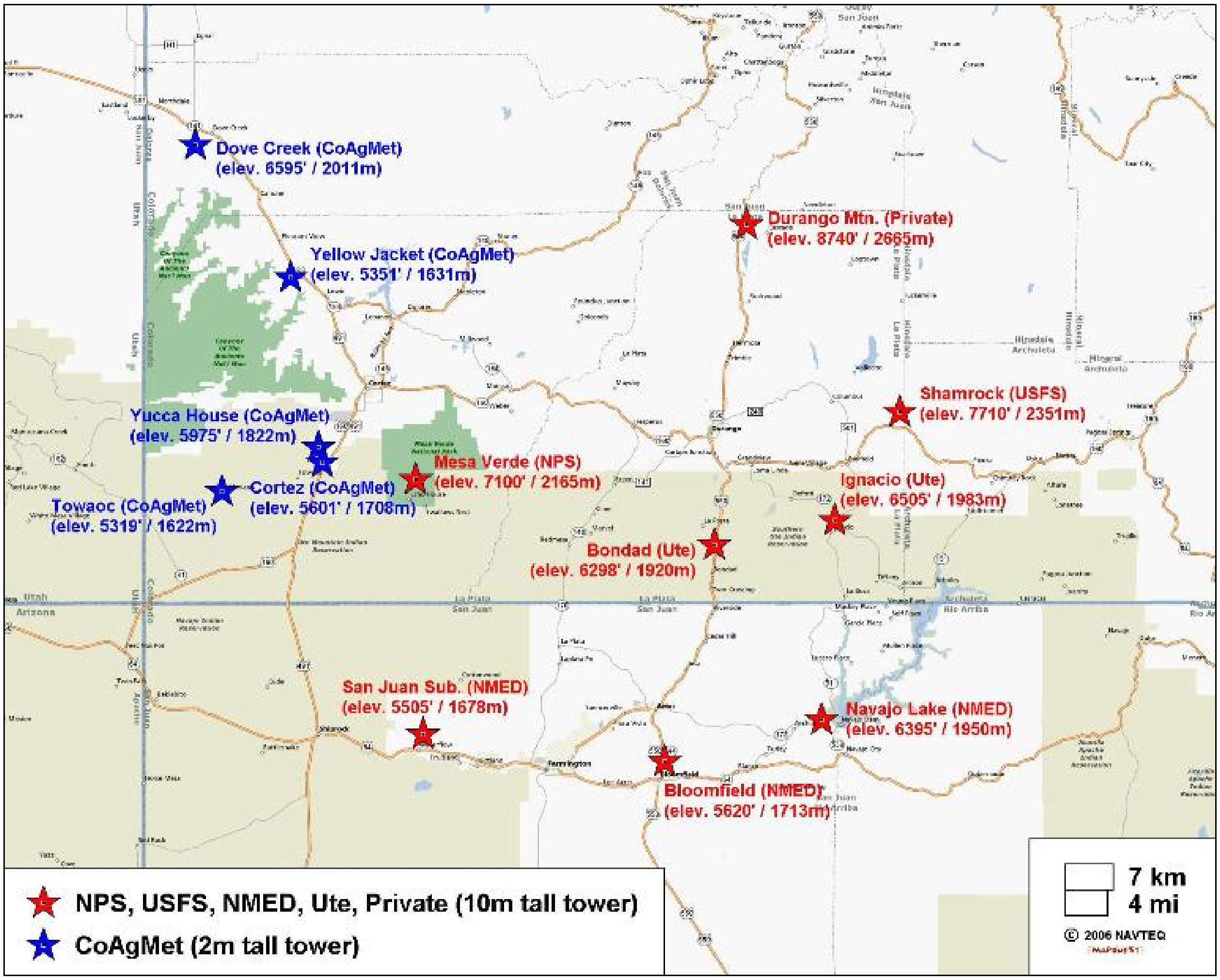
Literature Cited:

1. Lakes Environmental Software. WRPLOT View. http://www.weblakes.com/lakewrpl.html.
2. U.S. Environmental Protection Agency. http://www.epa.gov/air/data/index.html.
3. Colorado State University. Colorado Agriculture Meteorological Network. http://ccc.atmos.colostate.edu/~coagmet/.
4. New Mexico Environment Department. http://air.state.nm.us/.
5. National Weather Service. Automated Surface Observation System. http://www.nws.noaa.gov/asos/.
6. Western Regional Climate Center. Remote Automated Weather System. http://www.raws.dri.edu/index.html.

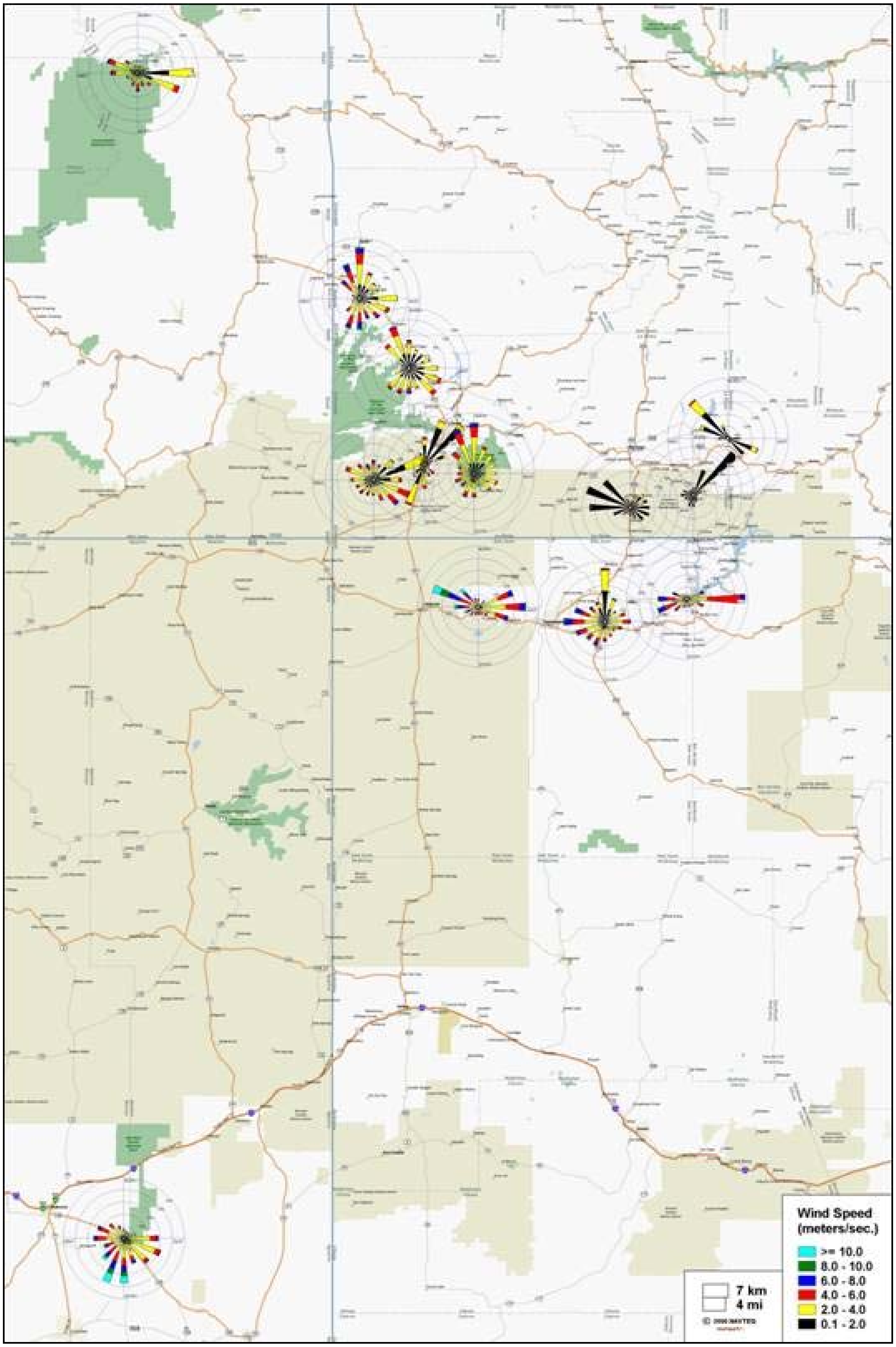
Four Corners --- Meteorological Sites in 2006



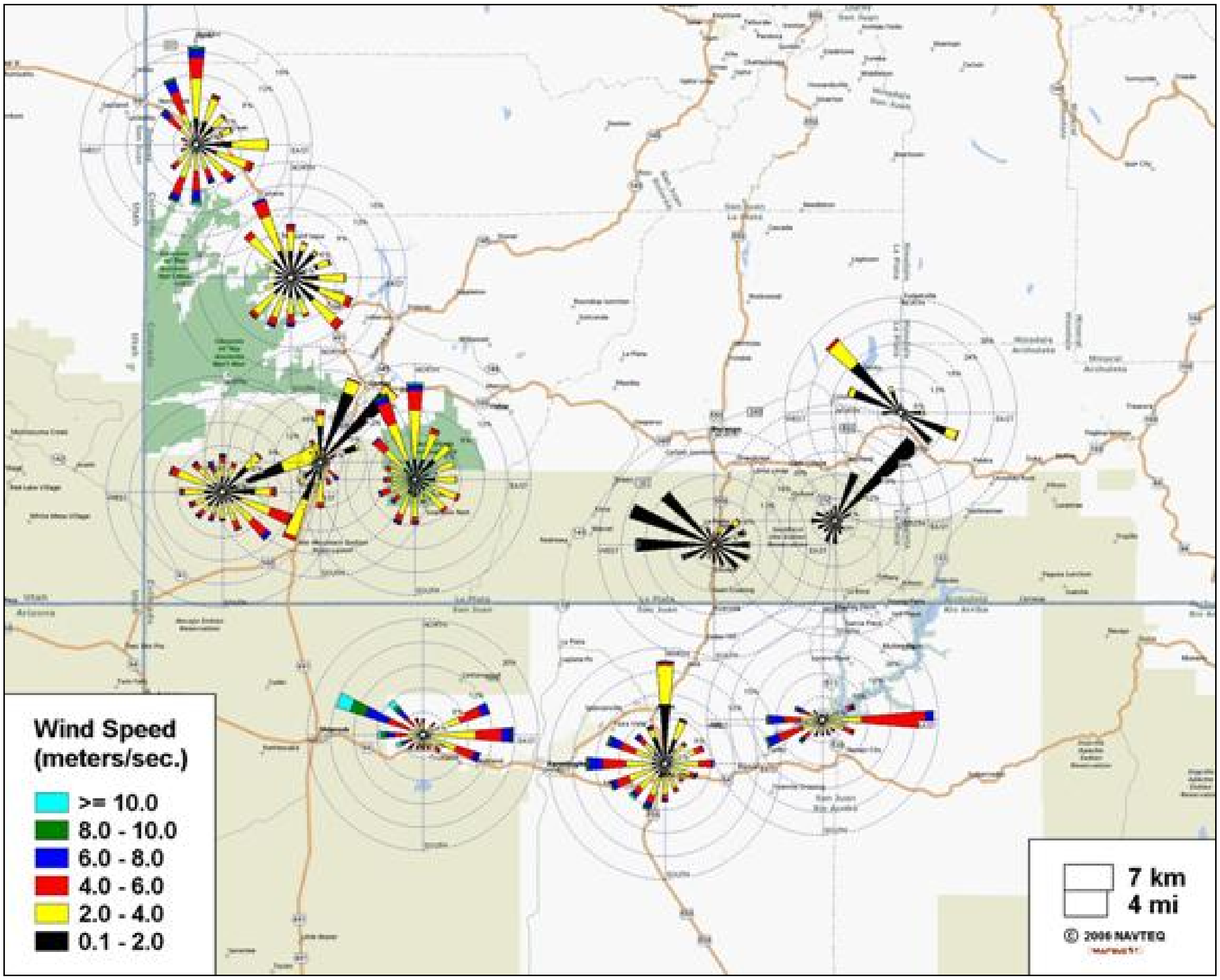
Close-in Four Corners --- Meteorological Sites in 2006



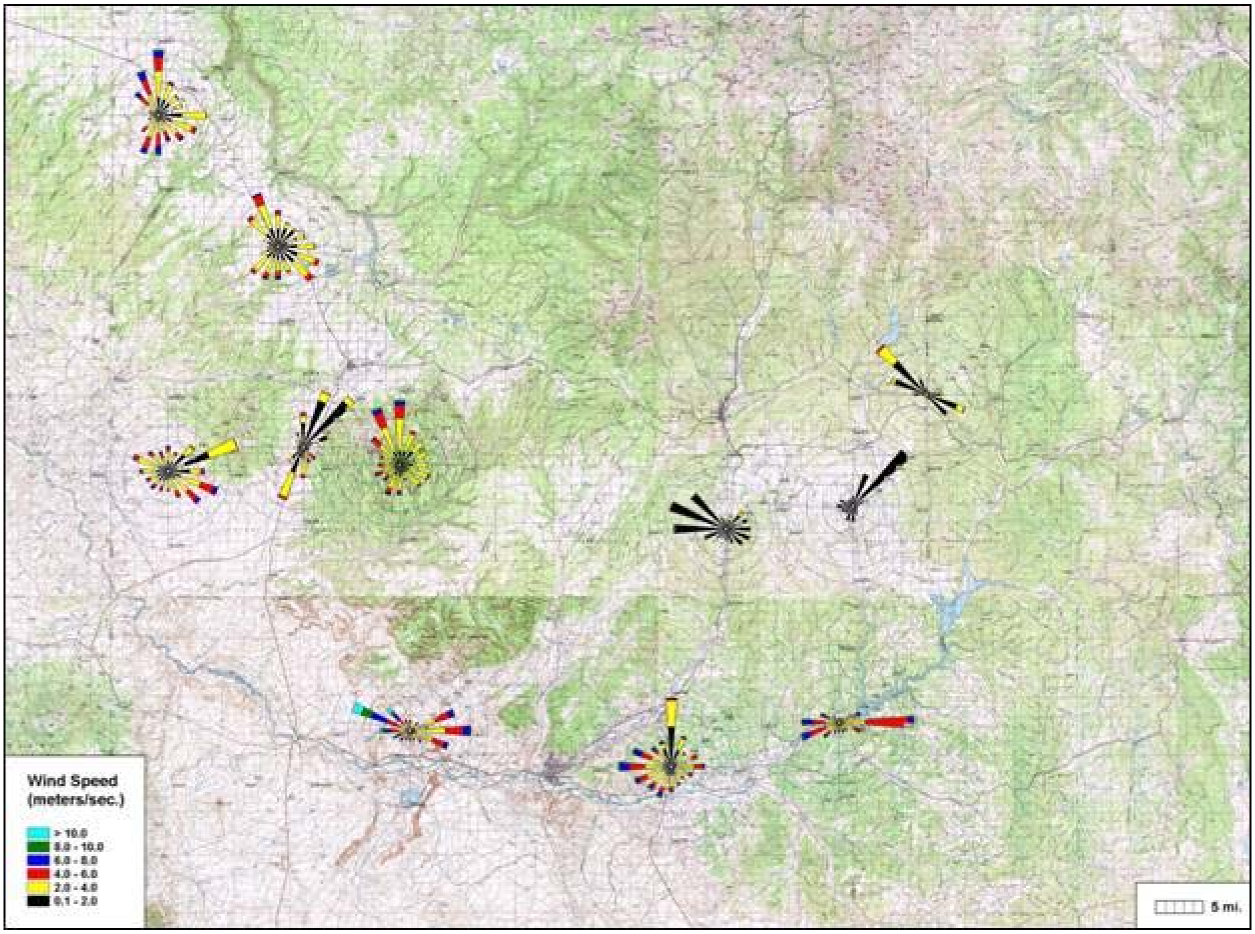
Four Corners --- 2006 Annual Wind Roses



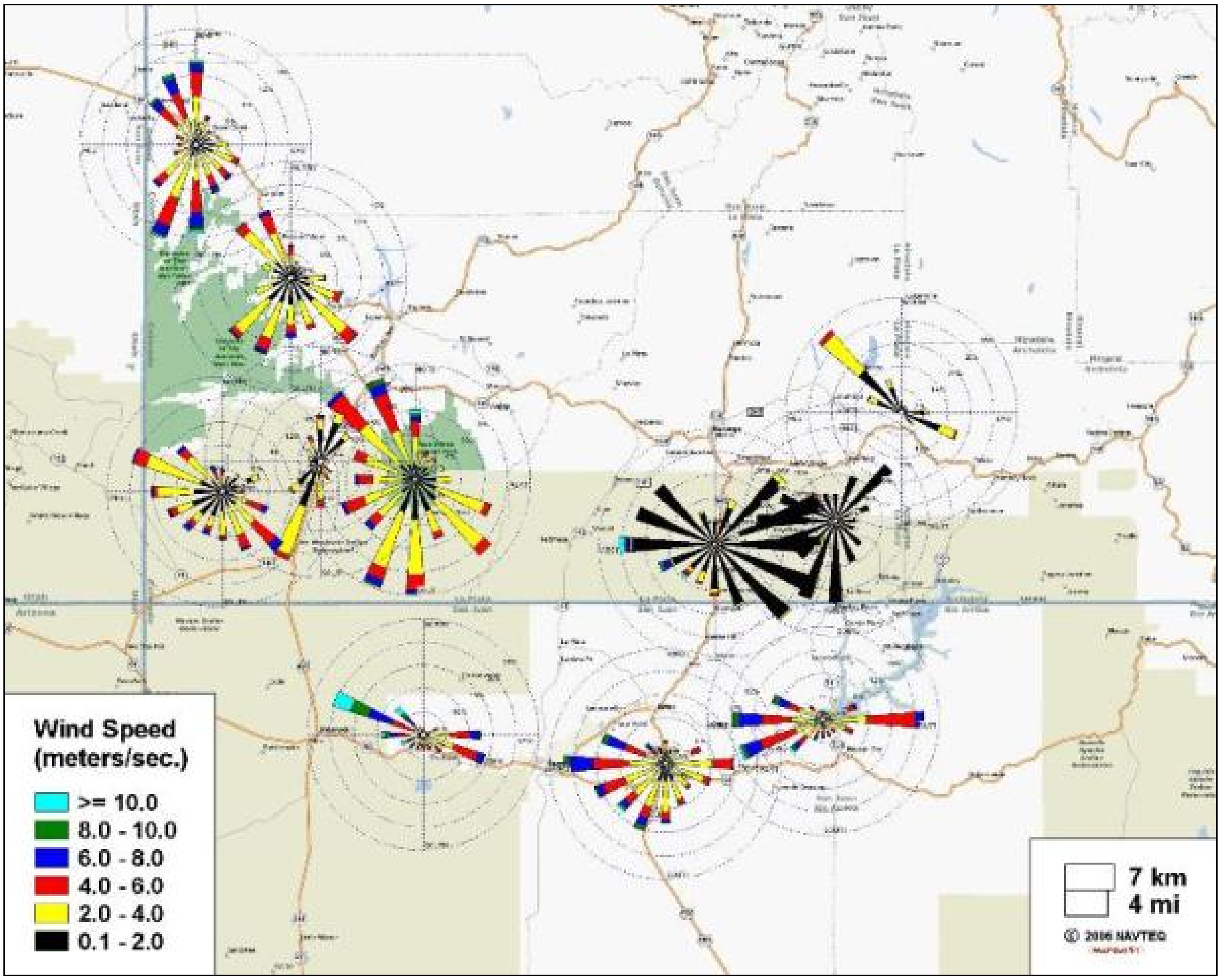
Close-in Four Corners --- 2006 Annual Wind Roses
(Political boundary map)



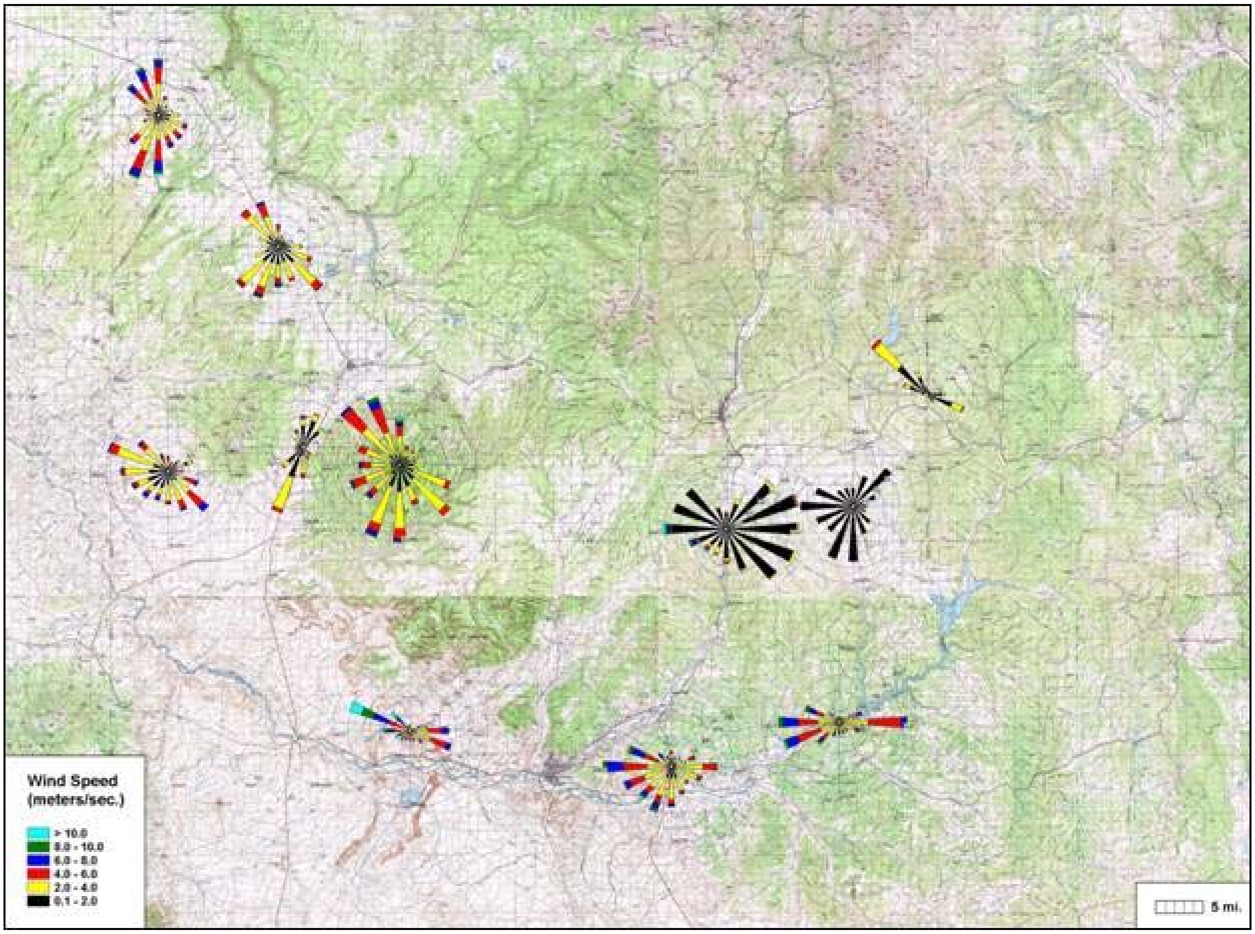
Close-in Four Corners --- 2006 Annual Wind Roses
(Topographic map)



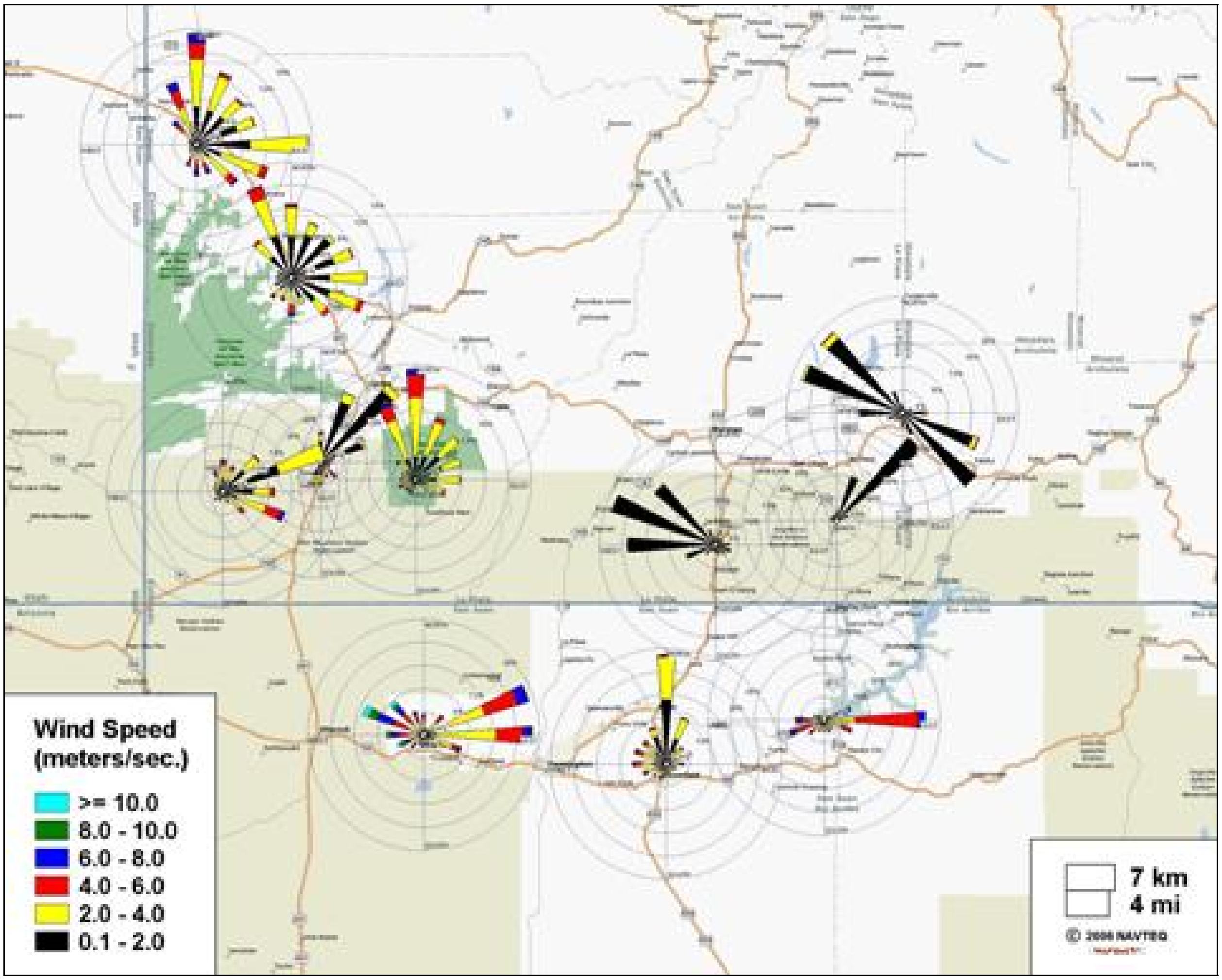
Close-in Four Corners --- 2006 Daytime Wind Roses
(Political boundary map)



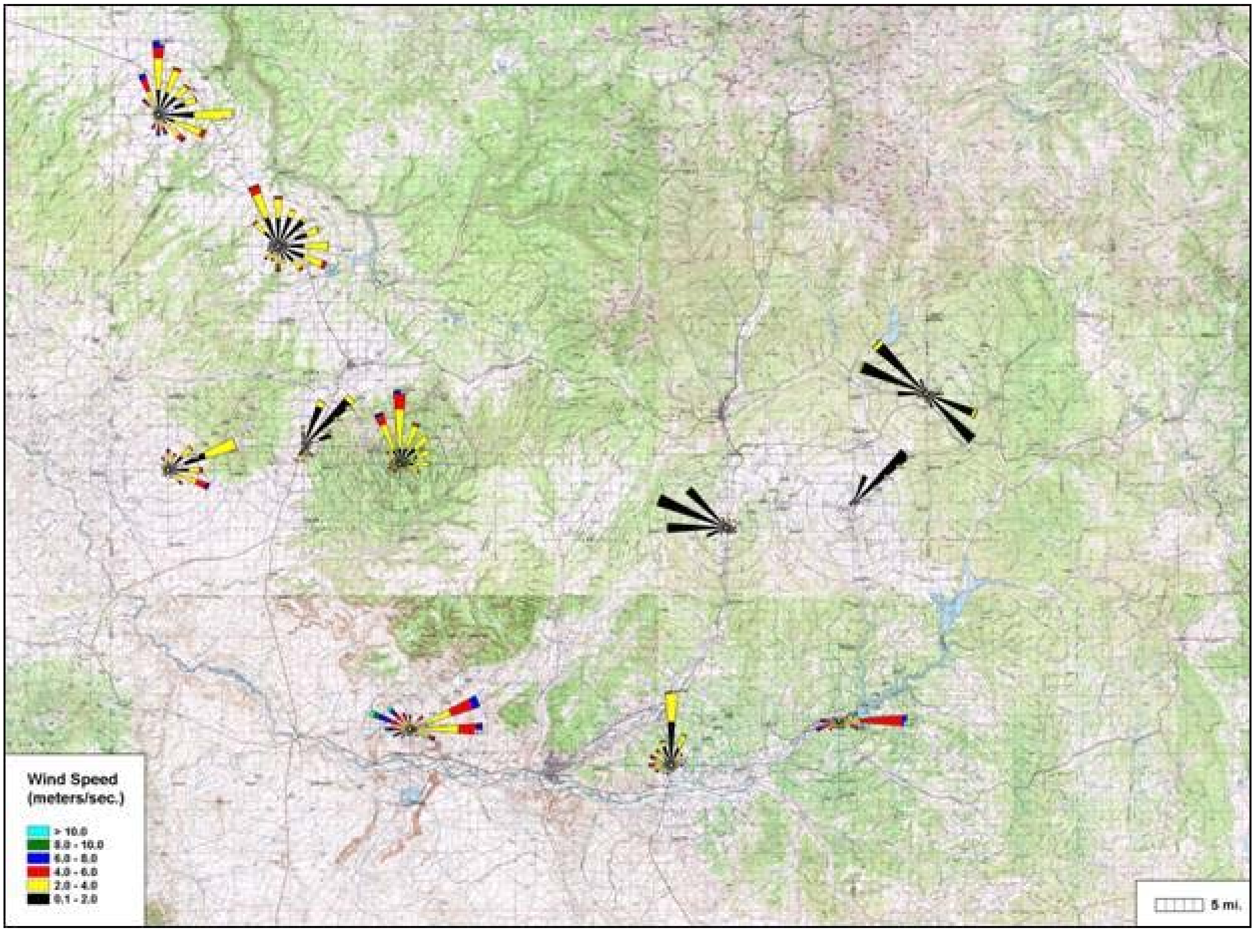
Close-in Four Corners --- 2006 Daytime Wind Roses
(Topographic map)



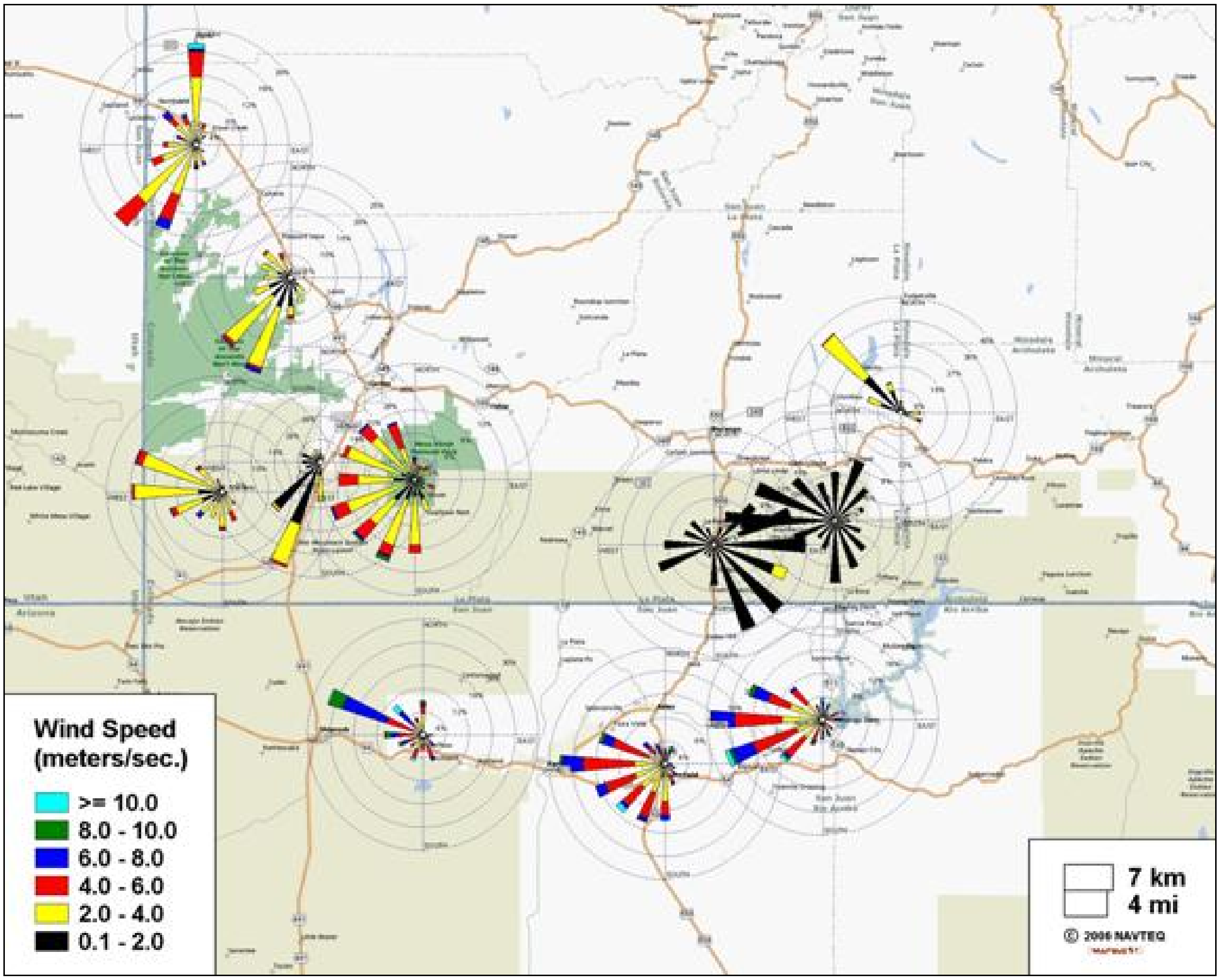
Close-in Four Corners --- 2006 Nighttime Wind Roses
(Political boundary map)



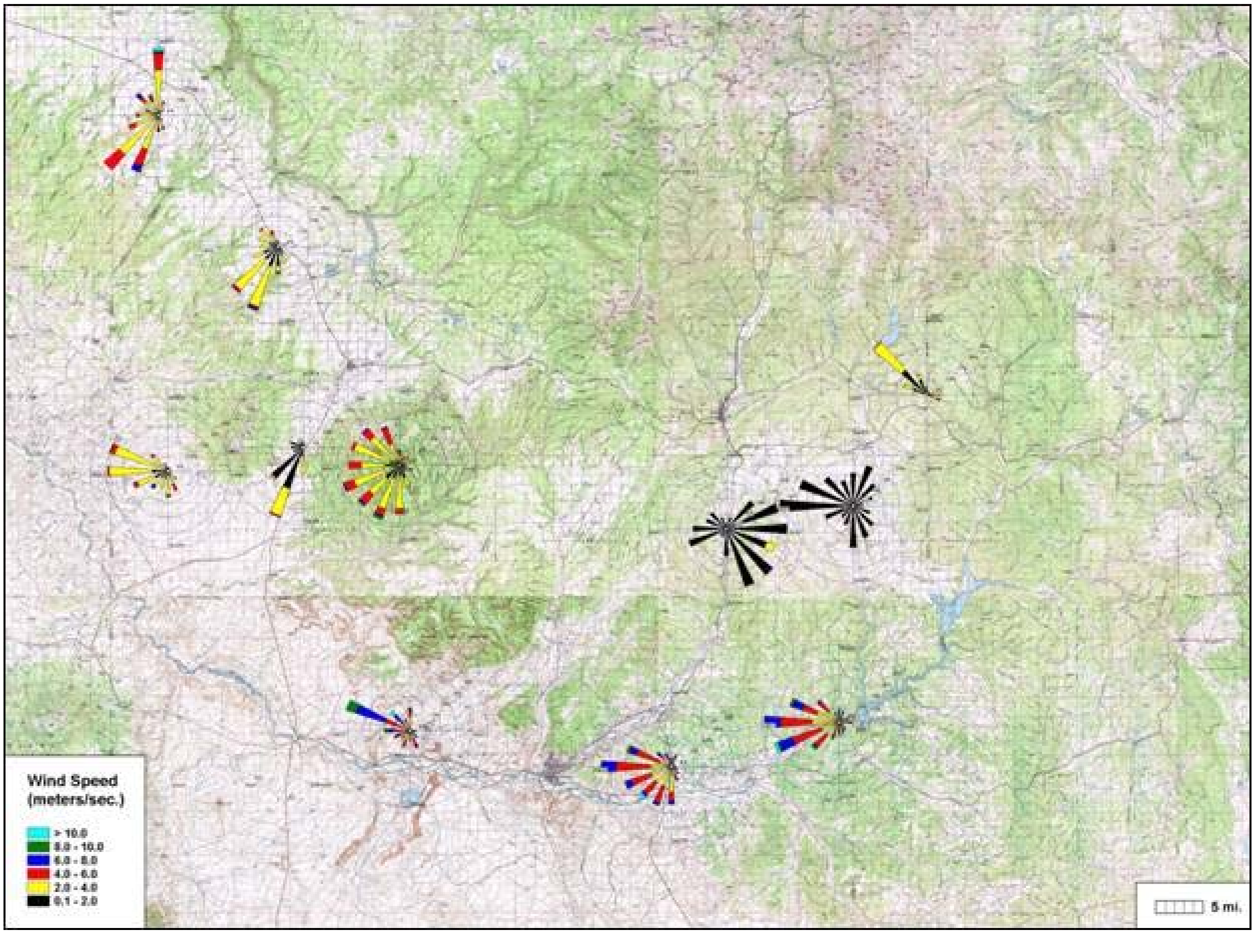
Close-in Four Corners --- 2006 Nighttime Wind Roses
(Topographic map)



Close-in Four Corners --- 2006 Summer Afternoon Wind Roses
(Political boundary map)



Close-in Four Corners --- 2006 Summer Afternoon Wind Roses
(Topographic map)



Ozone and Precursor Gases

Background:

Rationale and Benefits:
Ozone is a colorless, odorless and tasteless gaseous pollutant that is both necessary and harmful to human health. In the stratosphere where it occurs naturally, it provides a barrier to ultraviolet radiation. However, at ground-level in the troposphere, ozone is the prime ingredient of smog. When inhaled, ozone can cause acute respiratory problems, aggravate asthma, cause significant temporary decreases in lung capacity, cause inflammation of lung tissue, impair the body's immune system defenses and lead to hospital admissions and emergency room visits.[1] In addition, ground-level ozone ruptures the cells of green leaves, thereby interfering with the ability of plants to produce and store food, so that growth, reproduction and overall plant health are compromised.

Generally, ozone is a secondary-formation pollutant in the troposphere. That is, ozone is not emitted directly into the air, but is formed from precursor gases called oxides of nitrogen (NOx) and volatile organic compounds (VOCs) that in the presence of heat and sunlight react to form ozone.[1] Thus, ozone is generally an afternoon, summertime issue. Due to the process in which it is formed, however, high ozone levels typically do not occur in the area where the precursor gases are emitted, but may be a few to hundreds of miles away (depending on the meteorology). This means that ozone can be both a regional and a local concern.

VOCs and NOx, the ozone precursor gases, are emitted from both man-made sources (i.e. combustion, oil and gas development, etc.) and natural sources (i.e. plants, forest fires, etc.). VOC's that specifically can lead to ozone formation are generally called non-methane organic compounds (NMOCs) and do not include chlorinated compounds. In general, alkenes, aromatic hydrocarbons and carbonyls have a high ozone formation potential (higher incremental reactivity) while alkanes have a lower potential.[2] NOx primarily consists of nitric oxide (NO) and nitrogen dioxide (NO_2). NO_2, like ozone, is designated as a "criteria" pollutant that has a health-based National Ambient Air Quality Standard (NAAQS).

The NAAQS for ozone is set at a level of 0.08 parts per million for the three-year average of the annual fourth-maximum 8-hour values. However, the Clean Air Scientific Advisory Committee (CASAC) is currently recommending that the standard be reduced to a level in the range of 0.060 to 0.070 parts per million.[3] The NAAQS for NO_2 is set at 0.053 parts per million for an annual average.

Existing ozone data for the Four Corners region:
Ground level ozone is currently monitored on a continuous basis at nine locations in the Four Corners region, with seven sites being in a core area (see ozone sites maps). Two other sites in the region previously monitored for ozone. For regulatory comparisons to the NAAQS, continuous analyzers that have been designated as "equivalent' or "reference" by the U.S. Environmental Protection Agency (EPA) are used. In Colorado, current monitoring is performed at Mesa Verde National Park, two Southern Ute Tribe sites and at the U.S. Forest Service (USFS) Shamrock site near Bayfield. In New Mexico, monitoring is performed at three New Mexico Environment Department (NMED) sites near the San Juan power plant, Bloomfield and Navajo Lake. A Navajo Nation site in Shiprock, NM is planned to commence operation by the end of 2007. The closest site in Arizona is located at Petrified Forest National Park and the closest site in Utah is at Canyonlands National Park. With the exception of the USFS Shamrock site, all of the data are available on EPA's Air Quality System.[4]

Currently, ambient ozone levels in the Four Corners region are below the level of the current NAAQS (see trends and standards graphs). However, at Mesa Verde and one Southern Ute site there is an increasing trend, and the two newer sites (USFS, Navajo Lake) are recording higher levels. Many of the sites would be above the level of a reduced NAAQS, as proposed by CASAC.

In addition, in 2003, EPA conducted a passive ozone monitoring study in the area as part of a Region 6 ozone gap study. Seven passive ozone monitoring sites were established in San Juan County in New Mexico.[5] The data showed significantly high ozone concentrations in the western and northeastern areas of San Juan County, New Mexico, in addition to the high ozone concentrations already found in the north central area of the County.[6]

Pollutant roses were developed to help provide ideas on where ozone precursor sources may come from and where high ozone concentrations may be found. Pollutant roses, like wind roses, are a simple visual way to depict pollutant concentrations as a function of wind direction for a period of time. Pollutant roses are based on the direction that the wind is blowing from. Another way of visualizing a pollutant rose is to picture yourself standing in the center of the plot and facing into the wind. The wind direction is broken down in the 16 cardinal directions (i.e. N, NNE, NE, ENE, E, ESE, SE, SSE, S, etc). The pollutant concentration is broken down into multiple ranges. The length of each arm of the pollutant rose represents the percentage of time the wind was blowing from that direction. The longer the arm, the greater percentage of time the wind is blowing from that direction. Since the occurrence of pollutant concentrations of different ranges from a particular direction are stacked on the radius in order of increasing speeds, one must compare the length of each color to the distance between the percent circles to get the percent of time each range of pollutant concentration occurred. The circles representing the percent of time can vary from rose to rose hence each rose must be checked for the values. Pollutant roses can be generated by a number of commercially available software programs. For this analysis, WRPLOT View from Lakes Environmental Software was employed.[8]

With ozone typically having peak concentrations in the summer afternoons when sunlight is strongest, pollutant roses were developed accordingly and were placed on both political boundary and topographic base maps (see pollutant rose maps). As can be seen from these pollutant rose maps, ozone at the three southern core area sites in New Mexico and the Mesa Verde site in Colorado show predominantly westerly wind directions in this summer afternoon timeframe. This generally mirrors the predominant San Juan River drainage. The two Southern Ute Tribe sites and the Forest Service Shamrock site appear to be heavily influenced by local topography. Thus, based on these pollutant roses, it is likely that ozone concentrations could also be high further to the east and north of the New Mexico Navajo Lake site, further up the San Juan River and Piedra River drainages. While no monitoring exists to confirm or deny, winds could also flow up other drainages in summer afternoons, including the Dolores and Animas Rivers.

For ozone precursor gases, NOx monitoring currently exists at six sites in the Four Corners region (see NO_2 sites map), including two Southern Ute tribe sites and the USFS Shamrock site in Colorado, and three NMED sites. A Navajo Nation site in Shiprock, NM is scheduled to commence operation. Two other sites previously had NOx monitoring. NO_2 levels have been fairly steady over the years at most sites, at a level well below the NAAQS (see NO_2 trends graphs). At two sites in particular, San Juan Substation, NM and Bloomfield, NM, the NO_2 levels do appear to be increasing over time. NO, unfortunately, has not been reported consistently as it is not designated a criteria pollutant. However, NO levels do appear to be increasing at both Southern Ute Tribe sites, Ignacio and Bondad (see NO trends graphs). These increases in NO and NO_2 are of concern due to the potential for increased ozone formation and also indicates that there are increased combustion sources in the area, possibly due to oil and gas development and increased traffic. VOC baseline monitoring for San Juan County, New Mexico was conducted in 2004 and 2005 at three sites. One site was near Bloomfield, NM near some industrial sources, a second near the San Juan power plant and the third site was near Navajo Lake, in an oil and gas development area. Results showed that alkane concentrations dominated, especially ethane and propane. The biogenic compound isoprene and the highly reactive VOC compounds, ethylene and propylene, were not present in significant quantities.[6,7]

<u>Data Gaps:</u>
While it would appear that there is a sufficient ozone monitoring network in the Four Corners region, some areas are lacking. Pollutant roses were developed to determine the directions from which ozone precursors are most likely to be transported by wind (see ozone pollutant roses). In general, for summer afternoon periods when ozone levels are expected to be highest, winds are generally from the west to southwest. Oil and gas development increased significantly after many of the current sites were installed. This development has provided a significant increase in both VOC and NOx precursor gas sources to the region. Ozone monitoring currently exists in the major oil and gas development areas, but little downwind ozone monitoring currently exists.

VOCs are also a gap, as the short-term studies in 2004 and 2005 were located toward the southern edge of the oil and gas development area, or not in the development area at all. While emissions inventories can provide an estimate of total VOCs that may be released to the atmosphere, these are primarily based on predicted emissions, not on actual measurements. This is a concern as different VOCs have different ozone formation potentials and the oil and gas development has dramatically increased in the region since these studies.

Suggestions for Future Monitoring Work:

C. Install and operate two or three long-term continuous monitoring stations for ozone. One station would be located upstream of Navajo Lake, in the San Juan River drainage toward Pagosa Springs, CO, or in the Piedra River drainage, toward Chimney Rock, CO. This area is toward the northeastern portion of the Four Corners region and is downwind of many VOC precursor gas sources from oil and gas development. The second station would be located to the north of Cortez. This area is in the north-central portion of the Four Corners region and is downwind of both an urban area and any precursor gas emissions that would funnel up between Sleeping Ute Mountain and Mesa Verde. If funding exists, a third site in Arizona on Navajo Nation land, in the southwest portion of the Four Corners area, is recommended. This site, possibly at Canyon de Chelly National Monument, would be to the west of a high ozone area as determined in the 2003 passive ozone study and would provide a good representation of regional ozone levels entering the Four Corners area. Each site, including shelter and instrumentation, would cost approximately $15,000 to $20,000 (total = $45,000 to $60,000). Annual operating costs (not including field personnel) would be approximately $1,500 per site (total = $3,000).

D. Perform an ozone saturation study using passive samplers across the entire Four Corners region to determine areas of highest ozone concentration. This would help determine if existing or new continuous monitoring sites are located in appropriate areas or if continuous ozone monitors need to be added or moved. It is expected that at least 20 passive ozone sites over the four-state region would be needed. Running for 30 days during a summer, the approximate cost would be $22,000 (not including field personnel time).

   (Note: In early July 2007, the Colorado legislature appropriated funding for passive ozone monitoring in Colorado. As a result, a short-term study was performed in three areas of Colorado at 50 locations. These areas included the north Front Range, central western and southwestern/Four Corners. For the southwestern area, 12 passive ozone sampling sites were operated from early August to early September 2007. While not a definitive study, funding is expected to be available in future years to perform more refined passive ozone monitoring.)

E. Perform monitoring for VOCs (in particular NMOCs) and carbonyls in the oil and gas development areas to determine the actual constituents in the emissions from wellheads, leaks and tanks. This would help in determining the potential for ozone formation from these compounds. This suggestion also includes follow-up monitoring for VOCs, both in and near the oil and gas development area, to compare to the 2004 and 2005 baseline data from San Juan County, New Mexico. A minimum of four to five sites is recommended; two sites in the oil and gas development area, one background site and one or two follow-up sites. For a year of monitoring, every sixth day, the approximate cost (not including field personnel time) would be $45,000 per site (total = $180,000 to $225,000).

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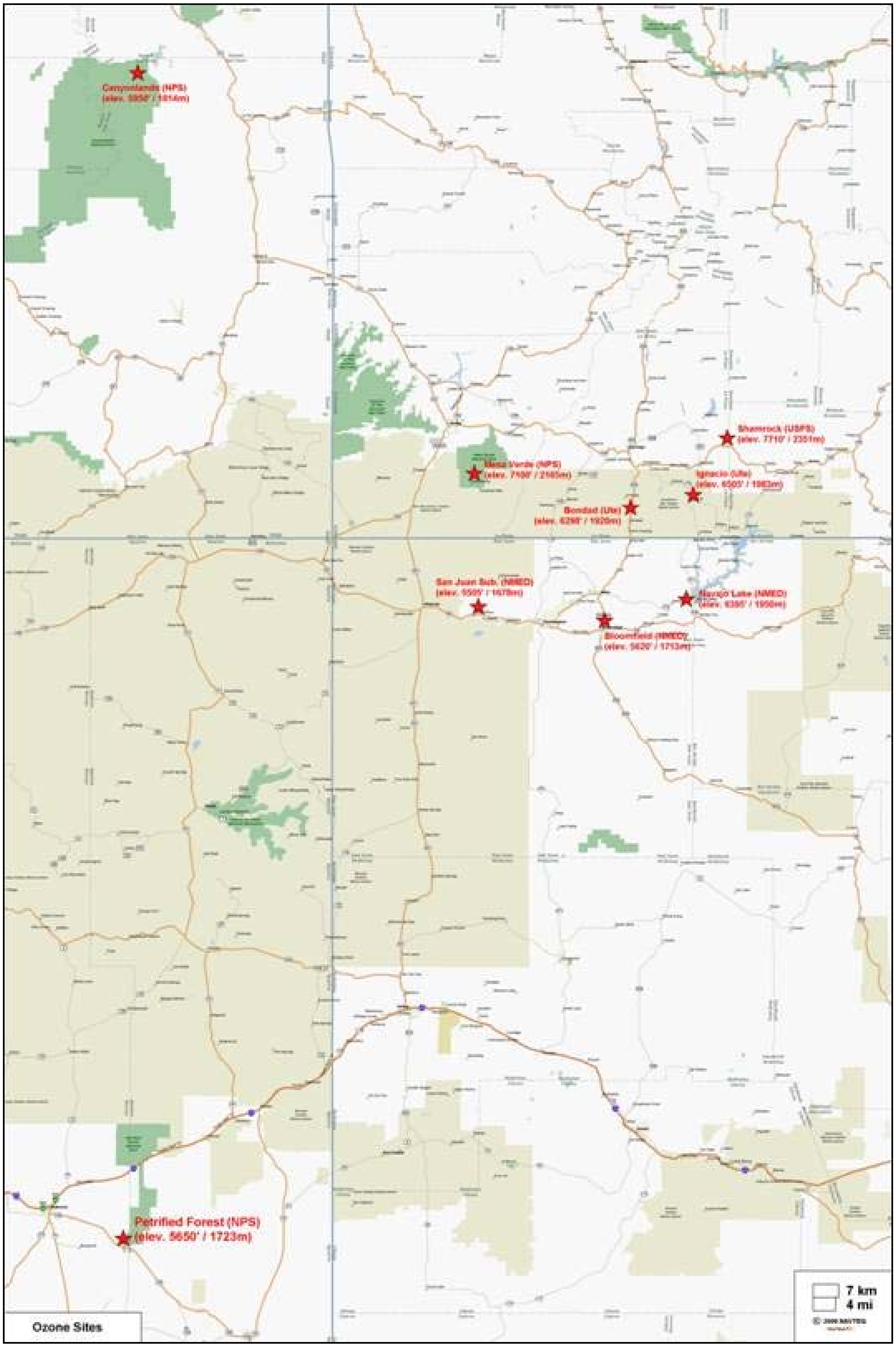
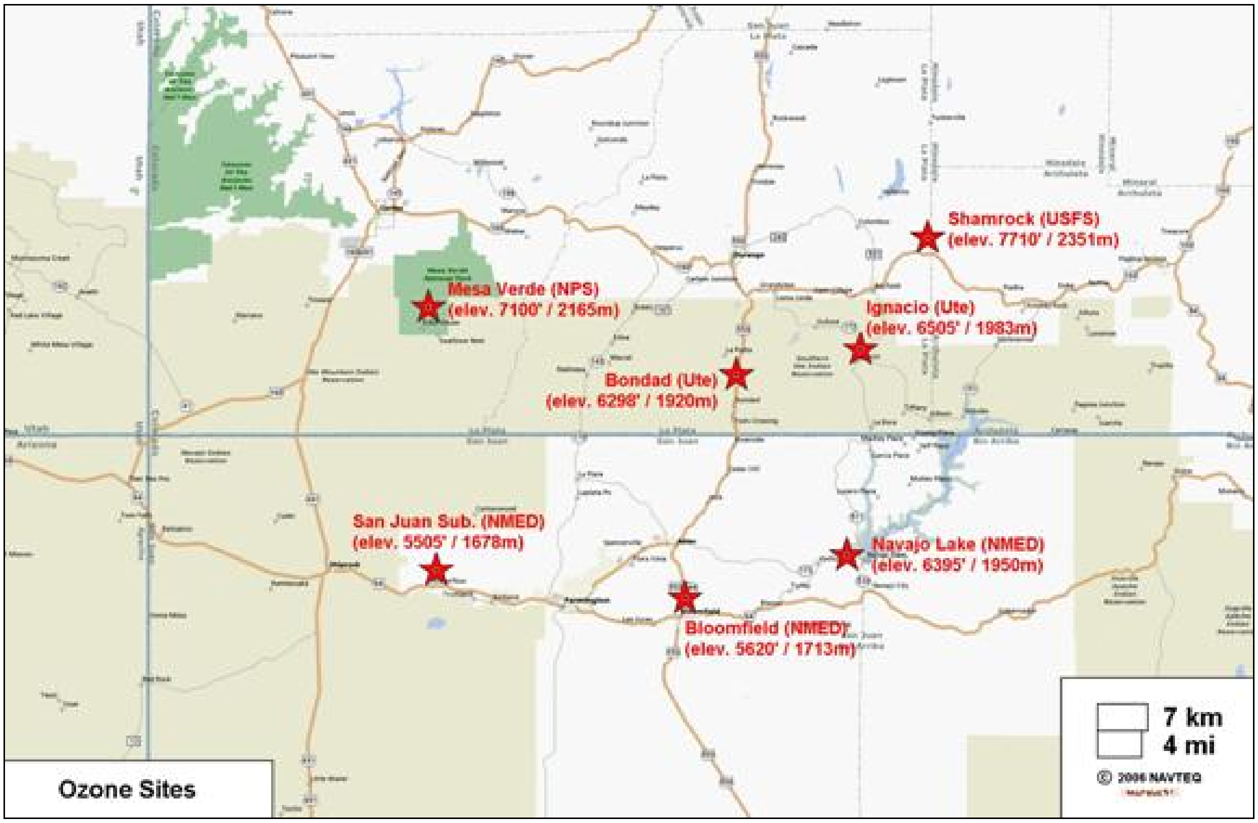
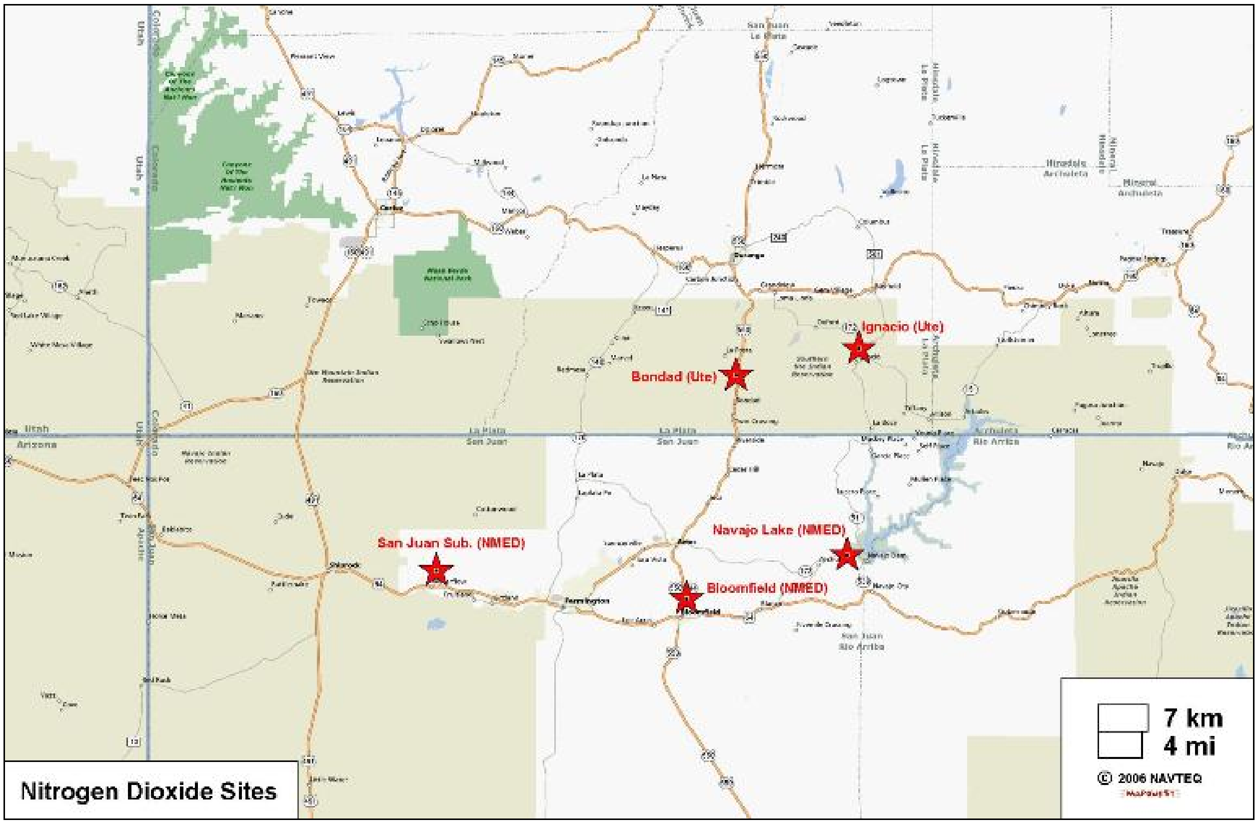
Four Corners --- Continuous Ozone Sites in 2006



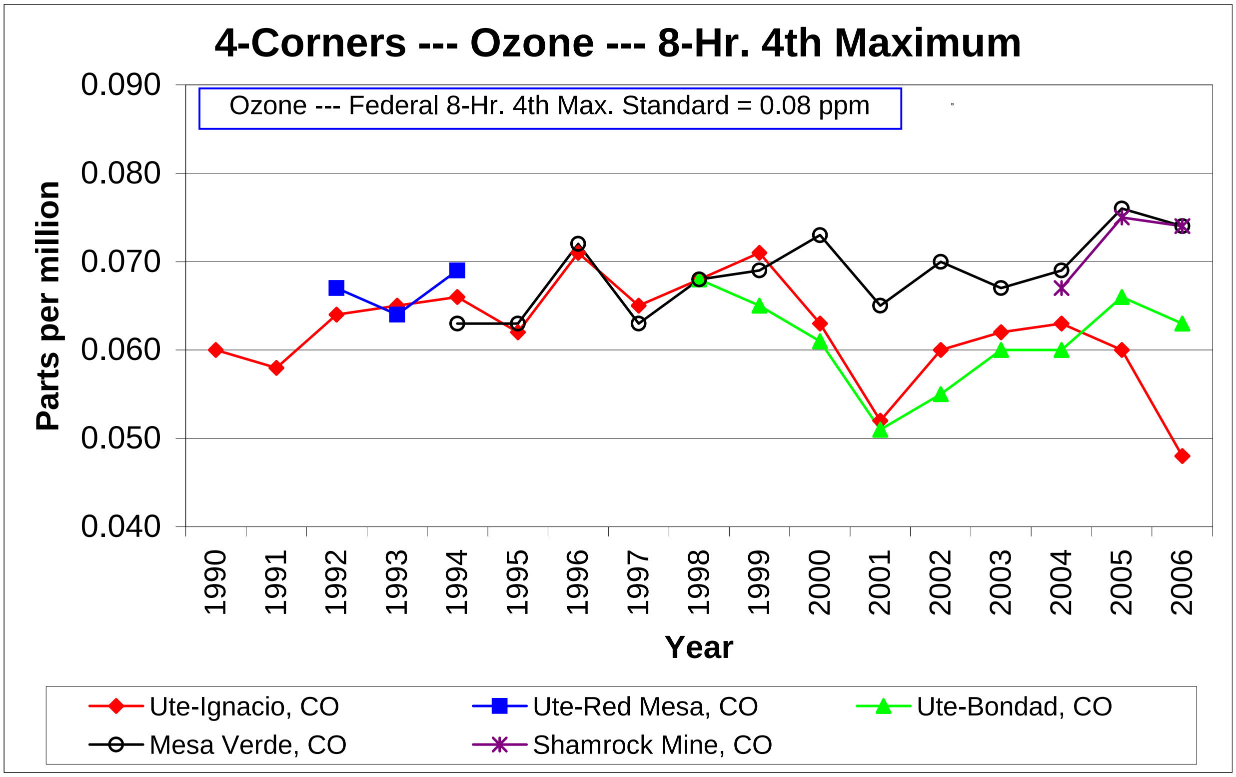
Close-in Four Corners --- Continuous Ozone Sites in 2006

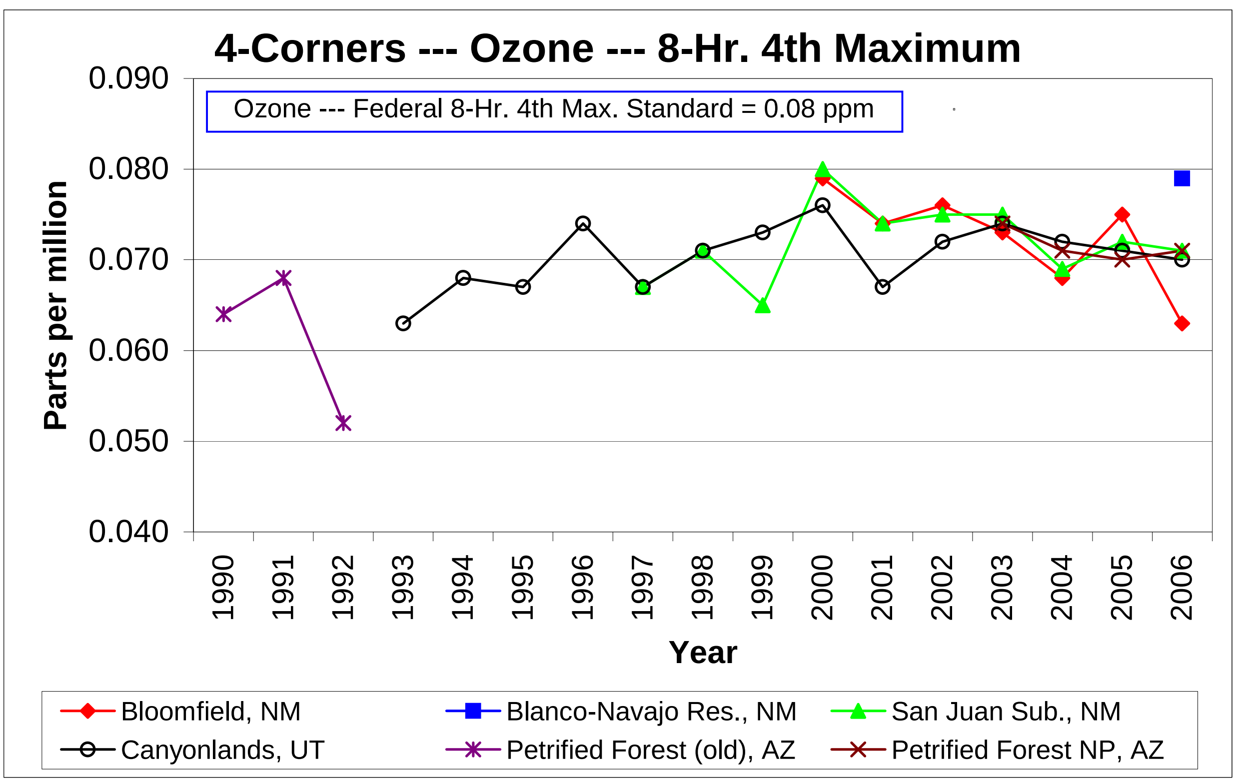


Four Corners --- Continuous Nitrogen Dioxide Sites in 2006

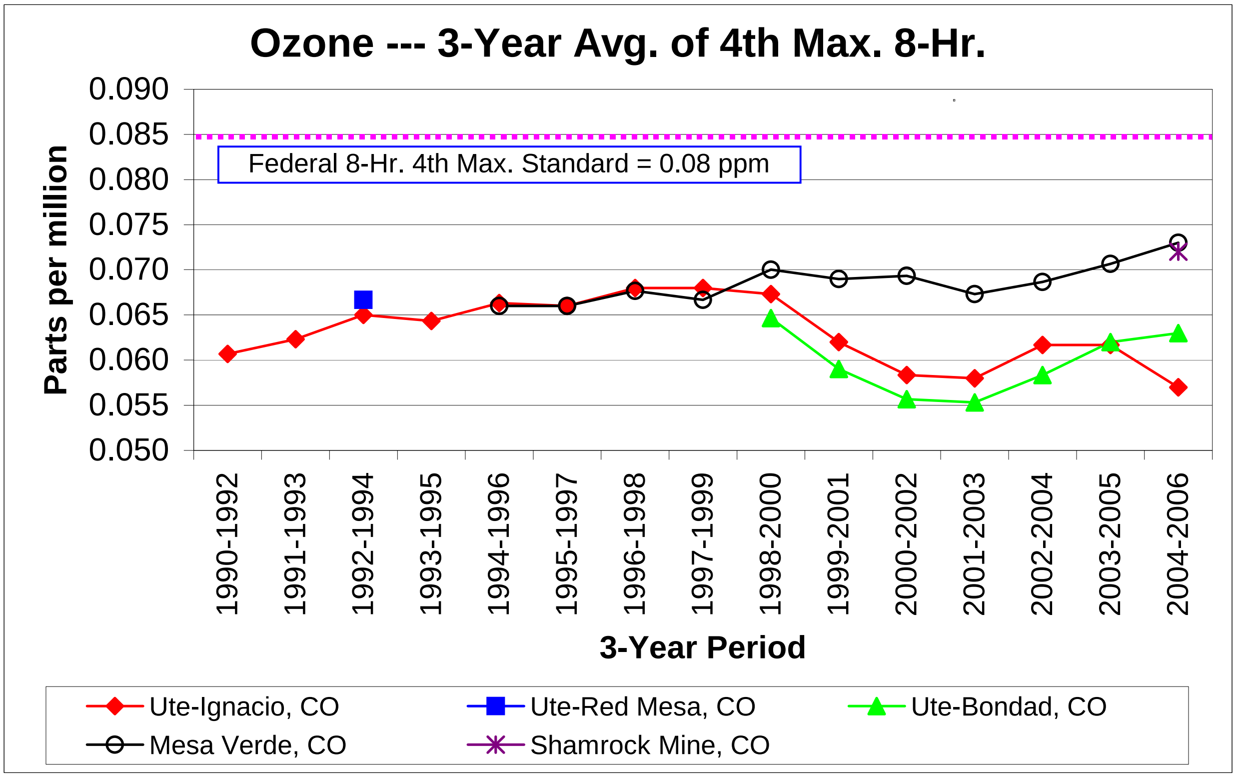


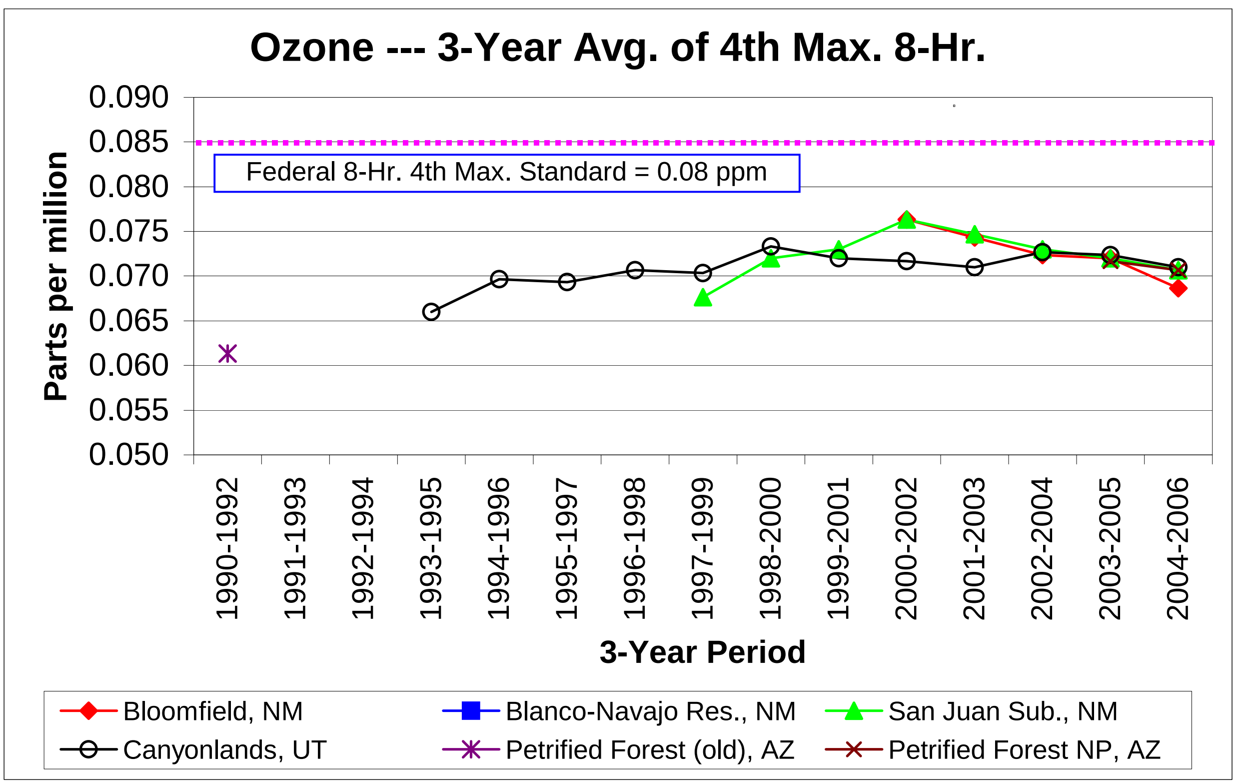
Four Corners --- Ozone Trends (4th Maximum 8-Hour)



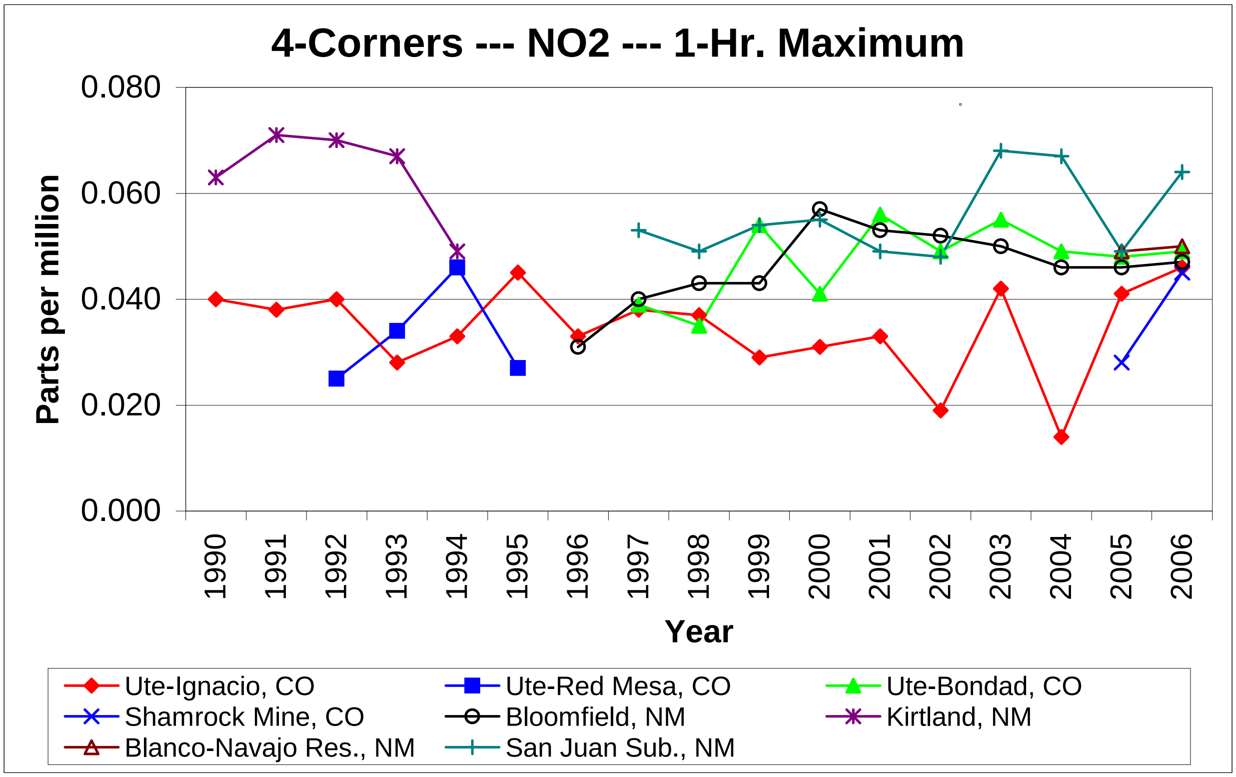


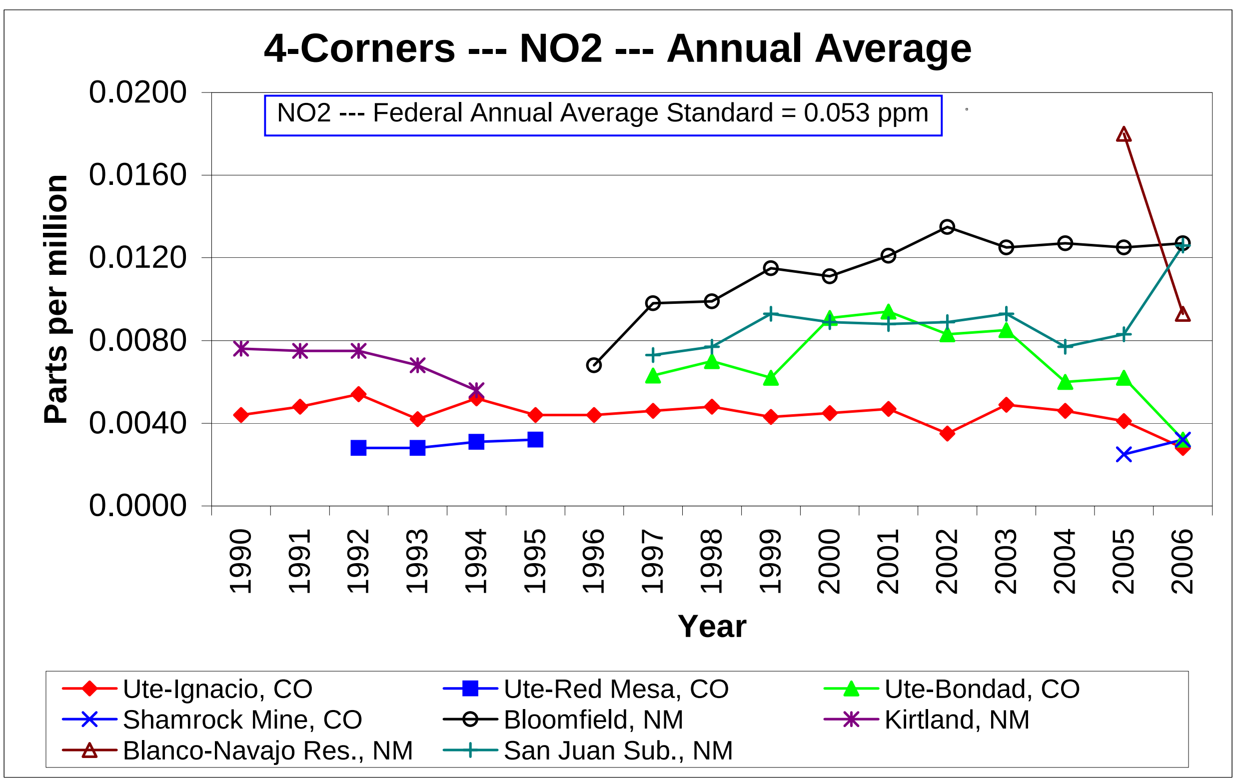
Four Corners --- Ozone Standard (3-Year Avg. of 4th Max. 8-Hour)



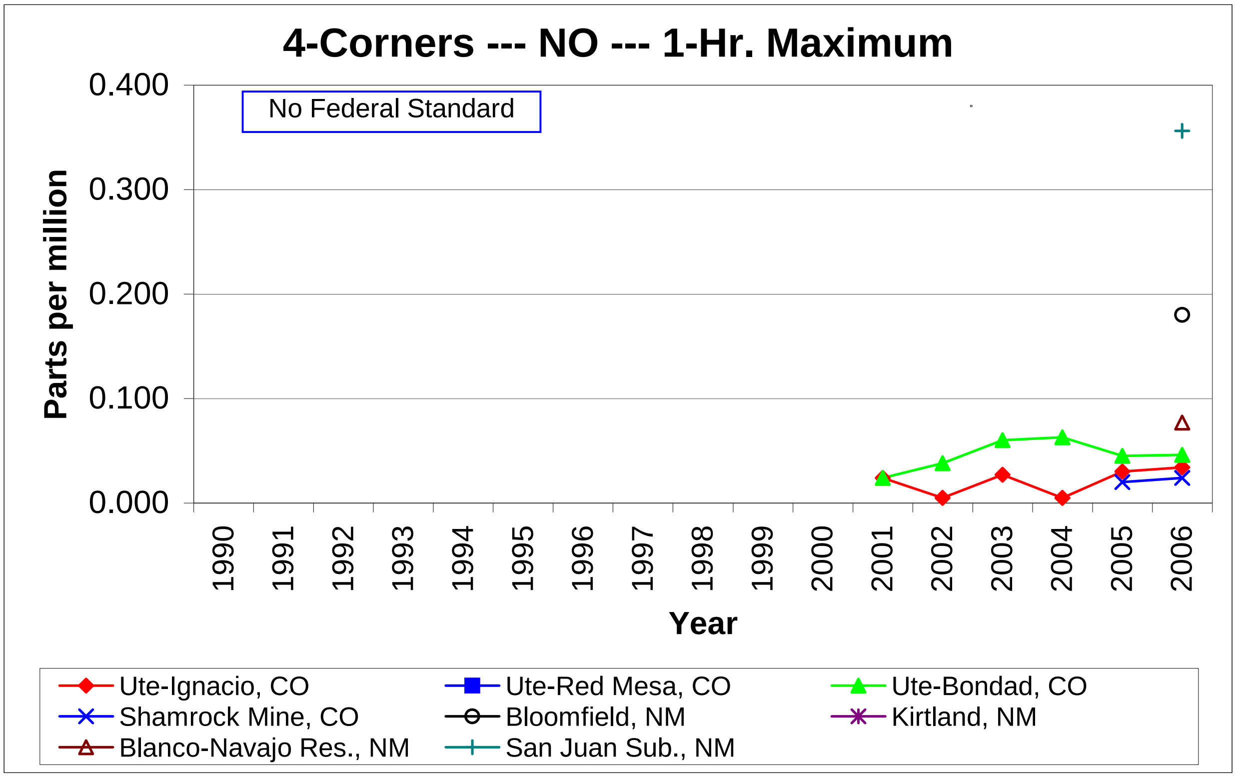


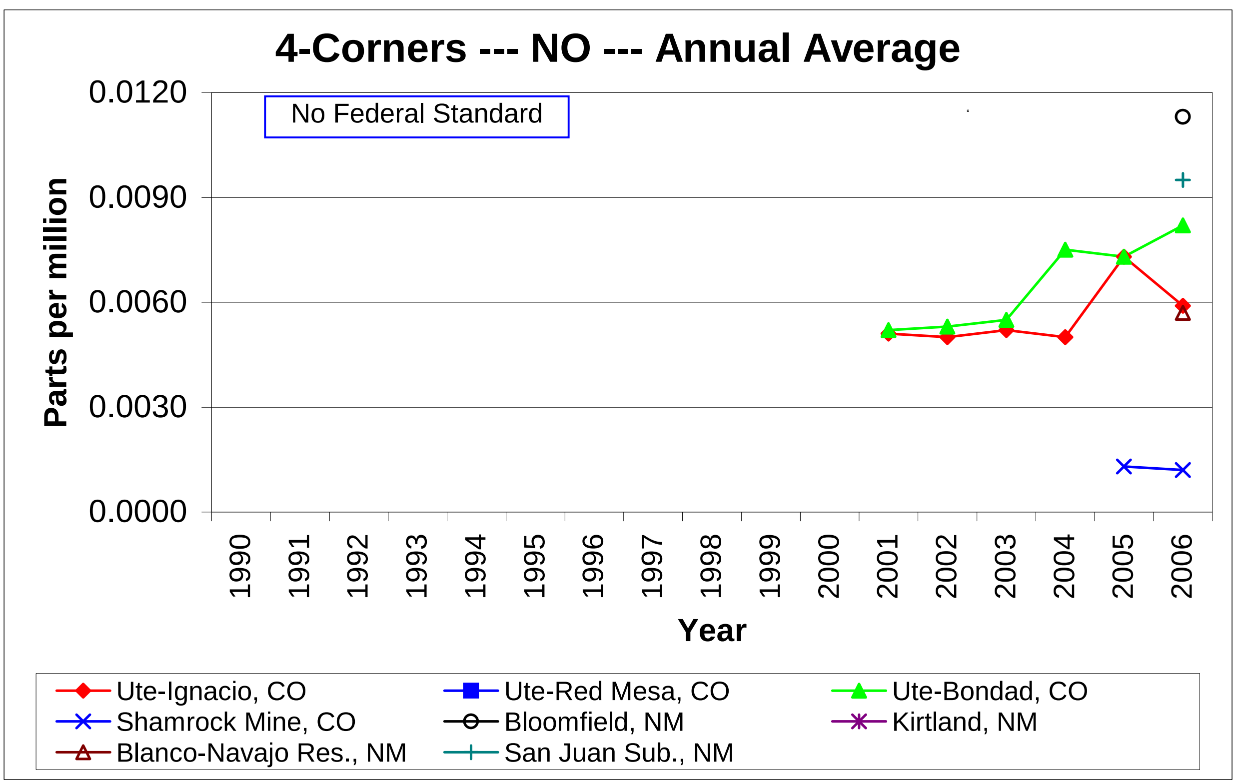
Four Corners --- Nitrogen Dioxide Trends



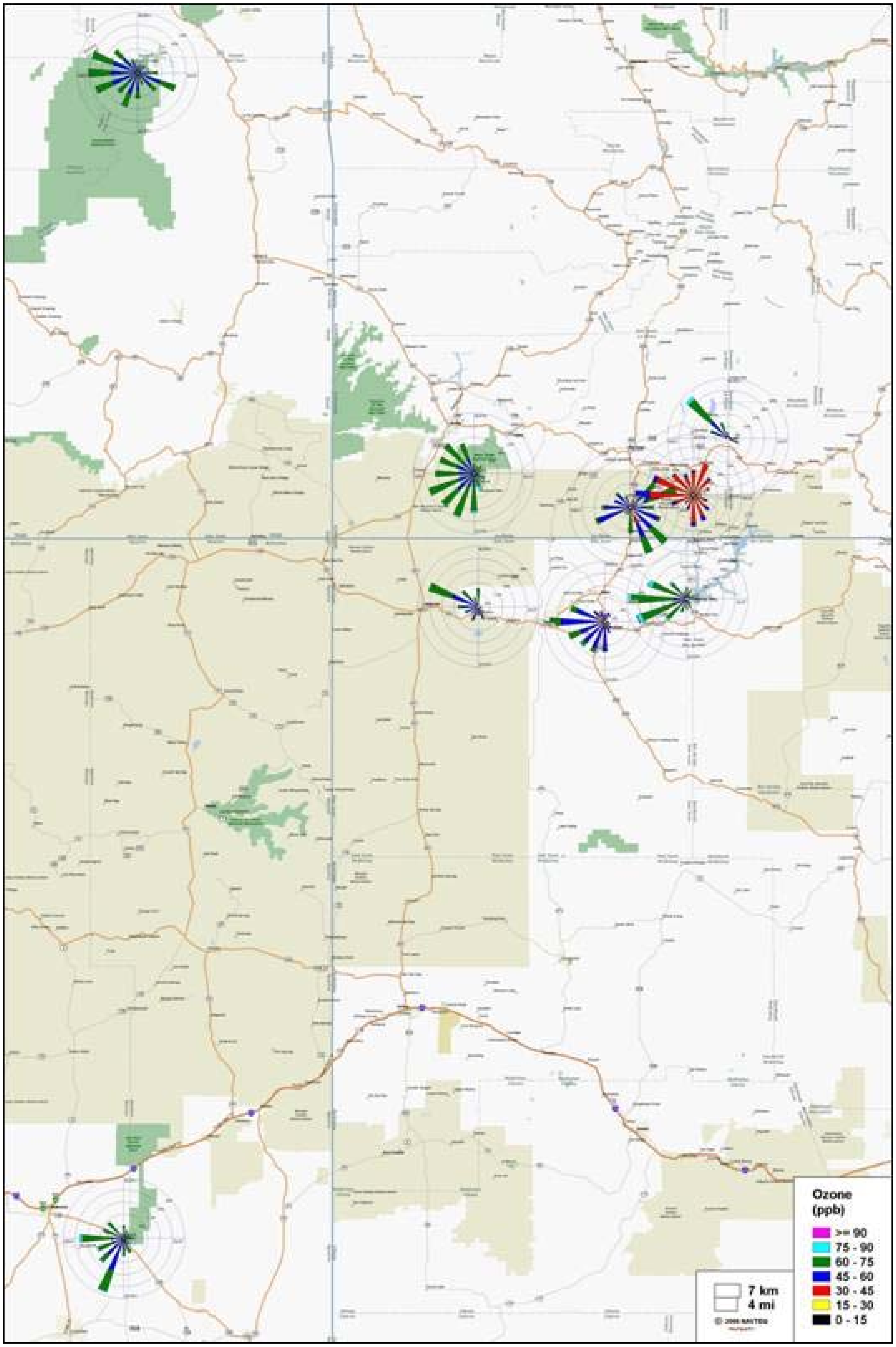


Four Corners --- Nitric Oxide Trends

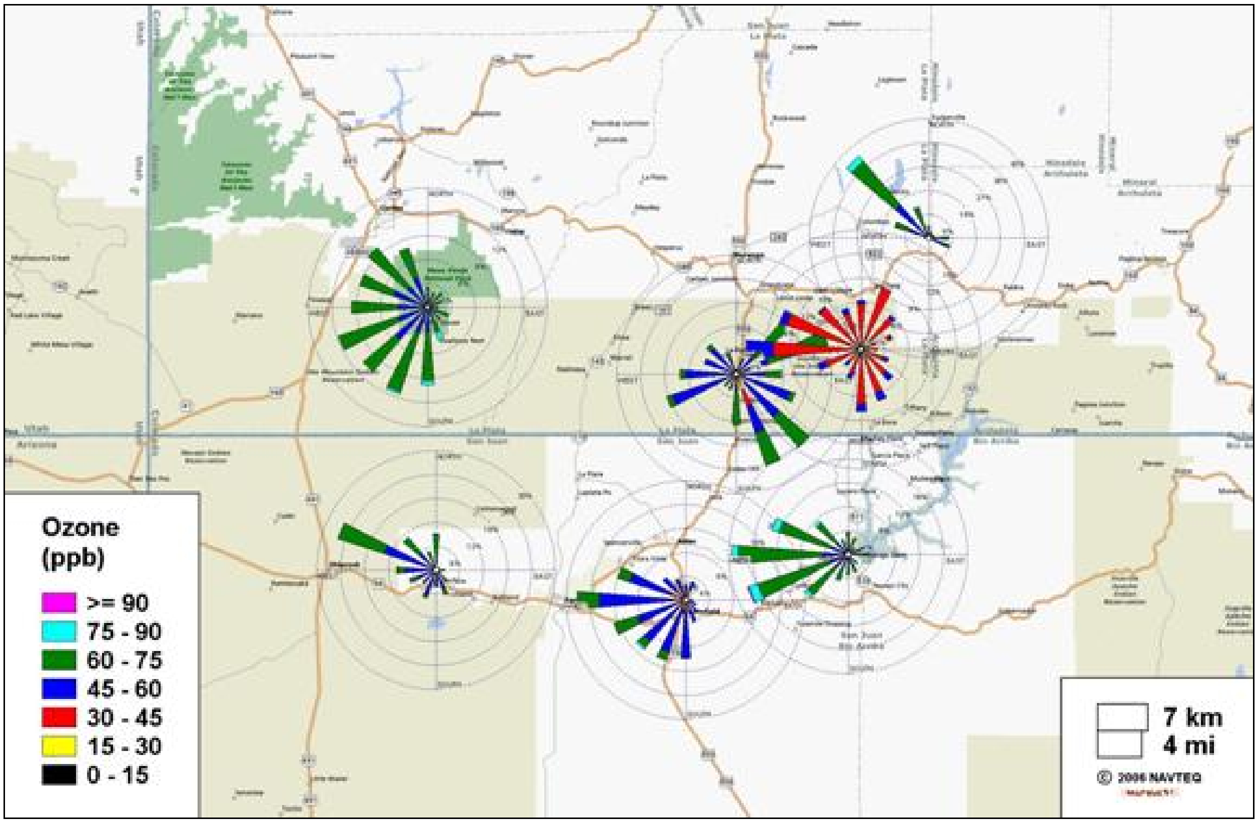




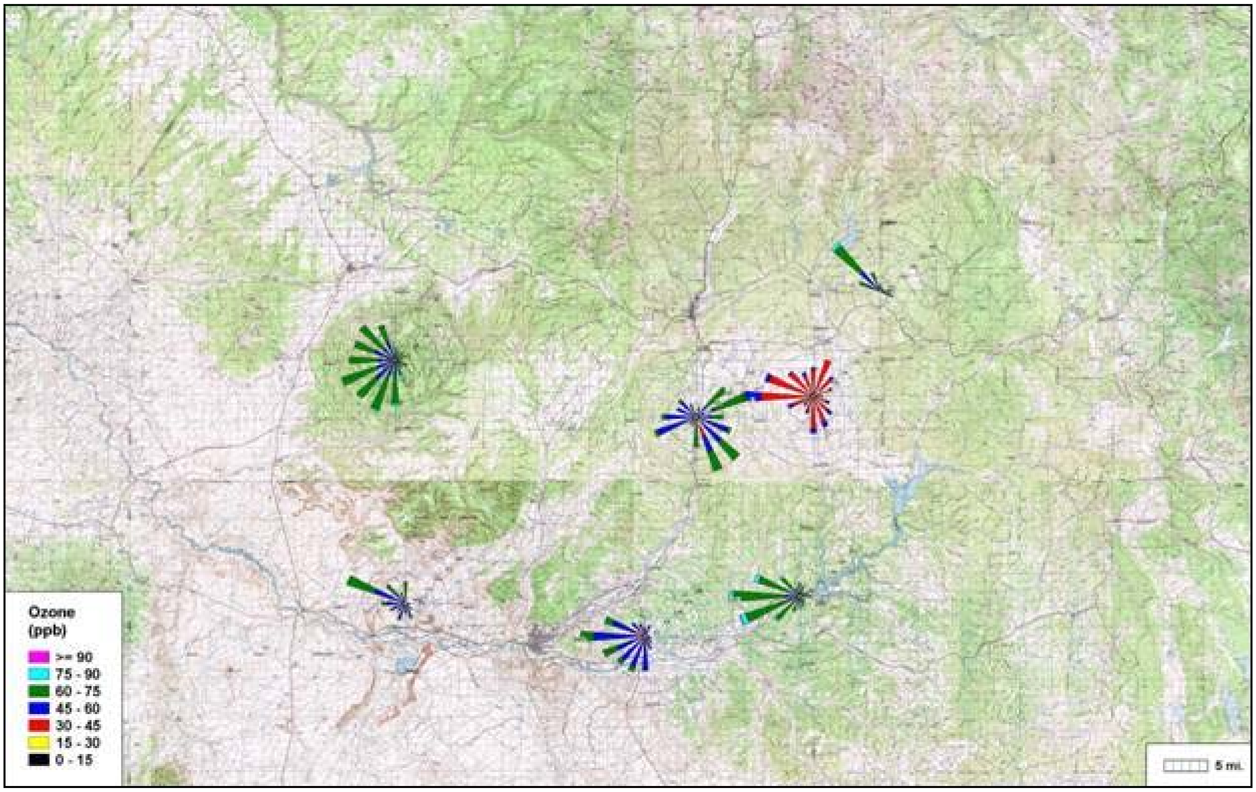
Overall Four Corners --- Summer Afternoon Ozone Pollution Roses (2006)



Close-in Four Corners --- Summer Afternoon Ozone Pollution Roses (2006)
(Political boundary map)



Close-in Four Corners --- Summer Afternoon Ozone Pollution Roses (2006) (Topographic map)



Carbon Monoxide, Particulates and Other Common Pollutants

Background:

Rationale and Benefits**:**
Carbon monoxide, or CO, is a colorless, odorless gas that is formed when carbon in fuel is not burned completely. It is a component of motor vehicle exhaust, which contributes about 56 percent of all CO emissions nationwide. Other non-road engines and vehicles (such as construction equipment and boats) contribute about 22 percent of all CO emissions nationwide. Higher levels of CO generally occur in areas with heavy traffic congestion. In cities, 85 to 95 percent of all CO emissions may come from motor vehicle exhaust. Other sources of CO emissions include industrial processes (such as metals processing and chemical manufacturing), residential wood burning, and natural sources such as forest fires. Woodstoves, gas stoves, cigarette smoke, and unvented gas and kerosene space heaters are sources of CO indoors. The highest levels of CO in the outside air typically occur during the colder months of the year when inversion conditions are more frequent.[1]

Carbon monoxide can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain) and tissues. This results in cardiovascular and/or central nervous system effects, such as chest pains, vision problems and reduced ability to work or exercise.[1] The health-based National Ambient Air Quality Standard (NAAQS) for carbon monoxide is set at a level of 35 parts per million for a one-hour average and 9 parts per million for an eight-hour average.[2]

Particulates are broken into two categories for NAAQS: PM_{10}, which is particulate matter that is 10-microns in diameter and smaller, and $PM_{2.5}$, which is particulate matter 2.5 microns in diameter and smaller. Thus, $PM_{2.5}$ is a subset of PM_{10}. Particulates are an inhalable mixture of solid particles and liquid droplets found in the air. Some particles, such as dust, dirt, soot, or smoke, are large or dark enough to be seen with the naked eye. Others are so small, they can only be detected using an electron microscope. These particles come in many sizes and shapes and can be made up of hundreds of different chemicals. Some particles, known as *primary particles* are emitted directly from a source, such as construction sites, unpaved roads, fields, smokestacks or fires. Others form in complicated reactions in the atmosphere of chemicals such as sulfur dioxides and nitrogen oxides that are emitted from power plants, industries and automobiles. These particles, known as *secondary particles*, make up most of the fine particle pollution in the country.[3]

Particle pollution, especially fine particles, contains microscopic solids or liquid droplets that are so small that they can get deep into the lungs and cause serious health problems. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including increased respiratory symptoms (such as irritation of the airways, coughing, or difficulty breathing), decreased lung function, aggravated asthma, development of chronic bronchitis, irregular heartbeat, nonfatal heart attacks and premature death in people with heart or lung disease.[3] The health-based NAAQS for PM10 is set at a level of 150 micrograms per cubic meter for a 24-hour average. For PM2.5, the health-based NAAQS are set at levels of 35 micrograms per cubic meter for a 24-hour average and 15 micrograms per cubic meter for an annual average.[2]

Other common pollutants in the ambient air that are not covered in other option papers may include lead, carbon dioxide, organic compounds/hazardous air pollutants (HAPs), pesticides, and others. Of these, only lead has a health-based NAAQS, which is 1.5 micrograms per cubic meter for a calendar quarter average.[2]

Lead is primarily emitted from metals processing or waste incinerator sources. Historically, leaded automobile fuels were the primary source.[4] Lead is typically associated with neurological impairment. Carbon dioxide is emitted from a variety of natural and human-related sources. With implications as a greenhouse gas rather than health concerns, the largest man-made source of carbon dioxide, by far, is fossil fuel combustion.[5] Organic compounds can be both toxic and non-toxic in nature. Toxic air pollutants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. These compounds can come from a variety of sources, though primarily from industrial or mobile (i.e. motor vehicle) source. Thus, they are typically associated with urban areas.[6] The U.S. Environmental Protection Agency currently lists 188 HAPs for which it would like to reduce atmospheric releases/emissions. While no ambient standards currently exist for these pollutants, workplace standards do exist for some of them. Pesticides are substances or mixture of substances intended for preventing, destroying, repelling, or mitigating any pest.[7] While all regulated pesticides have been tested for health impacts to humans, exposures can and do occur from improper use.

Existing data for the Four Corners region:
Carbon monoxide in the ambient air is currently monitored on a continuous basis at only one site in the Four Corners region. This is at the Southern Ute Tribe's Ignacio site in southern Colorado. Monitoring was performed at New Mexico's Farmington site, but was discontinued in 2000. (See the CO site locations map.) All of the data are available on EPA's Air Quality System.[8] Ambient carbon monoxide levels in the Four Corners region are well below the level of the current NAAQS (see the CO trends and standards graph). Carbon monoxide levels nationwide are now very low due in large part to improved vehicle technology and emissions controls.

PM_{10} in the ambient air is, historically, the most heavily monitored pollutant in the Four Corners region. (See the PM_{10} site locations map.) Most of the monitoring has been performed using filter-based "high-volume" samplers that collect 24-hour samples and most of the data are available on EPA's Air Quality System.[8] Ambient PM_{10} levels in the Four Corners region are well below the level of the current and former NAAQS (see the PM_{10} trends graphs). As a result, some of the monitors were shut down at the end of 2006.

$PM_{2.5}$ in the ambient air has also been monitored at a number of locations in Four Corners region. (See the $PM_{2.5}$ site locations map.) Most of the monitoring has been performed using filter-based "low-volume" samplers that collect 24-hour samples and most of the data are available on EPA's Air Quality System.[8] Ambient $PM_{2.5}$ levels in the Four Corners region are well below the levels of the current NAAQS for both the 24-hour average and annual averages (see the $PM_{2.5}$ trends graphs). $PM_{2.5}$ has also been monitored as part of the IMPROVE network. These data are not on EPA's Air Quality System but may be obtained on the IMPROVE website.[9]

No monitoring for lead exists in the Four Corners region. Due to the introduction of unleaded gasoline in the 1970's, ambient lead levels have decreased to levels that are near instrument detection levels. Likewise, no monitoring exists for other pollutants such as carbon dioxide, HAPs or pesticides. While carbon dioxide is a greenhouse gas and is emitted from combustion sources, it is not considered to be toxic at typical ambient concentrations. Thus, there has been no specific reason for monitoring and no standards exist. No standards currently exist for organic compounds, including HAPs (such as volatile and semi-volatile organic compounds) and pesticides. Much of the monitoring for these compounds has been performed in urban areas where concentrations are expected to be higher, particularly for the HAPs, and more people are at risk for exposure. Several pilot and trends studies are currently underway across the nation, but the cost is very high for routine monitoring. Volatile organic compound baseline monitoring for San Juan County, New Mexico was conducted in 2004 and 2005 at three sites by the U.S. Environmental Protection Agency (EPA) Region 6. This study was primarily for ozone precursor organic compounds rather than for overall HAPs.[10,11]

Data Gaps:
Due to the very low levels of carbon monoxide, PM_{10} and $PM_{2.5}$ at existing or former air monitoring sites and at other surrounding areas, there is not expected to be any areas of the Four Corners region that need additional monitoring of these threeo pollutants to demonstrate NAAQS compliance. While there has been no monitoring for lead in the Four Corners region, the low levels that are seen nationwide and the lack of sources in the area indicate that no monitoring is likely to be needed. There is no NAAQS for carbon dioxide, so on a health basis, no monitoring is needed.

With organic compounds/HAPs and pesticides, there is little data for the area that exists. However, based on monitoring that is being performed nationwide in EPA's National Air Toxics Trends Study, there are not expected be concentrations that are much different from other areas. Due to the expense of monitoring, other areas would probably suffice as a surrogate. In addition, there are no significant major sources of HAPs in the region to warrant ambient monitoring. As part of "Ozone and Precursor Gases" suggestions, volatile organic compound/non-methane organic compound monitoring is being recommended. Pesticides may be a health issue for the agricultural population. This would lead to specific investigations rather than ambient monitoring sites.

Suggestions for Future Monitoring Work:

No suggestions for additional monitoring of carbon monoxide, PM_{10}, $PM_{2.5}$ and other common pollutants are currently being proposed.

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F. U.S. Environmental Protection Agency. http://www.epa.gov/air/urbanair/lead/index.html .
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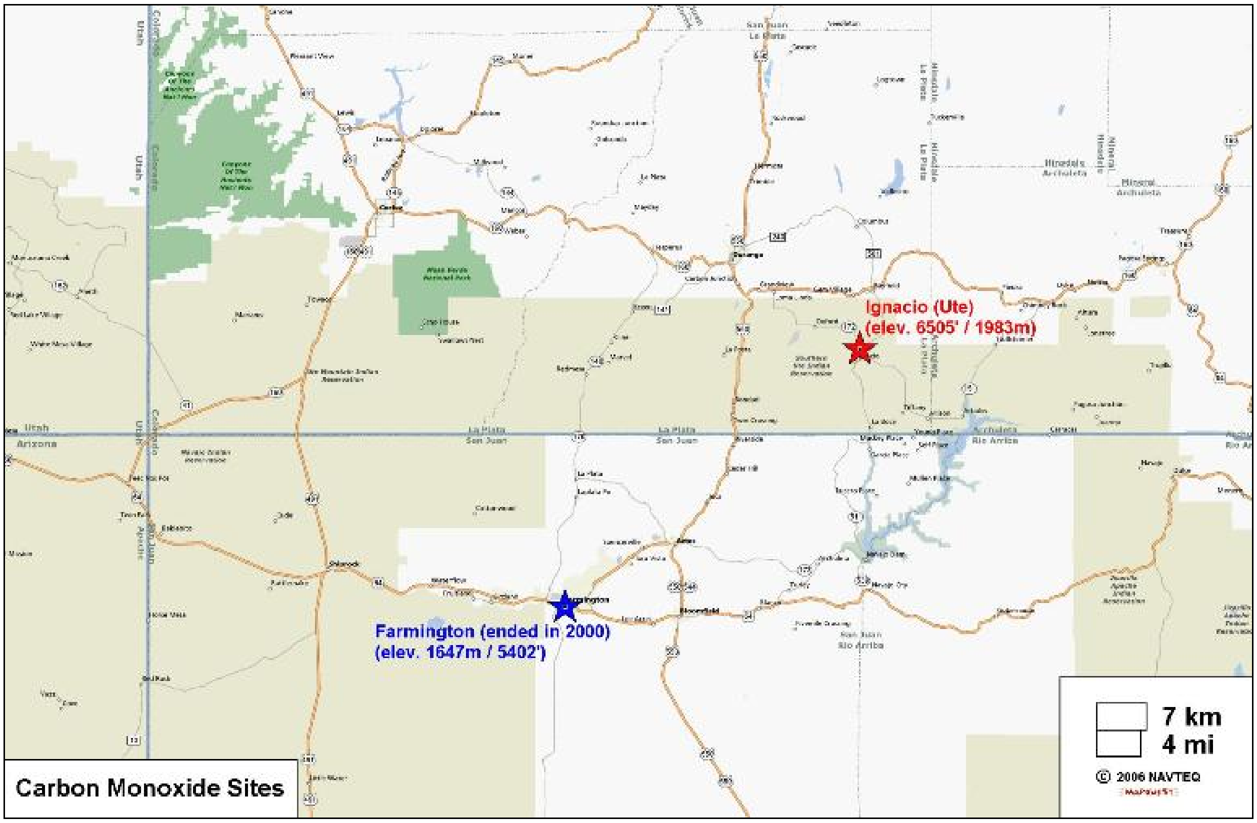
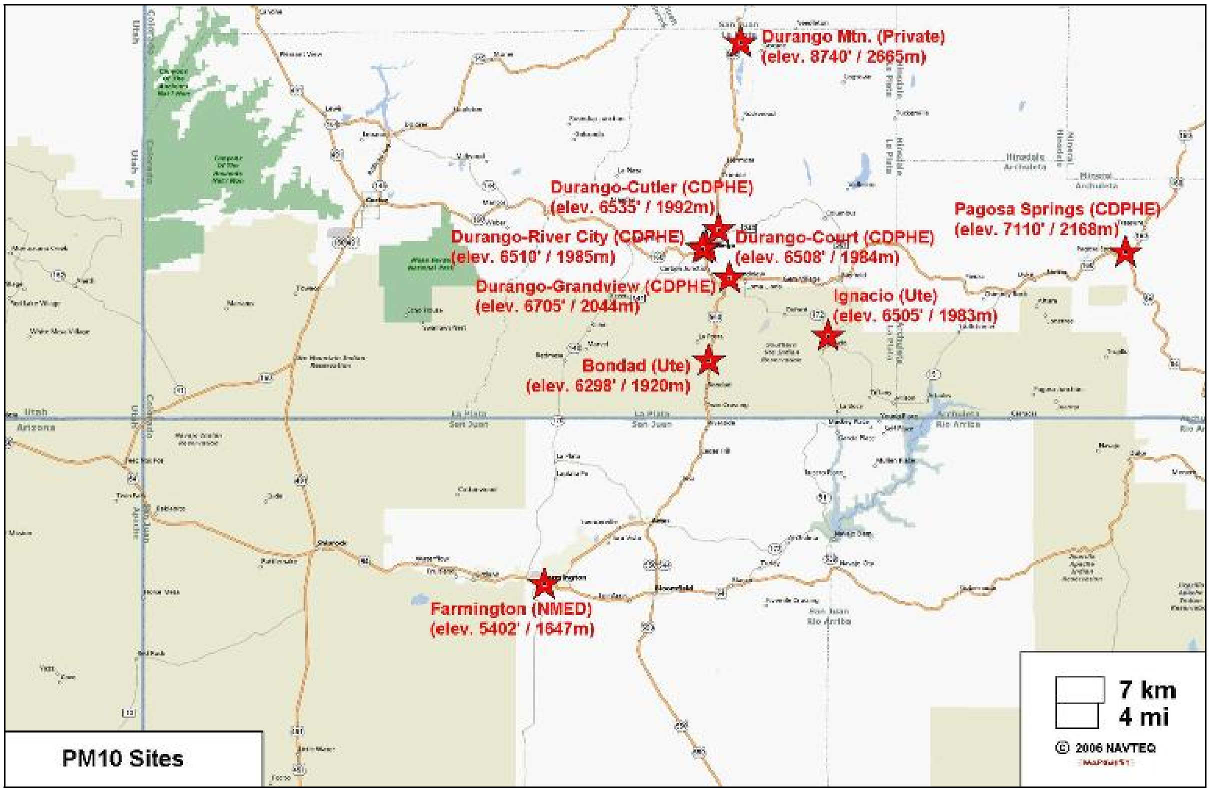
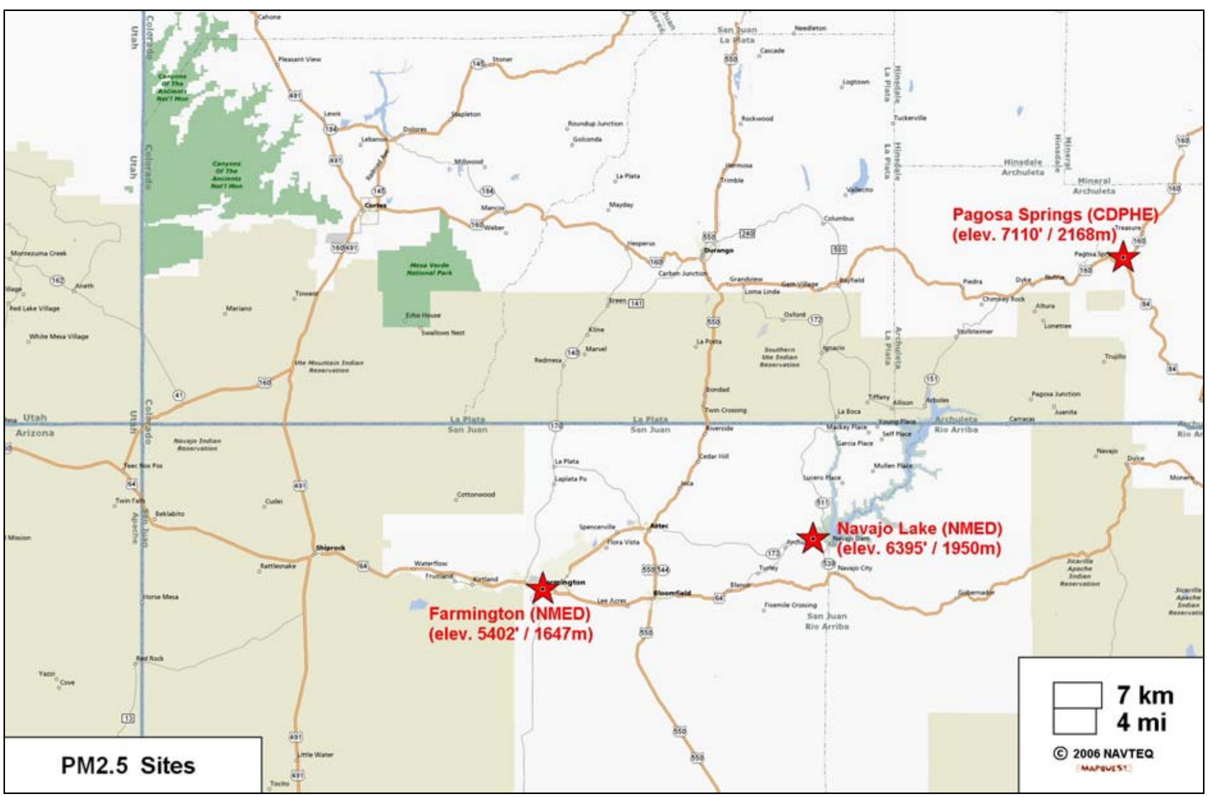
Four Corners --- Continuous Carbon Monoxide Sites in 2006

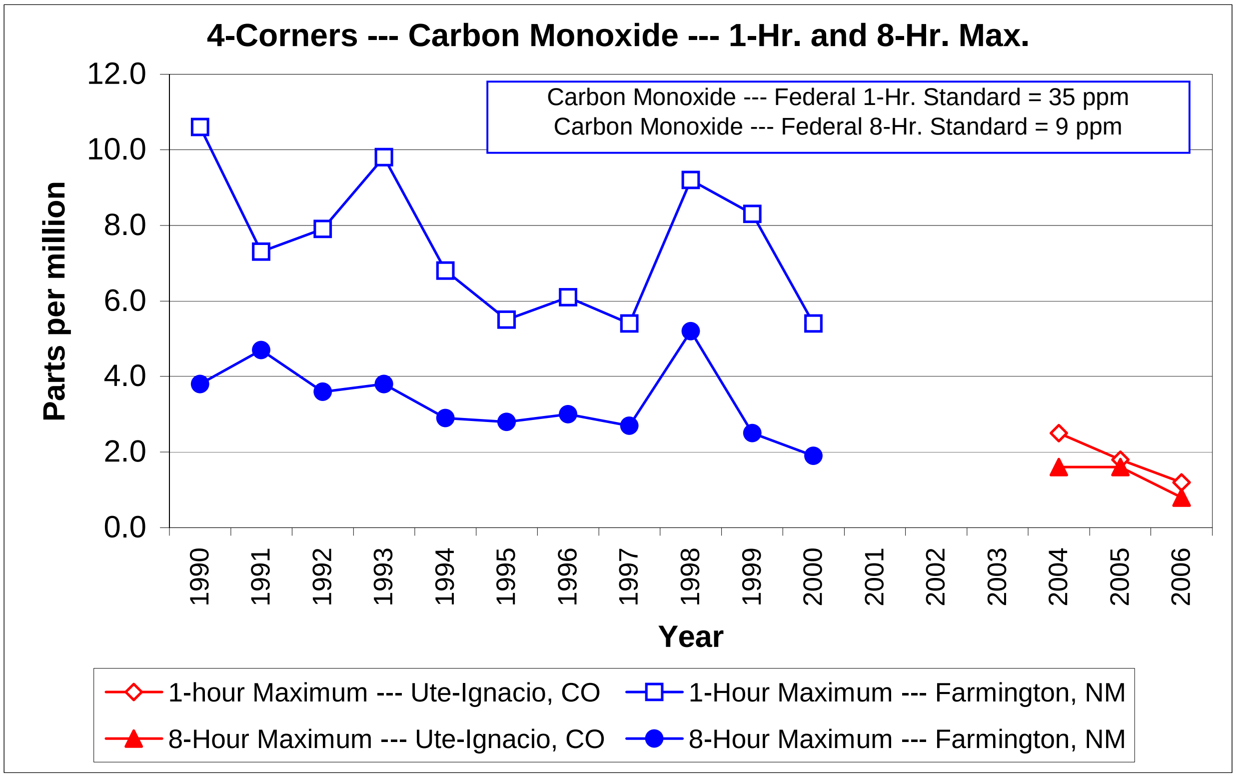


Four Corners --- Particulate Sites in 2006

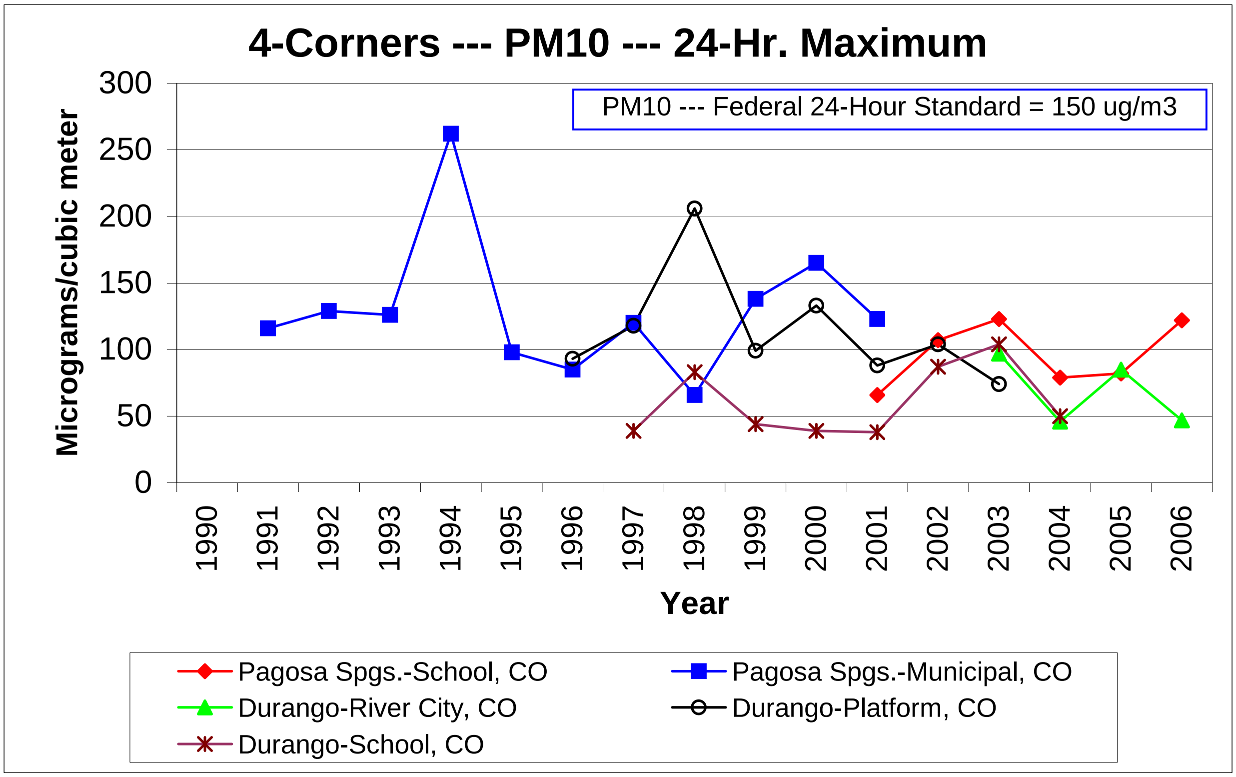


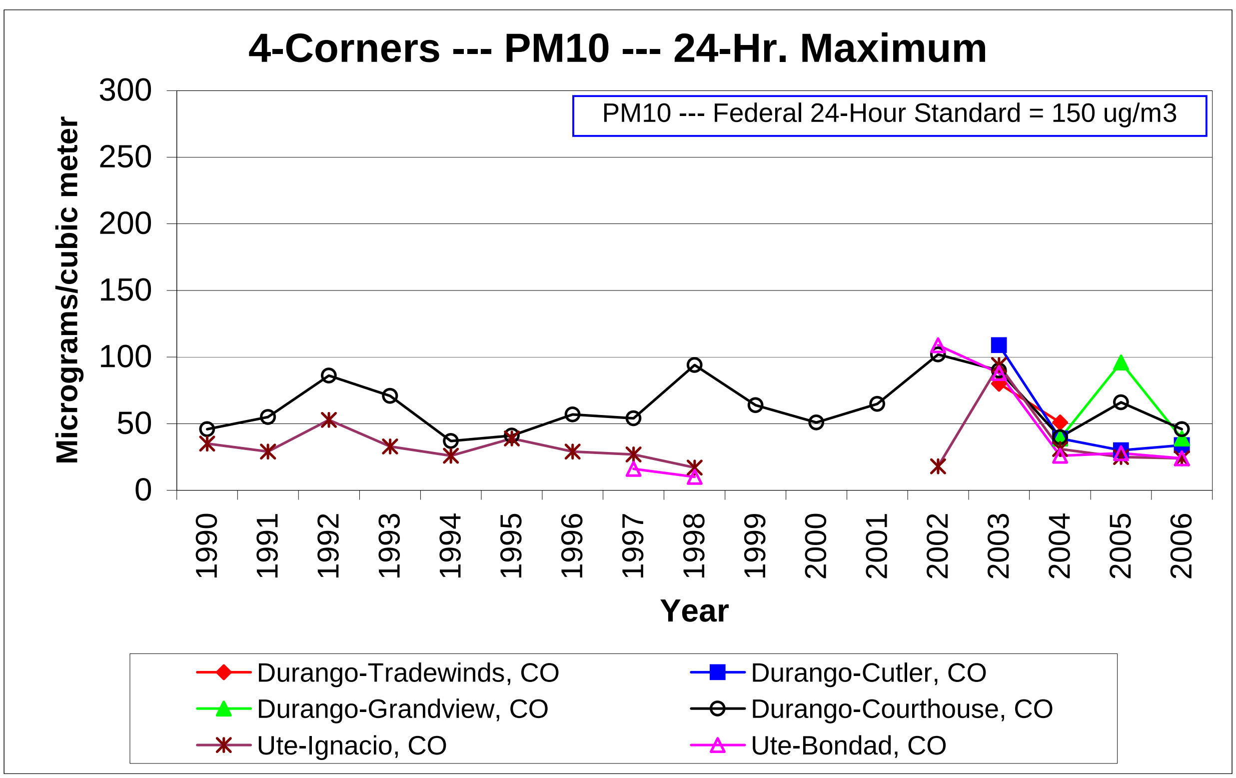


Four Corners --- Carbon Monoxide Trends (1-Hour and 8-Hour)

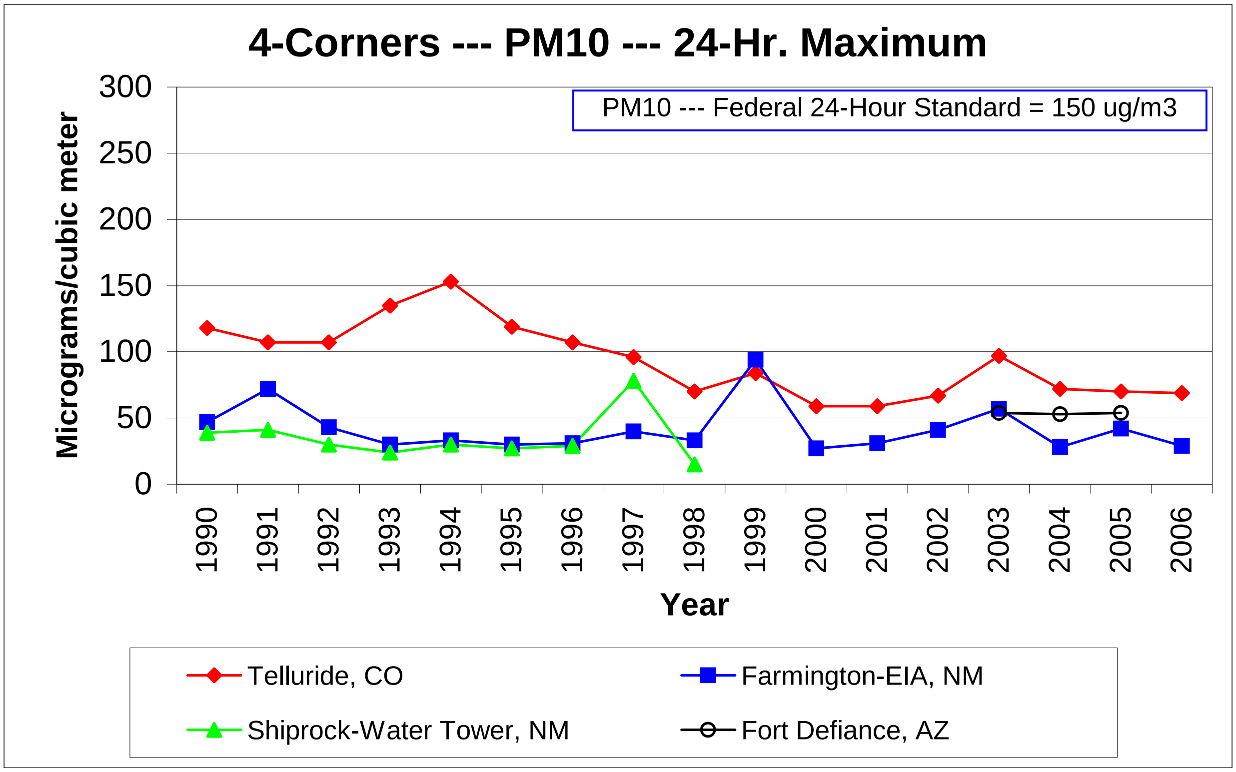


Four Corners --- PM_{10} Trends (24-Hour Maximum)

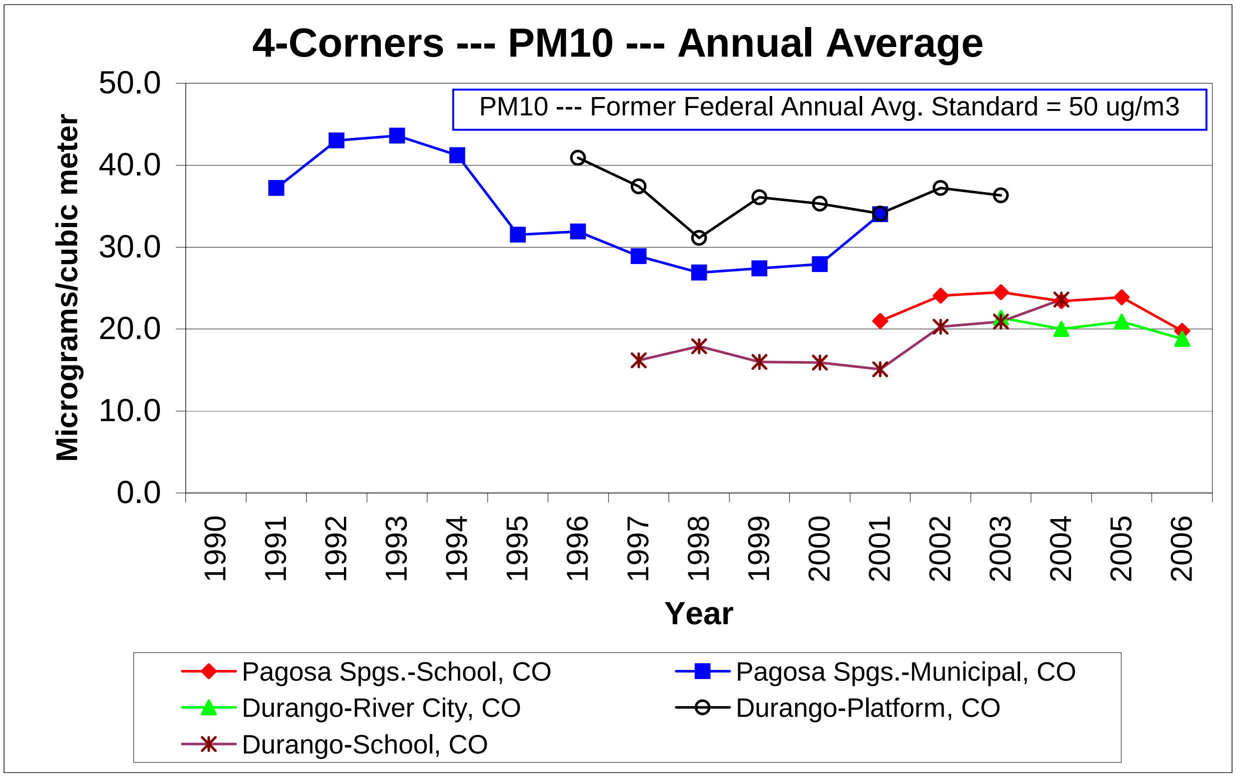


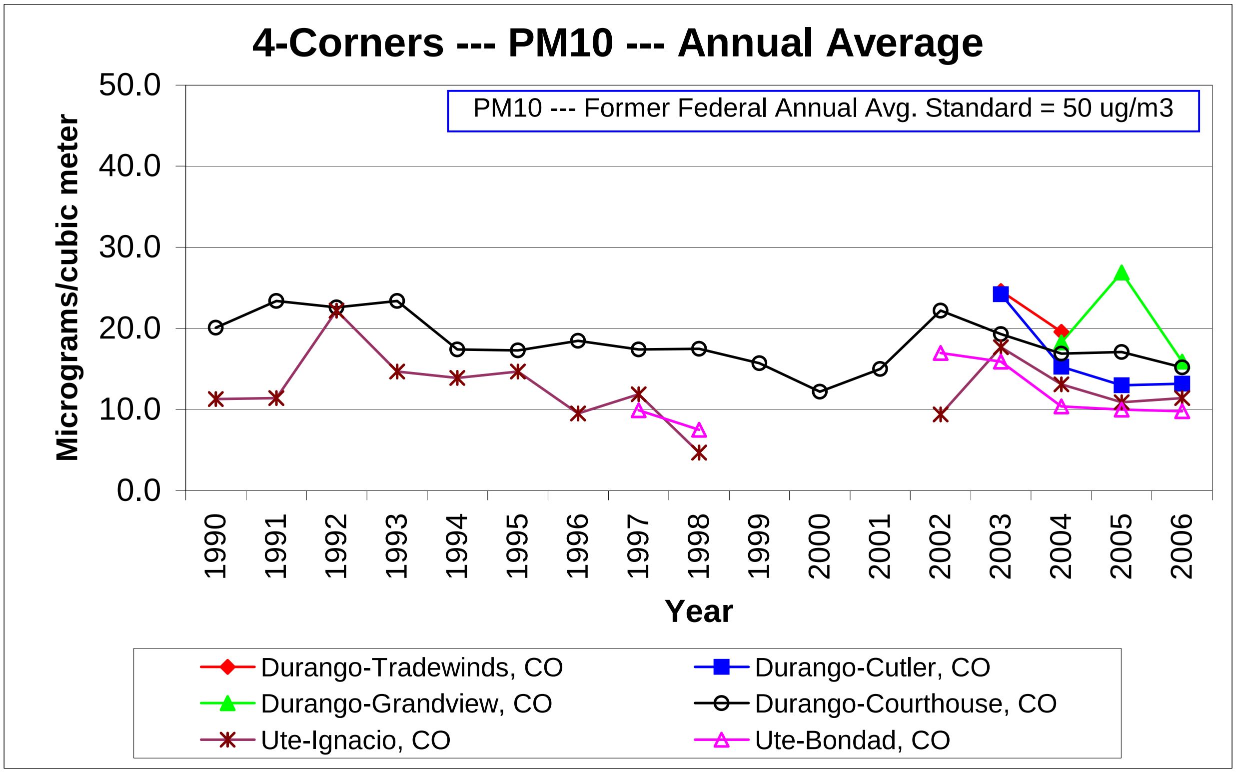


Four Corners --- PM_{10} Trends (24-Hour Maximum) – cont.

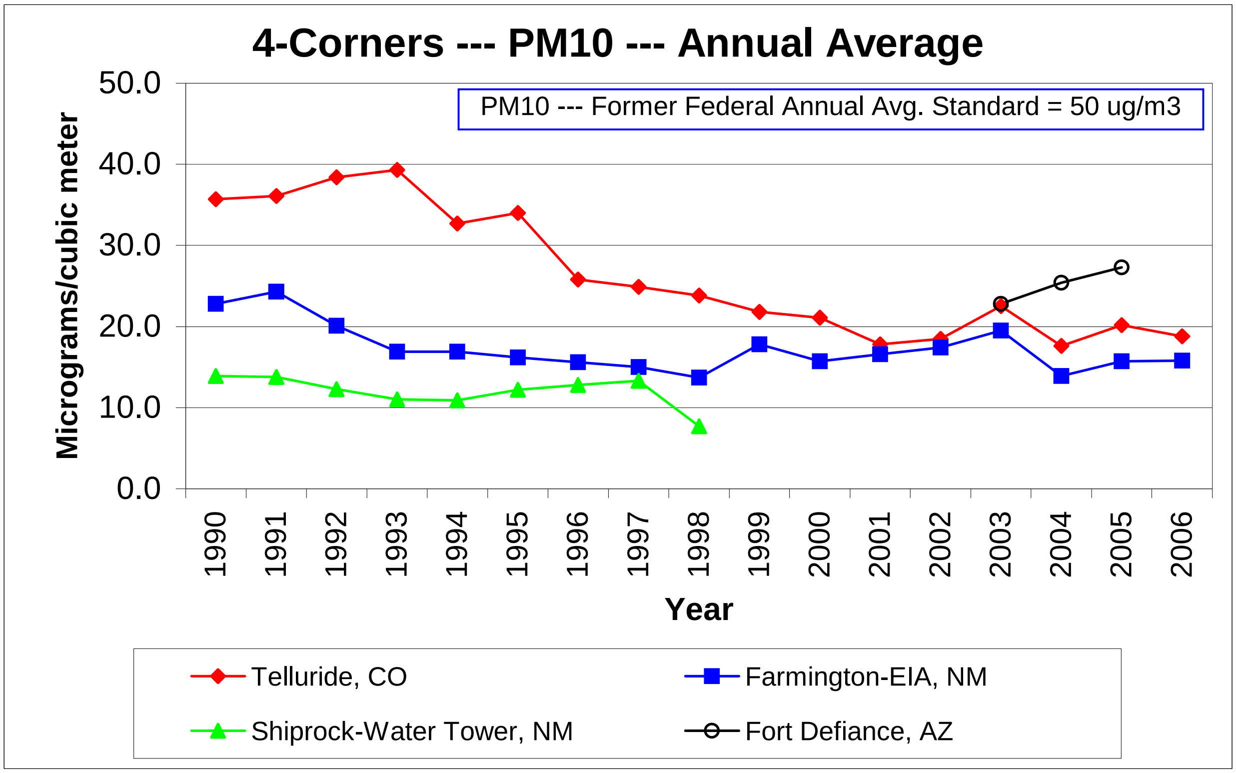


Four Corners --- PM_{10} Trends (Annual average)

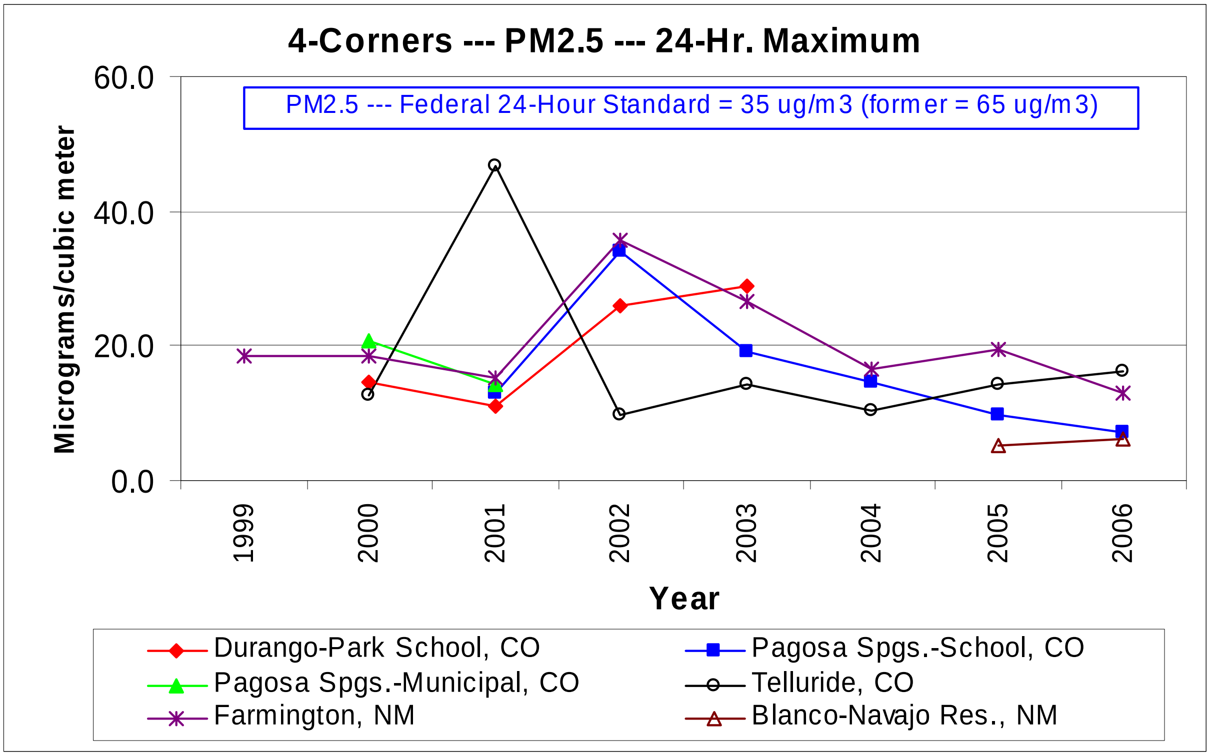




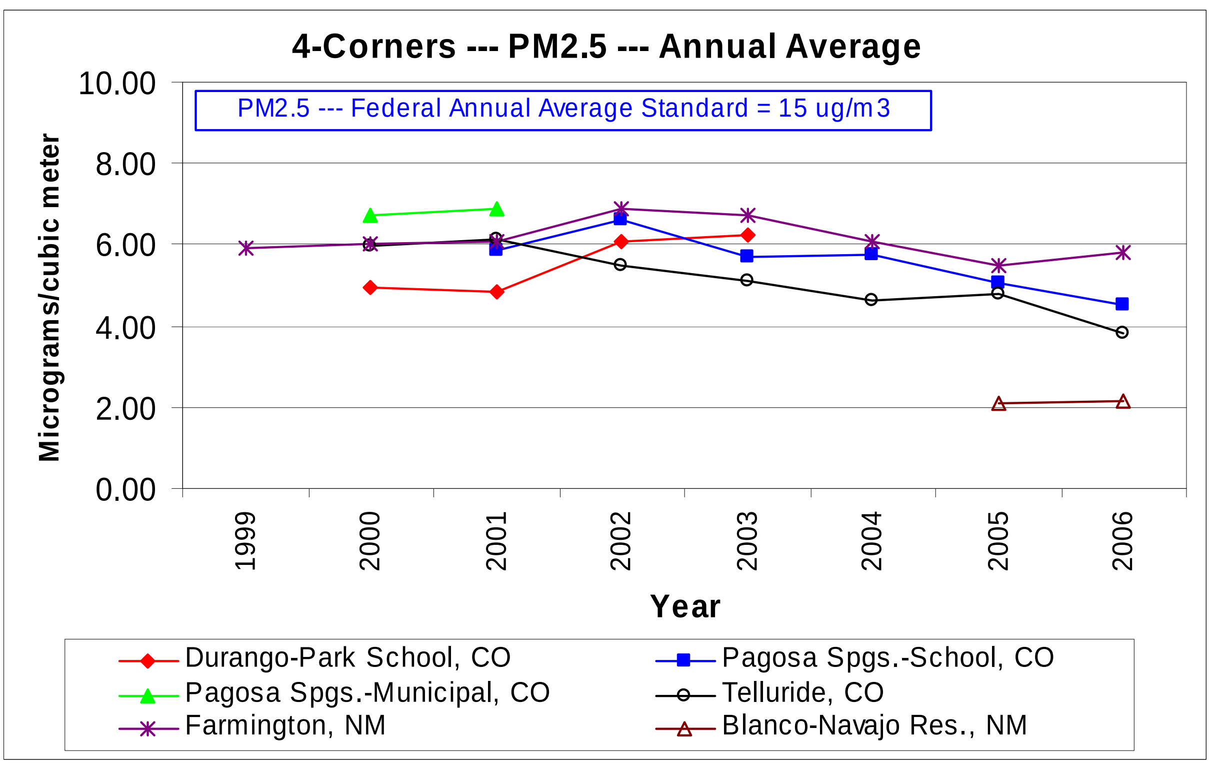
Four Corners --- PM_{10} Trends (Annual average) – cont.



Four Corners --- $PM_{2.5}$ Trends (24-Hour Maximum)



Four Corners --- $PM_{2.5}$ Trends (Annual average)



Uranium, Radionuclides and Radon

Background:

Rationale and Benefits:
Uranium is a naturally-occurring element found at low levels in virtually all rock, soil, and water. In a raw form, it is a silvery white, weakly radioactive metal. It has the highest atomic weight of the naturally occurring elements. Significant concentrations of uranium occur in some substances such as phosphate rock deposits, and minerals such as uraninite in uranium-rich ores. The largest single source of uranium ore in the United States is the Colorado Plateau region, located in Colorado, Utah, New Mexico, and Arizona.[1] Radionuclides are unstable nuclides of elements and may be natural or man-made in origin. Radon is a naturally occurring radioactive gas that is a decay product.

Uranium in soil and rocks is distributed throughout the environment by wind, rain and geologic processes. Rocks weather and break down to form soil, and soil can be washed by water and blown by wind, moving uranium into streams and lakes, and ultimately settling out and reforming as rock. Uranium can also be removed and concentrated by people through mining and refining. These mining and refining processes produce wastes such as mill tailings which may be introduced back into the environment by wind and water if they are not properly controlled. Manufacturing of nuclear fuel, and other human activities also release uranium to the environment.[2]

It is important to keep in mind that uranium is naturally present in the environment (both in air and in water) and is in your normal diet, so there will always be some level of uranium in all parts of your body.[3] The average daily intake of uranium from food ranges from 0.07 to 1.1 micrograms per day. About 99 percent of the uranium ingested in food or water will leave a person's body in the feces, and the remainder will enter the blood. Most of this absorbed uranium will be removed by the kidneys and excreted in the urine within a few days. A small amount of the uranium in the bloodstream will deposit in a person's bones, where it will remain for years.[2]

The greatest health risk from large intakes of uranium is toxic damage to the kidneys, because, in addition to being weakly radioactive, uranium is a toxic metal. Uranium exposure also increases the risk of getting cancer due to its radioactivity. Since uranium tends to concentrate in specific locations in the body, risk of cancer of the bone, liver cancer, and blood diseases (such as leukemia) are increased. Inhaled uranium increases the risk of lung cancer.[2] In addition, uranium can decay into other radioactive substances, such as radium, which can cause cancer if exposed to enough of them for a long enough period of time.[3]

The Occupational Safety and Health Administration has set occupational exposure limits for uranium in breathing air over an 8-hour workday, 40-hour workweek. The limits are 0.05 milligrams per cubic meter (0.05 mg/m^3) for soluble uranium dust and 0.25 mg/m^3 for insoluble uranium dust.[3] Uranium in drinking water is covered under the Safe Water Drinking Act, which establishes maximum contaminant levels, or MCLs, for radionuclides and other contaminants in drinking water. The uranium limit is 30 µg/l (micrograms per liter) in drinking water. The Clean Air Act limits emissions of uranium into the air where the maximum dose to an individual from uranium in the air is 10 millirem.[4] There are no Federal ambient air standards for uranium.

The isotope ^{235}U is useful as a fuel in power plants and weapons. To make fuel, natural uranium is separated into two portions. The fuel portion has more ^{235}U than normal and is called enriched uranium. The leftover portion with less ^{235}U than normal is called depleted uranium, or DU. Natural, depleted, and enriched uranium are chemically identical. Depleted uranium is the least radioactive and enriched uranium the most.[3]

Due to concerns on foreign oil dependence and global warming, renewed interest is being shown in nuclear power generation. The Colorado Plateau, as noted above, has a high concentration of uranium ore. As a result, there is increasing interest in the area for both uranium mining and milling. Of particular concern are milling operations where the mill tailings are rich in the chemicals and radioactive materials that were not removed. In the milling process, the ore is crushed and sent through an extraction processes to concentrate the uranium into uranium-oxygen compounds called yellowcake. The remainder of the crushed rock, in a processing fluid slurry, is placed in a tailings pile.[5] The most important radioactive component of uranium mill tailings is radium, which decays to produce radon.

The radium in these tailings will not decay entirely for thousands of years. Other potentially hazardous substances in the tailings are selenium, molybdenum, uranium, and thorium.[4]

In the Four Corners area, there is currently one operating uranium mill, located near Blanding Utah. A mill has also been proposed near Naturita in western Colorado. Mining operations have also been proposed in San Miguel County in Colorado. This has led to concerns over potentially increased exposures to radionuclides, radon and contaminated dusts from both mills/tailings piles and mines. Immediate concerns would be to the general public in the immediate vicinity of these facilities/operations. However, there are also concerns over longer range air transport of radionuclides, radon and contaminated dusts for the region, especially as the number of these facilities/operations may increase significantly.

Existing uranium data for the Four Corners region:
Currently, little current ambient air monitoring data exists for uranium in the Four Corners region. Neither the States of Colorado nor Utah are currently performing any monitoring around uranium mining or milling operations. From historical mining and milling, total suspended particulate and radionuclide data exist from private monitoring.

As part of National Emissions Standards for Hazardous Air Pollutant regulations (through the U.S. Environmental Protection Agency), monitoring is required to be performed to assess and limit emissions of radon and radionuclides from mines, mills and tailings.[6] U.S. Nuclear Regulatory Commission guidelines call for both onsite and offsite particulate monitoring for radionuclides, radon monitoring and meteorological monitoring at uranium mills. This monitoring is required both prior to operation and during operation.

Data Gaps:
While little ambient air monitoring data exists for uranium mine and milling operations/facilities, emissions monitoring and modeling is required under National Emissions Standards for Hazardous Air Pollutant regulations. Ambient air monitoring is required under Nuclear Regulatory Commission guidelines. Based on this, it is expected that uranium, radionuclide and radon emissions from these facilities/operations is low and should pose no threat to the general public either locally or at a distance. However, as additional facilities become operational, the overall uranium, radionuclide and radon emissions in the Four Corners area will increase and may be significant.

Recommendations:

No recommendations for additional ambient air monitoring of uranium, radionuclides or radon are currently being proposed. However, as uranium mining and milling activities in the Four Corners region increase, this topic may need to be revisited.

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Mercury

Background:

Rationale and Benefits: Methyl mercury is a known neurotoxin affecting humans and wildlife. Coal-fired power plants are the number one source of mercury emissions in the United States[1]. The Four Corners already is home to several power plants that are large emitters of mercury and additional coal-powered plants are proposed for the region. Individuals and community groups in the Four Corners region have expressed great concern about mercury emissions in our region and the existing mercury fish consumption advisories in several reservoirs. Studies of mercury in air deposition, the environment and in sensitive human populations (such as pregnant women) are necessary to set a baseline for current levels and to detect future impacts of increased mercury emissions on these sensitive human populations and natural resources, including the Weminuche Wilderness and Mesa Verde National Park, which are both Federal Class I Areas.

Existing mercury data for the Four Corners region: Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network (MDN)(Figure 1)[2]. Results show mercury concentrations among the highest in the nation during certain years. Precipitation is relatively low, however, so mercury in wet deposition is moderate (Figure 3)[2]. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS and moderate concentrations similar to the Colorado Front Range have been recorded[3]. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for water bodies including McPhee, Narraguinnep, Todden, Navajo, Sanchez and Vallecito Reservoirs and segments of the San Juan River (Figure 4)[4]. Sediment core analysis for Narraguinnep Reservoir show that mercury fluxes increased by approximately a factor of two after about 1970[5]. Finally, atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these water bodies, respectively[6].

Data Gaps: Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. No data exists for mercury in deposition at high elevations. Wet deposition of mercury at Mesa Verde National Park may not portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of water bodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

Three new studies have begun or will begin in 2007, however. The Mountain Studies Institute (MSI) will measure total mercury in bulk atmospheric deposition (collector near NADP station at Molas Pass, 10, 659 ft. elevation), in lake zooplankton (invertebrates eaten by fish), and in lake sediment cores in the San Juan Mountains, a project funded by the U.S. EPA and USFS[8]. Dr. Richard Grossman is measuring mercury levels in hair collected from pregnant women in the Durango vicinity. Lastly, the Pine River Watershed Group (via the San Juan RC&D) recently was granted start-up funds from La Plata County to initiate event-based sampling of mercury in atmospheric deposition at Vallecito Reservoir and accompanying back-trajectory analyses to locate the source of these storm events.

Suggestions for Future Monitoring Work:

1. Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the

NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

2. Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

3. Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., suggestions 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html9). Costs TBD.

Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

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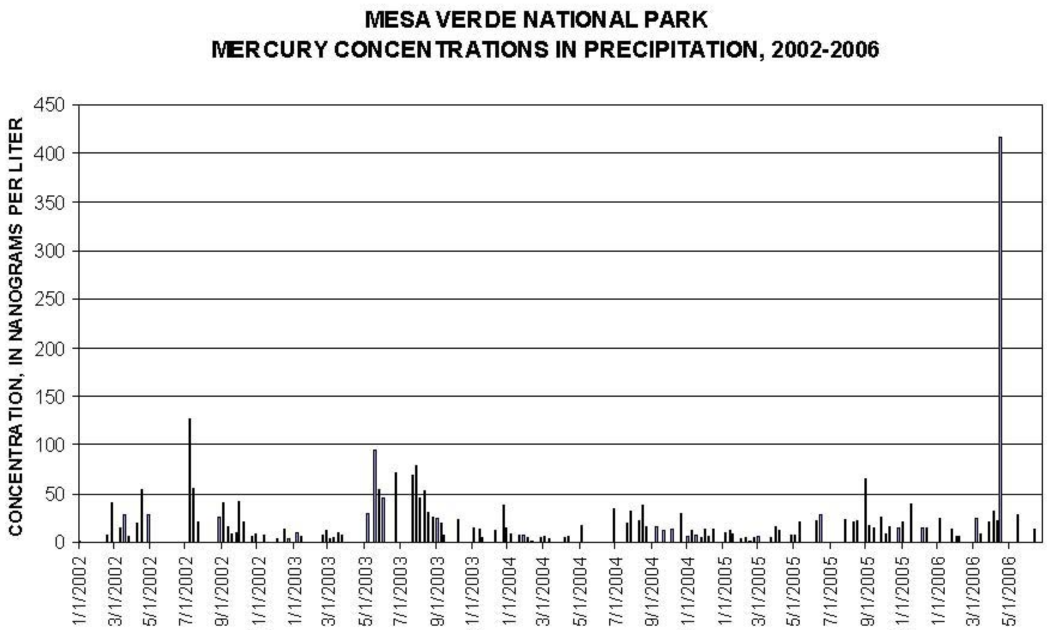
Figures



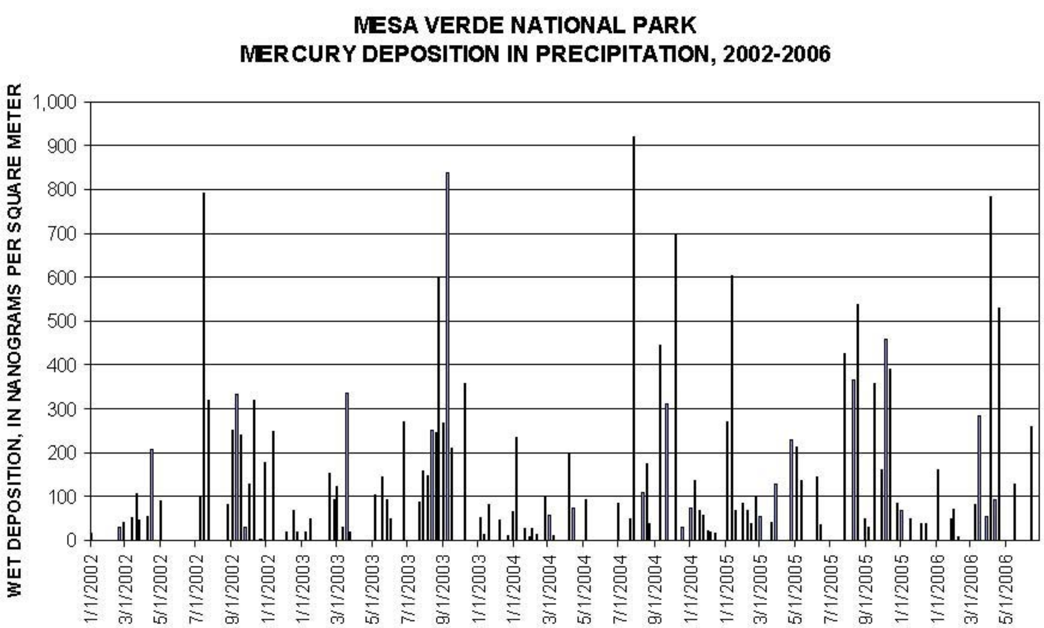
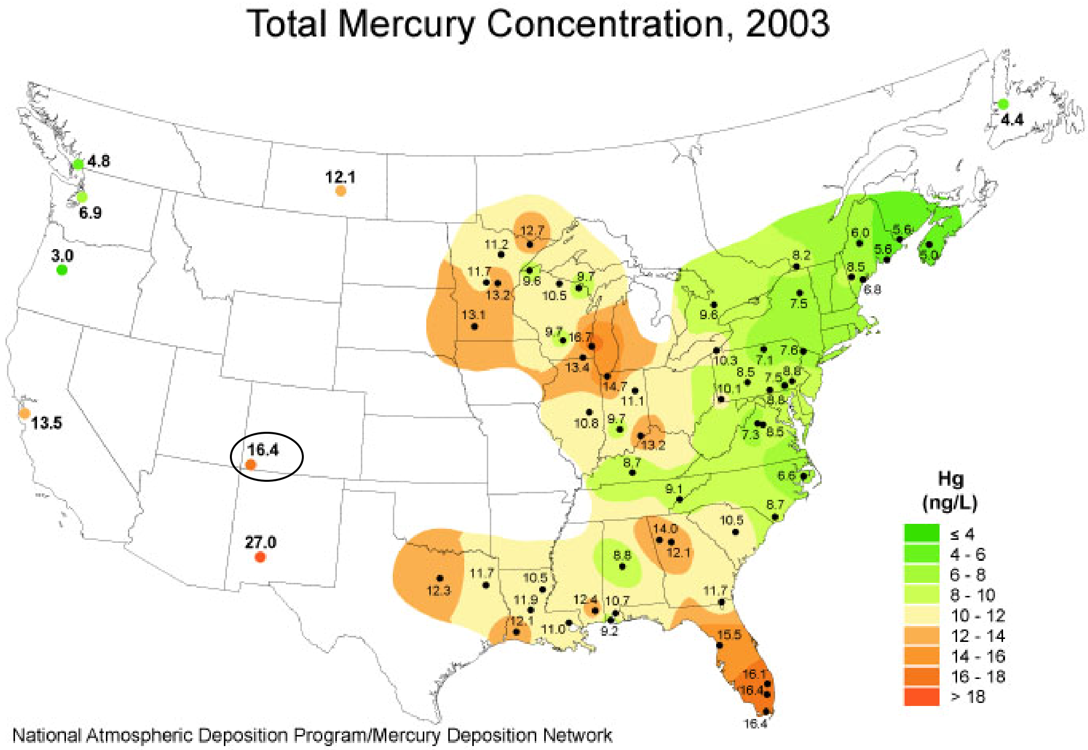


Figure 1. Concentrations and wet deposition of mercury at Mesa Verde National Park, 2002-2006. Data are from the National Atmospheric Deposition Program, Mercury deposition Network.



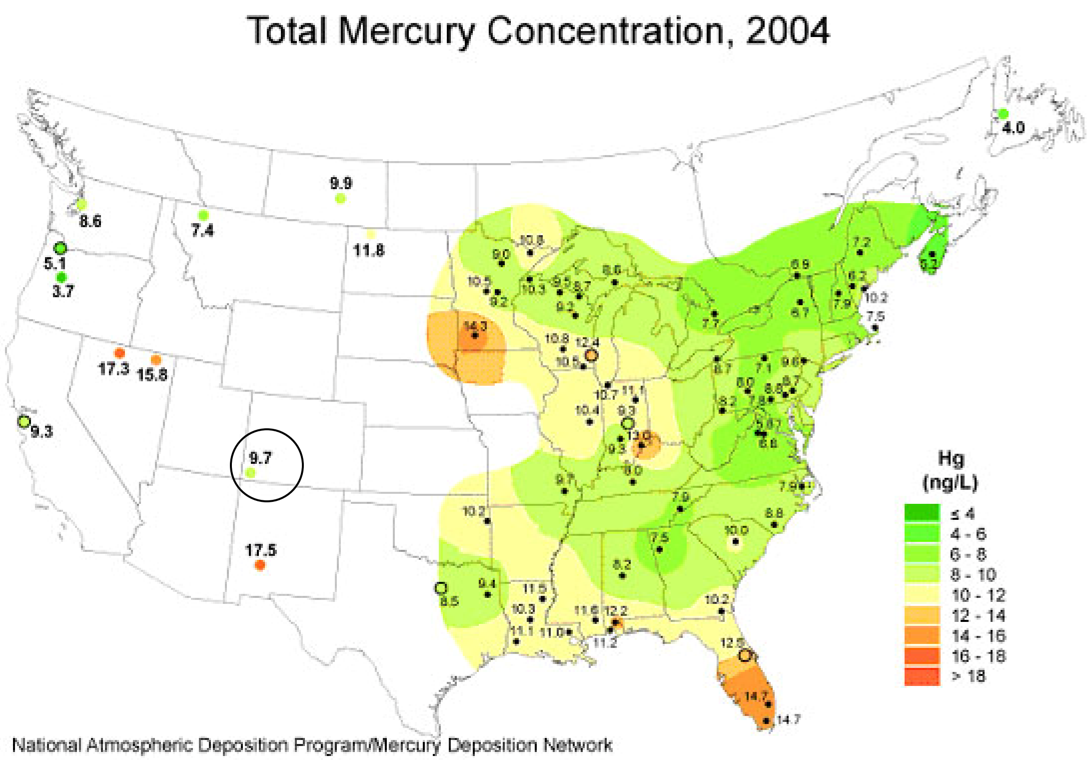
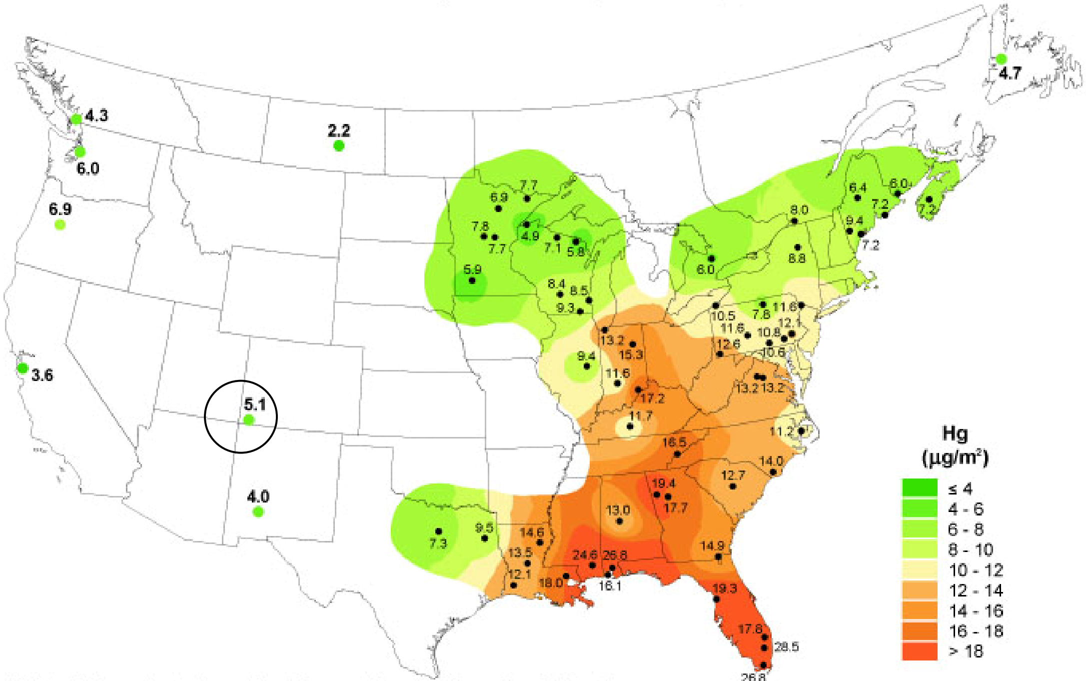


Figure 2. Volume-weighted mean concentrations of mercury in wet deposition at MDN monitoring stations across the United States for 2003 (top) and 2004 (bottom). Mesa Verde National Park is circled.

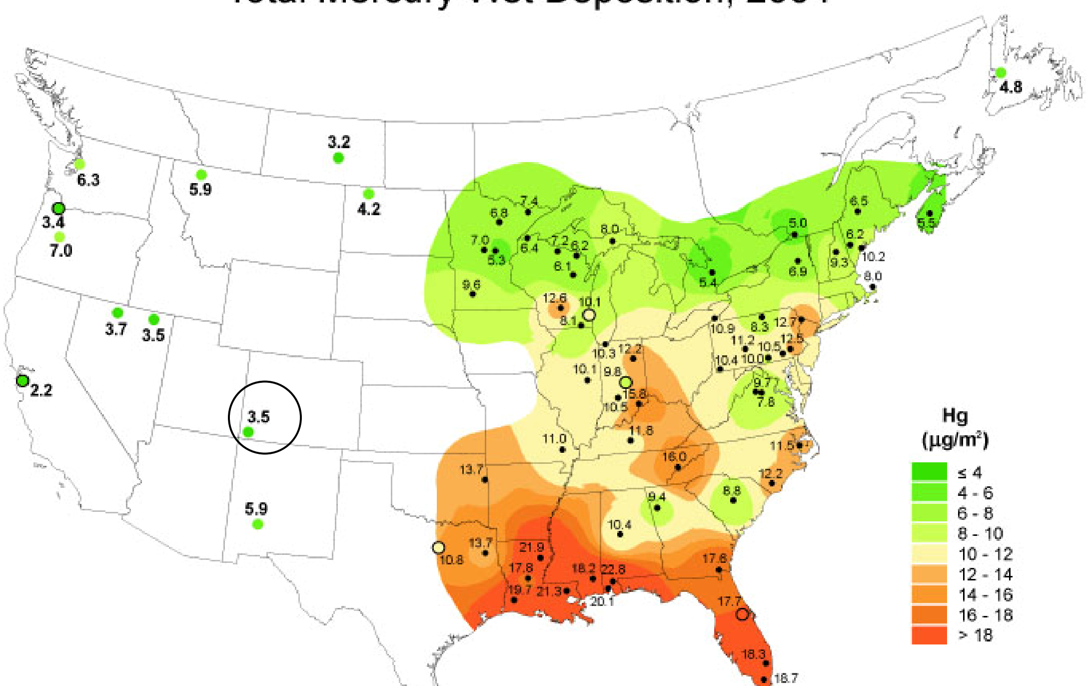
The years 2003 and 2004 represent “high” and “low” average annual concentrations for the Park’s short data record, 2002-2006.

Total Mercury Wet Deposition, 2003



National Atmospheric Deposition Program/Mercury Deposition Network

Total Mercury Wet Deposition, 2004



National Atmospheric Deposition Program/Mercury Deposition Network

Figure 3. Total mercury wet deposition at MDN monitoring stations across the United States for 2003 (top) and 2004 (bottom). Mesa Verde National Park is circled. While concentrations are high (Figure 2), total wet deposition of mercury is low to moderate due to low precipitation amounts at Mesa Verde.

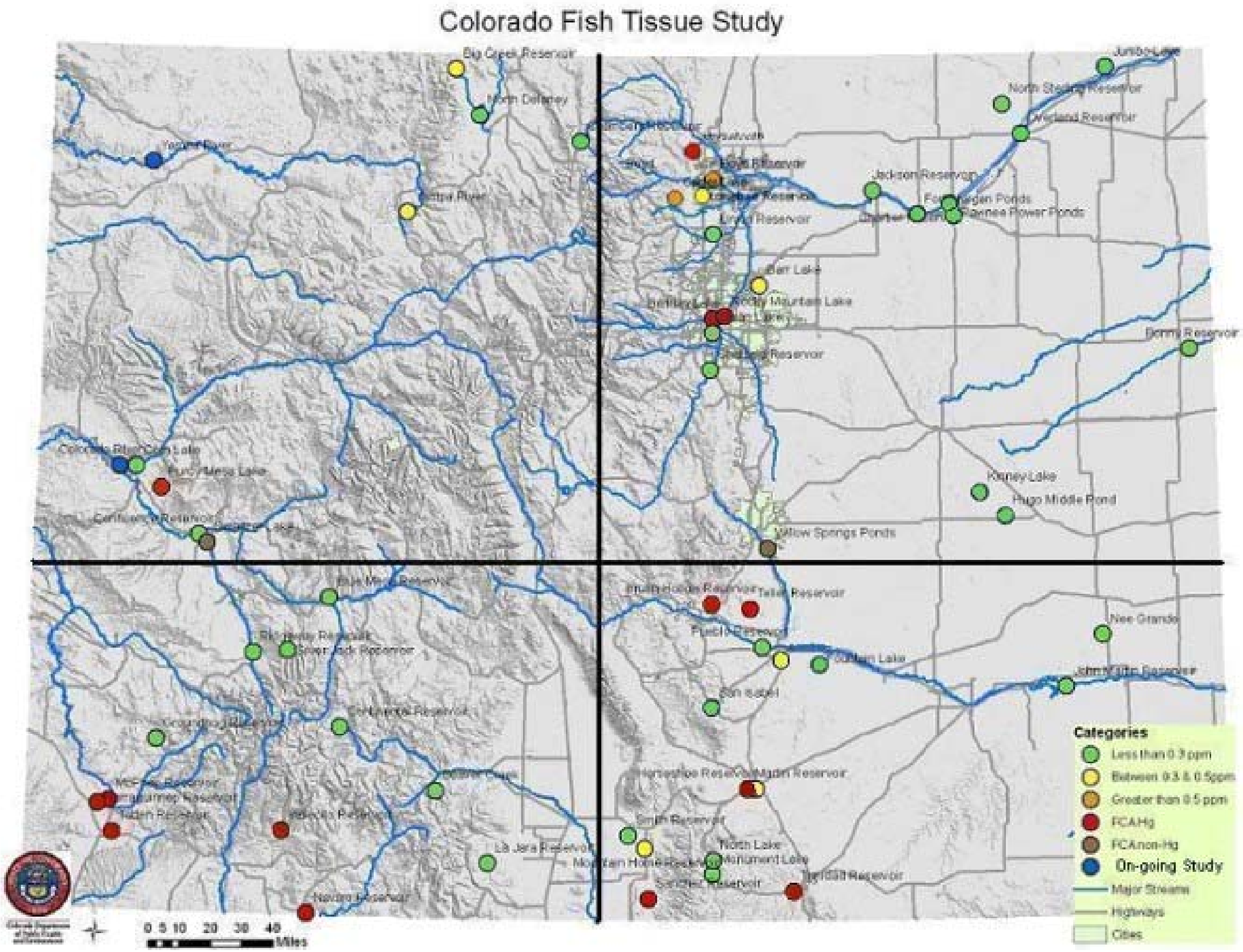


Figure 4. Results of a study by the Colorado Department of Public Health and Environment (CDPHE) measuring mercury concentrations in fish tissue in selected water bodies. The sites marked in red already have consumption advisories posted on them. Advisories are triggered by having a mercury level of 0.5 parts per million or more. The sites in orange have a similar mercury concentration to the red and are in the process of having consumption advisories posted on them as well. The sites marked in yellow have mercury levels between 0.5ppm and 0.3ppm. These are water bodies that the CDPHE is keeping a close watch on, although they are not recommending restricting consumption. The sites marked in green have mercury concentrations below 0.3ppm. The green sites are also not recommended for restricted consumption. Figure from CDPHE's Colorado Fish Tissue Study, [http://www.cdphe.state.co.us/wq/FishCon/analyses/index.html.](http://www.cdphe.state.co.us/wq/FishCon/analyses/index.html)

Atmospheric Deposition of Nitrogen and Sulfur Compounds

Background:

Rationale:

Nitrogen (N) is an essential nutrient, but in elevated amounts it can cause harmful effects to ecosystems and human health. In areas with minimal human development, N in air deposition is a major contributor to N inputs to ecosystems, including surface waters. Air deposition includes wet deposition received with precipitation, but also includes dry deposition of gases and aerosols, through fall deposited under forest canopies, and condensation of cloud and fog. Atmospheric N mainly is deposited as nitrate, nitric acid, ammonium, and dissolved organic nitrogen. Key anthropogenic sources include nitrogen oxides (NOx) emitted from fossil fuel burning and ammonia volatized from fertilizer and animal wastes. NOx also will react with volatile organic compounds to form ozone (see ozone sub-chapter). Increased deposition of atmospheric N can result in high levels of nitrate in surface and ground water, shifts in species, decreased plant health, and eutrophication (i.e., fertilization) of otherwise naturally low-productivity ecosystems. Both N and sulfur (S) oxides can form "acid rain" and lead to acidification of surface and groundwater and soils. S oxides primarily are emitted to the atmosphere by burning of fossil fuels.

Atmospheric deposition of S has decreased at many monitoring stations in the USA, especially in the eastern portion, since the implementation of the Clean Air Act Title IX Amendments. Despite a few locations with slight increases in S, amounts and concentrations of sulfate in wet deposition generally are low in the western USA. In contrast, concentrations of nitrate and ammonium in wet deposition have increased at some monitoring stations in the USA, including many in the western portion (Figures 1-3).[1, 2]

Harmful ecological effects of elevated N deposition have been documented in the western United States in regions downwind of emissions hotspots, including both high and low-elevation ecosystems[3]. These effects include high nitrate concentrations in streams and lakes, reduced clarity of lakes, altered and less diverse aquatic algal and terrestrial plant communities, loss of N from soils via leaching and gas flux, increased invasive species, changed forest carbon cycle and fuel accumulation, altered fire cycles, harm to threatened and endangered species, and contribution to regional haze and ozone formation[3]. In the Colorado Front Range, including the east side of Rocky Mountain National Park, harmful ecosystem effects attributed to increased N deposition specifically include: chronically elevated levels of nitrate in surface waters, altered types and abundances of aquatic algal species (diatoms), elevated levels of N in subalpine forest foliage, long-term accumulation and leaching of N from forest soils, and shifts in alpine plants from wildflowers to more grasses and sedges[3,4,5]. Hindcasting of deposition trends estimate that the harmful effects in the CO Front Range began when N in wet deposition increased above the 1.5 kg/ha/yr threshold[6]. An ecological critical load is the quantitative estimate of an exposure to one or more pollutants below which significant harmful effects on specified sensitive elements of the environment do not occur according to present knowledge[7]. Rocky Mountain National Park has adopted 1.5 kg/ha/yr of N in wet deposition as its ecological critical load[8] and the Colorado Department of Public Health and Environment's Air Pollution Control Division is now working to reduce N deposition loads to the Park[9].

Existing N & S deposition and ecological effects data for the Four Corners and San Juan Mountain region:

Currently, monitoring stations for N, S, and H+ in wet deposition exist at Mesa Verde National Park (since 1981), Molas Pass (since 1986), and Wolf Creek Pass (since 1992) as part of the National Atmospheric Deposition Program (NADP)[10]. Dry deposition of N and S, which is especially important in arid regions (Fenn et al. 2003), has been monitored since 1995 at Mesa Verde NP as part of the Clean Air Status and Trends Network (CASTNet). Concentrations of airborne aerosols such as ammonium nitrate and ammonium sulfate are reported as part of the Interagency Monitoring of Protected Visual Environments (IMPROVE) program at Mesa Verde National Park and a site near Durango Mountain Resort (Weminuche Wilderness).

Trends of sulfate concentrations in wet deposition show either a decrease over time or no change at monitoring stations in the vicinity of the Four Corners region. Conversely, trends of nitrate and ammonium concentrations in wet deposition appear to be stable or increasing (Figure 4)[10,11]. In general, N in wet deposition in the Four Corners and San Juan Mountain region currently is at or above the 1.5 kg/ha/yr ecological critical load discussed above for

Rocky Mountain National Park. Dry deposition data from Mesa Verde NP indicate that, for the period 1997-2000, dry deposition contributed about half of the total inorganic nitrogen deposition and about one-third of the total sulfur deposition. The short data record is insufficient to detect trends over time for dry deposition. Model simulations of total wet plus dry deposition of N in the western United States indicate a possible hotspot for N deposition in SW Colorado (Figure 5)[12].

Inorganic water chemistry for Wilderness Lakes has been collected by the USDA-National Forest Service and US Geological Survey and over 15 years of data have accumulated for some lakes. While some of this data has been compared to high-elevation lake water chemistry in other regions of Colorado and Wyoming[13], a full analysis has not been completed. Furthermore, the data are insufficient to detect potential changes to lake biology.

Data Gaps: While data for N in wet deposition exist from multiple sites in the region, dry deposition is studied only at Mesa Verde National Park, which does not represent higher-elevations common near the Four corners region. Data concerning ecological effects of N deposition are very sparse for both high and low elevations and the limited data that do exist have not been analyzed adequately. No data exists for N and S deposition in the vicinity of emission sources. For example, no monitoring of N and S in wet or dry deposition occurs in NW New Mexico with the exception of Bandelier National Park.

Suggestions for Future Monitoring Work:

C. Continue monitoring for N, S and H+ in wet deposition via the NADP at the Molas Pass, Wolfe Creek Pass and Mesa Verde National Park sites. Consider adding a site closer to emissions sources in NW New Mexico.

D. Initiate long-term monitoring / modeling of N and S in dry deposition via the Clean Air Status and Trends Network (CASTNet) at a site such as Molas Pass, which is at higher elevation than the one existing site at Mesa Verde NP. Consider adding an additional site closer to emissions sources in NW New Mexico.

E. Complete a full analysis of existing Wilderness Lakes data, including spatial and temporal trends and correlation of measurements with watershed or lake characteristics.

F. Support a suite of ecological studies in order to measure potential harmful effects of N deposition on natural resources across an elevation gradient. The studies should include an observational component aimed at documenting changing ambient conditions, but experimental manipulations should also be used to understand cause and effect relationships in addition to potential future responses. These studies should be modeled after those conducted in the Colorado Front Range, California, etc. (see Fenn et al. 2003)[3].

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Figures

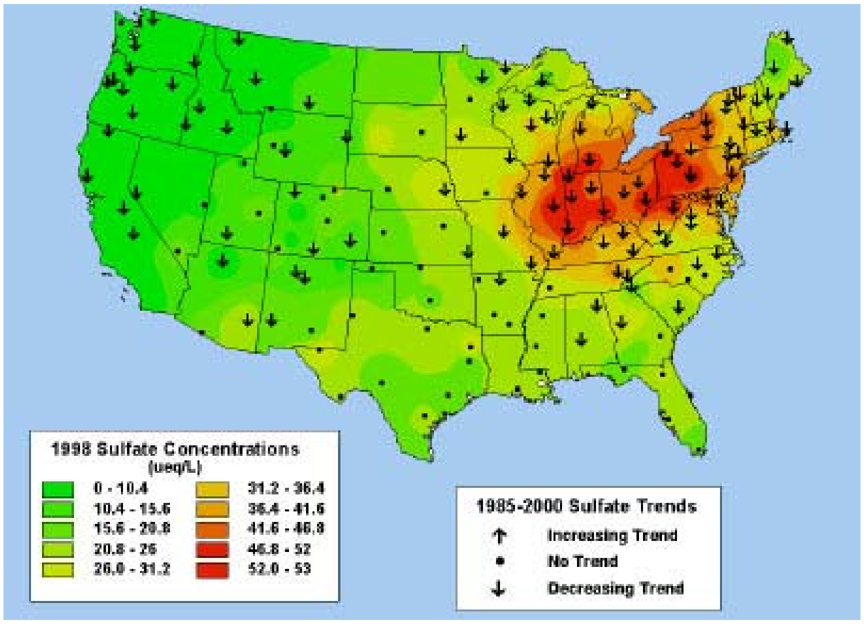


Figure 1. Trends in sulfate concentrations in wet deposition, 1985-2000. Sulfate concentrations are low in the Four Corners region and either show no trend or a decreasing trend over time[2]

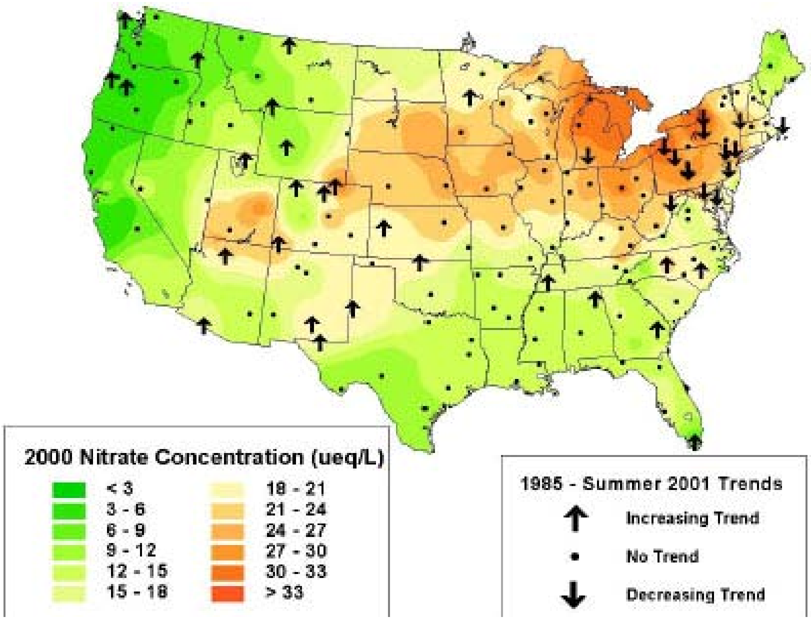


Figure 2. Trends in nitrate concentrations in wet deposition, 1985-2001. Nitrate concentrations are moderate in the Four Corners Region and show either no trend or an increasing trend over time.[2]

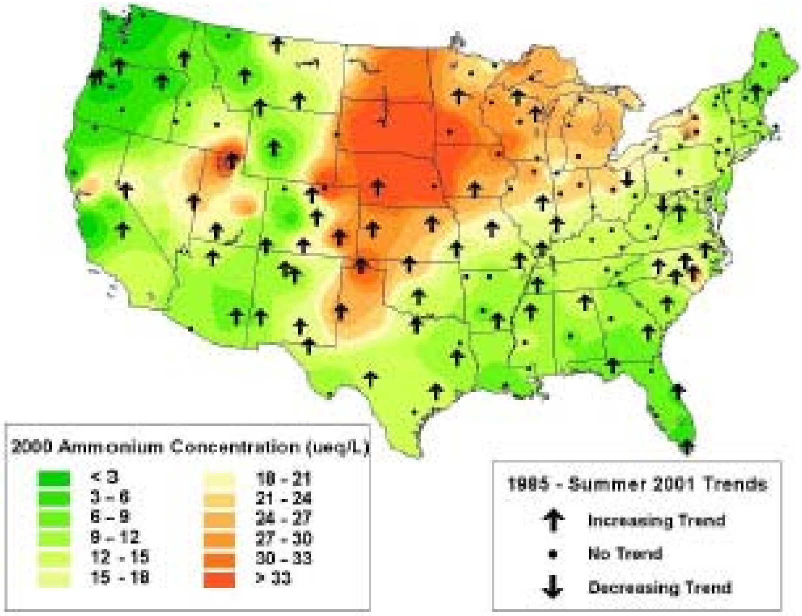


Figure 3. Trends in ammonium concentrations in wet deposition, 1985-2001. Ammonium concentrations are low in the Four Corners Region but show an increasing trend over time.[2]

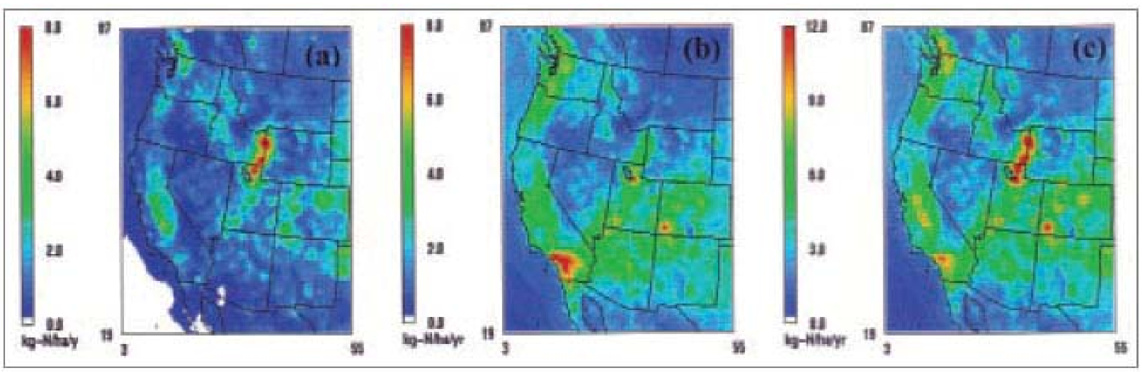
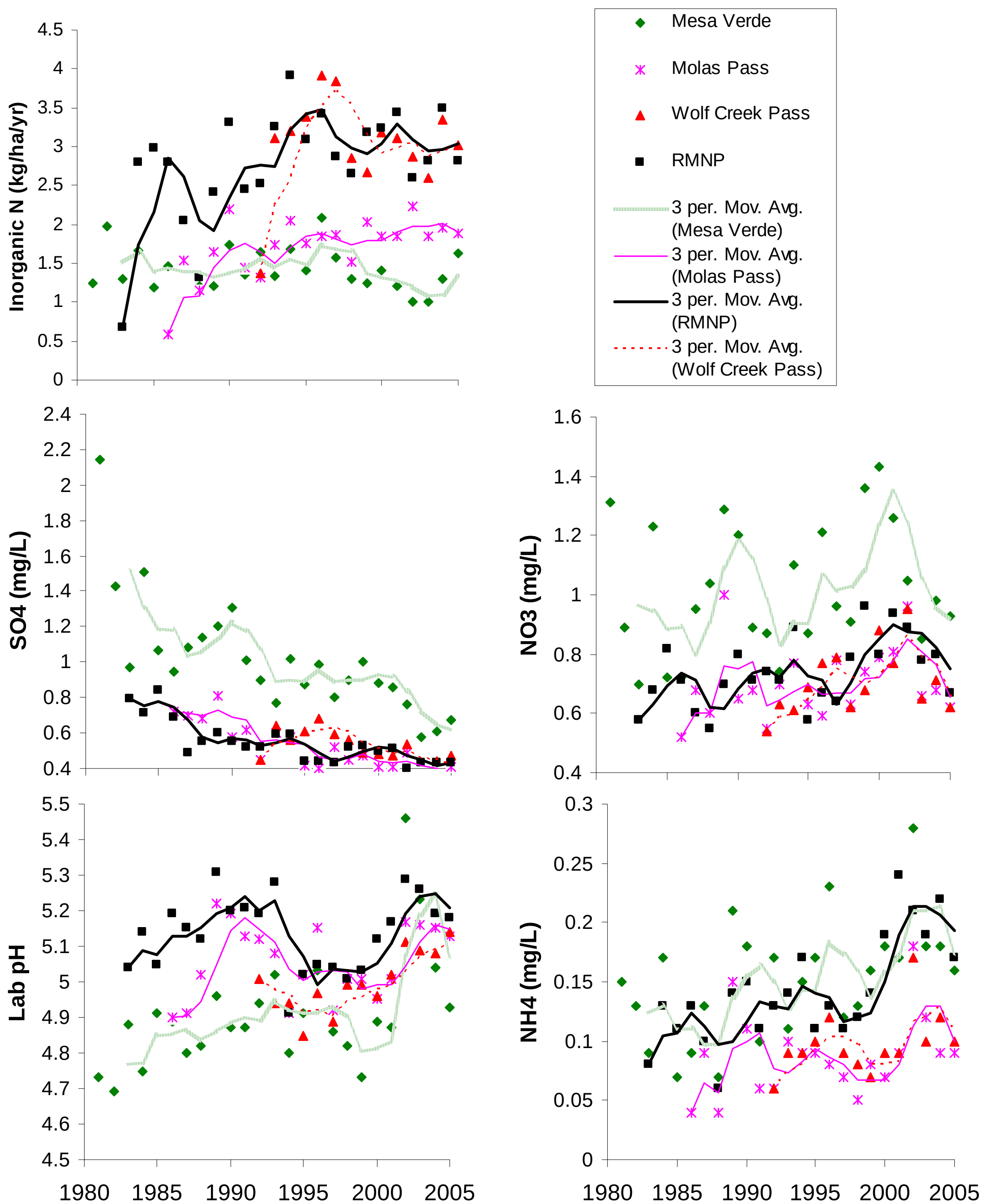


Figure 4. Model-simulated annual nitrogen deposition (kg/ha/yr) in the western United States in 1996 for (a) total wet and dry deposition of N from ammonia and ammonium, (b) total wet and dry deposition of N from nitric oxide, nitrogen dioxide, nitric acid, and nitrate, and (c) total N deposition calculated as the sum of (a) and (b).[13]

Figure 5. Annual averages of total inorganic nitrogen, pH, and sulfate nitrate, and ammonium concentrations in wet deposition from Mesa Verde National Park, Molas Pass, Wolf Creek Pass, and Rocky Mountain National Park (RMNP). Concentrations are precipitation volume-weighted means. Trend lines are 3 period moving averages and are not meant to indicate presence or absence of statistical trends. RMNP is included for comparison as a location where ecological effects of nitrogen deposition are documented.



Additional figures for Mesa Verde National Park based on data from the National Atmospheric Deposition Program:

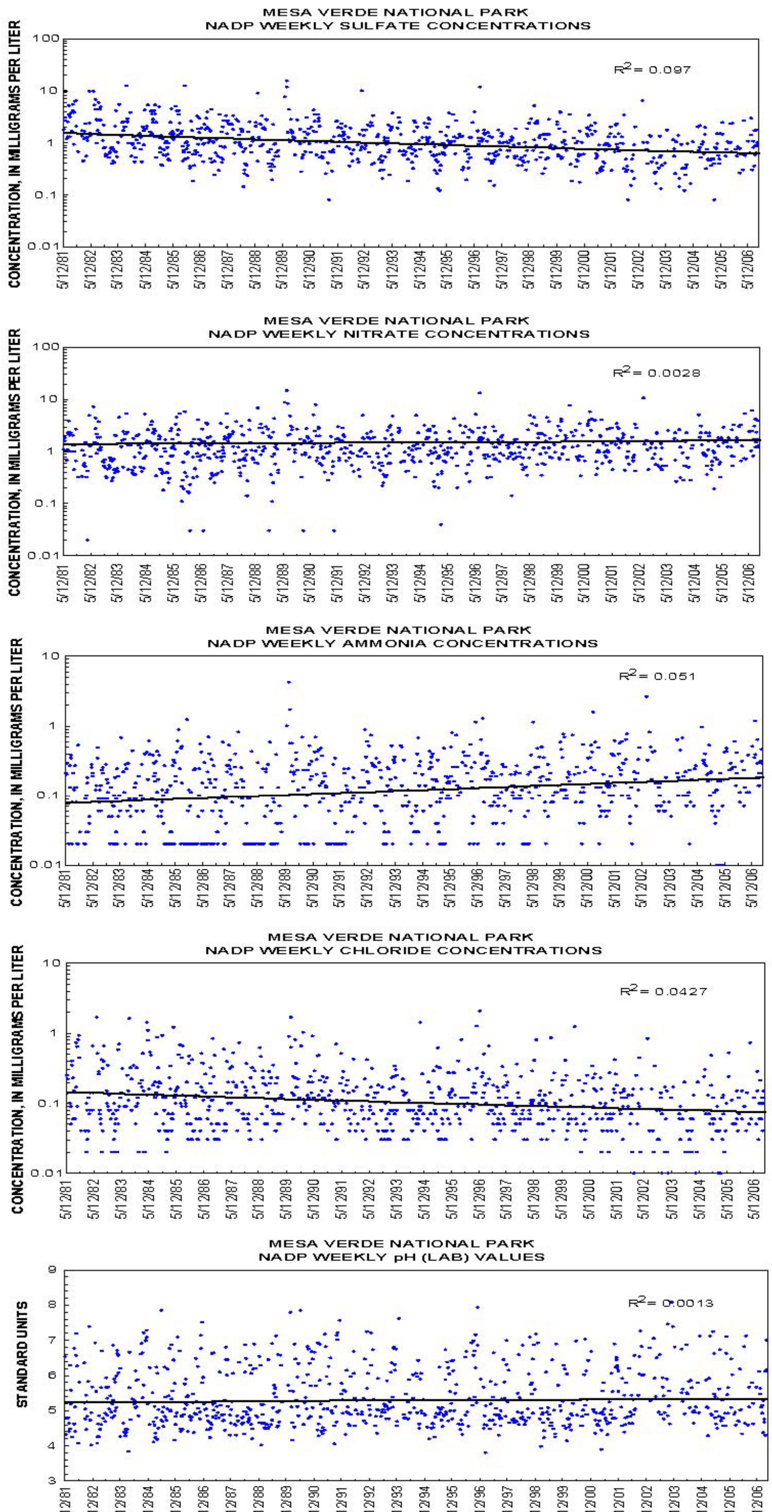


Figure 1. Weekly concentrations of selected constituents in wet deposition at Mesa Verde National Park, 1981-2006. Data are from the National Atmospheric Deposition Program.

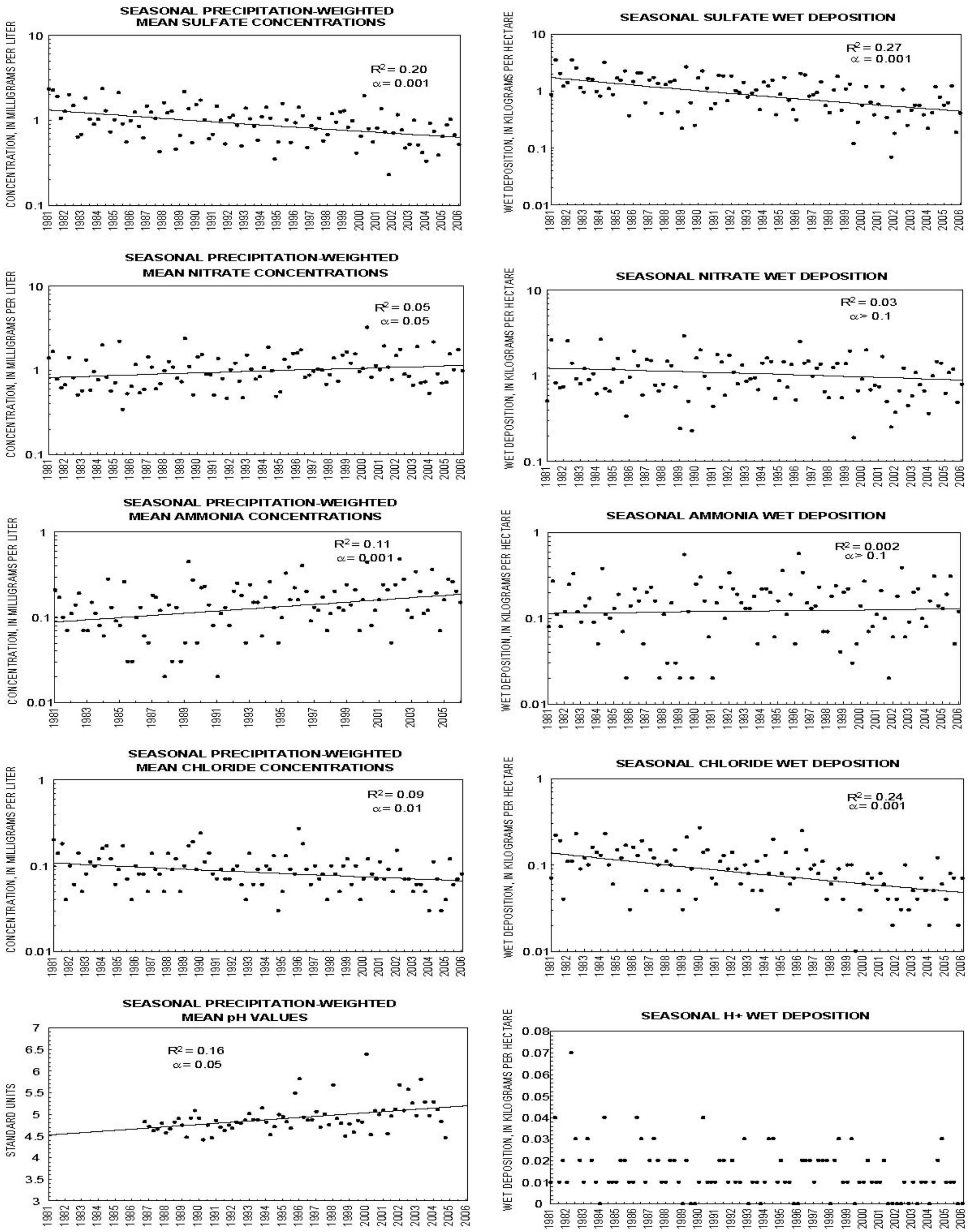


Figure 2. Seasonal concentrations and wet deposition of selected constituents at Mesa Verde National Park, 1981-2006. Data are from the National Atmospheric Deposition Program. Significance (α) from Mann-Kendall trend test.

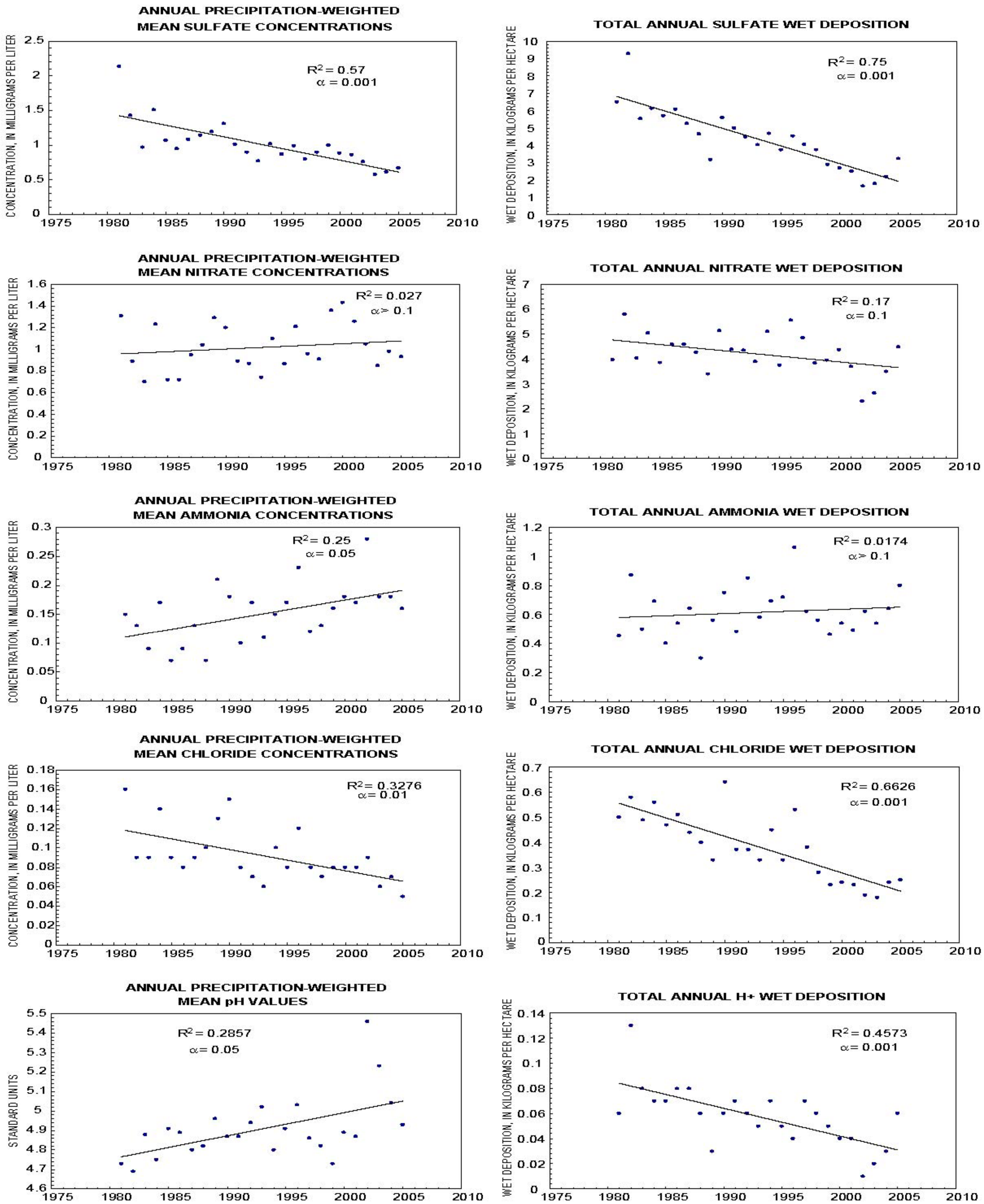


Figure 3. Annual concentrations and wet deposition of selected constituents at Mesa Verde National Park, 1981-2006. Data are from the National Atmospheric Deposition Program. Significance (α) from Mann-Kendall trend test.

Visibility

I. Background

Title 42 U.S.C. §§ 7491 and 7492 of the Clean Air Act established a national policy to study and protect visibility in Federal class I areas. It declares as a national goal "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution."[1] Of several mandatory class I areas Federal areas on the Colorado Plateau, Arches National Park, Canyonlands National Park, the Weminuche Wilderness, and Mesa Verde National Park lie within near or immediate proximity to the Four Corners Region.

Several planning and monitoring authorities have evolved from this statutory requirement, two of which are able to directly address visibility concerns in the Four Corners region. The Interagency Monitoring of Protected Visual Environments (IMPROVE) program was initiated in 1985, and has implemented an extensive long term monitoring program in the National Parks and Wilderness Areas.[2] Additionally, the Western Regional Air Partnership (WRAP) was formed in 1997 as the successor to the Grand Canyon Visibility Transport Commission, and promotes the implementation of recommendations that were made in the previous commission.[3] Specifically, the WRAP partnership is implementing a regional planning process to improve visibility in all western Class I areas "by providing the technical and policy tools needed by states and tribes to implement the federal regional haze rule."[4]

EPA issued the final Regional Haze Rule on April 22, 1999.[5] "The rule requires the states, in coordination with the Environmental Protection Agency, the National Park Service, U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties, to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment."[6] This regulation is also anticipated to have the additional benefits of improving visibility outside of class I areas, as well as ameliorating the health impacts associated with fine particulates (PM 2.5).[7]

II. What affects visibility and how is it monitored?

The interaction between certain gasses, particulate matter, and the light that passes through the atmosphere yields the basic processes through which visibility is affected. Gasses and *aerosols* may scatter or block sunlight through *diffraction, absorption,* and *refraction*. When sunlight encounters gasses and aerosols, it scatters preferentially as a function of the size of the particles that it encounters.[8] The relationship between particulate size and light is extremely important, as it ultimately accounts for changes in color and *haze*. Although the total mass of coarse particles (PM 10) in the atmosphere outnumbers the total mass of fine particles (PM 2.5), the finer particles "are the most responsible for scattering light" because they scatter light more efficiently, and because there are more of them.[9] Consequently, the origin and transport of fine particles (PM 2.5) is of greatest concern when assessing visibility impacts.[10]

In the most general sense, visibility is the effect that various aerosol and lighting conditions have on the appearance of landscape features.[11] While photography is the simplest method used to convey visibility impairment, it is difficult to garner quantitative information from photographs, digital pictures, or slides. Because some direct measurement of the atmosphere's optical qualities is desired, most visibility programs include a measure of either atmospheric *extinction* or *scattering*.

> The *scattering coefficient* is a measure of the ability of particles to scatter photons out of a beam of light, while the *absorption coefficient* is a measure of how many photons are absorbed. Each parameter is expressed as a number proportional to the amount of photons scattered or absorbed per distance. The sum of scattering and absorption is referred to as *extinction* or attenuation.[12] (Emphasis added.)

Extinction is measured by devices such as the *transmissometer* and *nephelometer*. Most monitoring programs use combinations of these devices to measure extinction and scattering. Extinction is usually described in terms of *inverse megameters* (Mm^{-1}), and is proportional to the amount of light that is lost as it travels over a million meters.[13] *Deciviews* is another measurement of extinction, but which is scaled in a way that it is perceptually correct. "For example, a one deciview change on a 20 deciview day will be perceived to be the same as on a 5 deciview day."[14] Because deciviews are *scaled* so that they may describe *changes* in visibility, they must be distinguished from extinction as it can otherwise be described in inverse megameters and *visual range*.

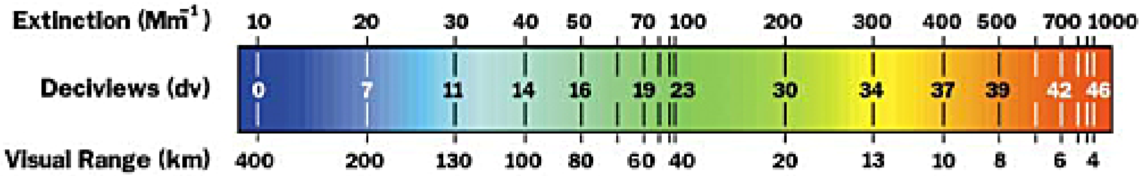


Fig. A Comparison of extinction (Mm^{-1}), deciview (dv), and visual range (km).
(Source: Malm, William C. Introduction to Visibility.)

In addition to the measurements of scattering and extinction, it is also helpful to know what materials in the air are contributing to visibility impairment. *Particle measurements* are normally made in conjunction with optical measurements "to help infer the cause of visibility impairment, and to estimate the source of visibility reducing aerosols."[15] The size and composition of particles are the most commonly identified characteristics that are used in visibility monitoring programs. Additionally, "particles between 0.1 to 1.0 microns are most effective on a per mass basis in reducing visibility and tend to be associated with man-made emissions."[16] These fine particles are usually grouped under the category PM 2.5, which refers to particles that are less than 2.5 microns large. (As discussed earlier, PM 2.5 particles are in general the most effective in scattering light due to their small size.) "The IMPROVE fine particle modules employ a cyclone at the air inlet which spins the air within a chamber. Fine particles are lifted into the air stream where they are siphoned off and collected on a filter substrate for alter analysis."[17] Once the size of particles has been measured, they are speciated by composition. The identification of sulfates, nitrates, organic material, elemental carbon (soot) and soil "helps determine the chemical-optical characteristics and the ability of the particle to absorb water (RH effects) and is important to separate out the origin of the aerosol."[18]

> A visibility impairment value is calculated for each sample day. To get a valid measurement, all four modules must collect valid samples. The regional haze regulations use the average visibility values for the clearest days and the worst days. The worst days are defined as those with the upper 20% of impairment values for the year, and the clearest days as the lowest 20%. The goal is to reduce the impairment of the worst days and to maintain or reduce it on the clear days.[19]

For data to be considered under the regional haze regulations, it must meet the minimum criteria for the number of daily samples needed in a valid year: 1.) 75% of the possible samples for the year must be complete; 2.) 50% of the possible samples for each quarter must be complete; 3.) No more than 10 consecutive sampling periods may be missing.[20]

As noted above, the filter analysis provides the concentrations and composition of atmospheric particles. The *source contribution* to visibility impairment can be indicated from the analysis of trace elements:

vanadium/nickel	»	petroleum-based facilities, autos
arsenic	»	copper smelters
selenium	»	power plants
crustal elements	»	soil dust (local, Saharan, Asian)
potassium (nonsoil)	»	forest fires[21]

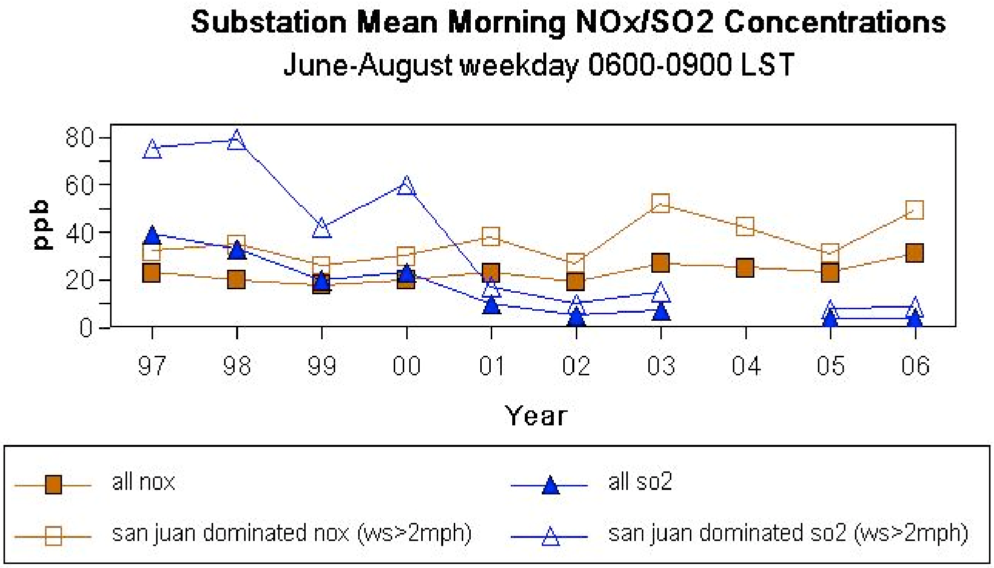
III. Visibility in the Four Corners

Currently, there are four sites within the Four Corners region that monitor visibility: Mesa Verde National Park, the Weminuche Wilderness (near Purgatory,) the Shamrock Mine (southeast La Plata County,) and Canyonlands National Park. Of these four sites, only the Forest Service monitoring station at the Shamrock Mine records images, and is included in IMPROVE's optical and scene monitoring network. Additionally, because the Canyonlands site lies on the margin of the Four Corners Region, and it is also located at a comparatively lower elevation north of the Blue Mountains, it may not serve as the best indicator of visibility trends in the Four Corners proper.

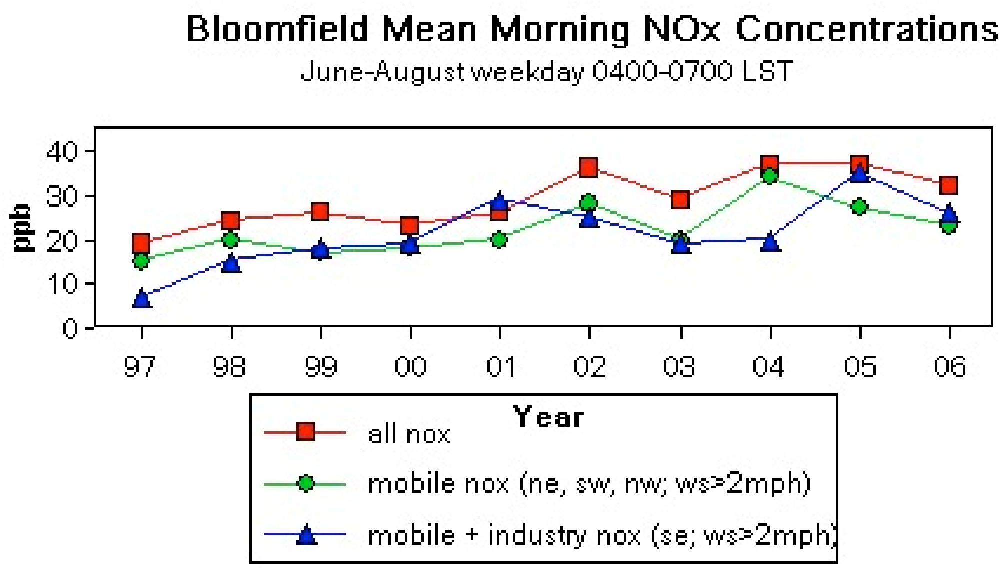
Preliminary analysis of deciview trends at Mesa Verde, and also of visibility-impairing gasses and particulates as monitored at other sites, does not reveal a clear trend of how visibility might be changing in the Four Corners. This appraisal is not concomitant with the observations of many area residents. It may be indicative of monitoring gaps that exist in the Four Corners, and it has led to the perception by members of the Task Force Monitoring Group that a comprehensive, detailed analysis of all available data regarding visibility is greatly needed.

Despite that ambiguity, however, there are a few details worth noting. In September of 2005, the Interim Emissions Workgroup of the Four Corners Air Quality Task Force recommended that an ambient monitoring program for gaseous ammonia be initiated in the Four Corners region. The purpose of this program is to set a current baseline of ambient gaseous ammonia concentrations in the Four Corners, that can be compared to monitored values in approximately 3-5 years after the implementation of NOx controls (e.g. NSCR) on oil and gas equipment. The use of NSCR may increase ammonia emissions in the area, but these emissions have not been quantified and may or may not significantly affect visibility. Ammonia at high enough concentrations can contribute to worsening visibility by forming PM 2.5 ammonium nitrates and ammonium sulfates.

Additionally, the implementation of new SO_2 controls at the San Juan Generating Station in 1999 has successfully reduced SO_2 emissions in the area. Because of the high impact that SO_2 can have upon visibility, that reduction has likely made a positive impact upon visibility conditions in the Four Corners. However, changes in monitoring conditions at San Juan Substation have not been limited to a decrease in SO_2. Concurrently, it appears that NOx concentrations have risen, and now dominate over SO_2:



For the same time period, similar increases in NOx have been observed in Bloomfield, and it appears that NOx may be slowly increasing as a regional trend:

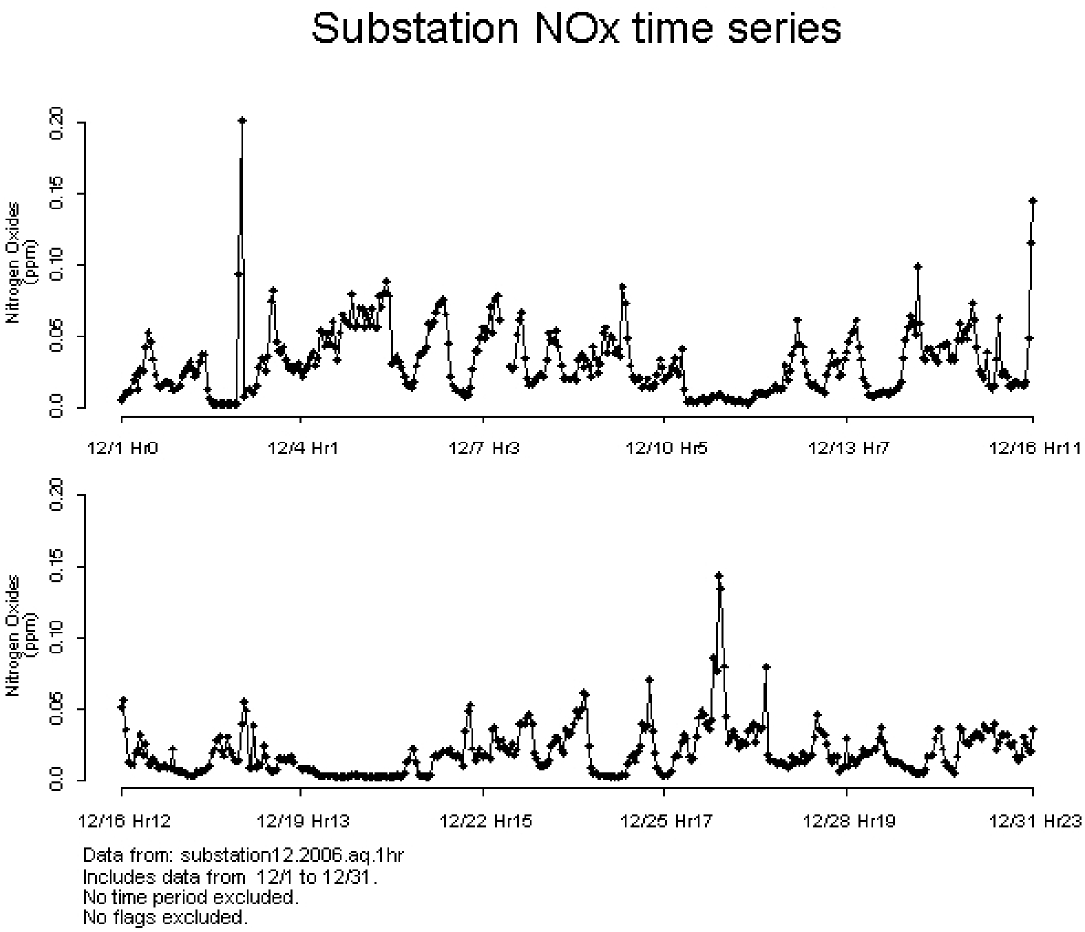


Many citizen's accounts on deteriorating visibility in the Four Corners have centered upon wintertime episodes. The ways in which seasonal differences may impact visibility is very important. In the summertime, the "confining layer" of the atmosphere, which generally holds pollutants below a certain altitude, is much higher. Additionally, the extra heat associated with warmer seasons allows the atmosphere to move and mix more readily. The result is that, in the summertime, visibility-impairing pollutants can mix more easily, and dilute within in a greater vertical distance. Conversely, in the wintertime, that confining layer is usually much lower (thus the prevalence of wintertime inversions.) In colder seasons, the atmosphere does not move or mix as easily. Therefore, generally, wintertime pollutants are held closer to the ground level, and they cannot readily dilute into the upper atmosphere. Given this effect, the same level of regional emissions year-round will likely be more noticeable in the winter as *layered haze*. The addition of rising emissions levels will compound this effect in the wintertime.

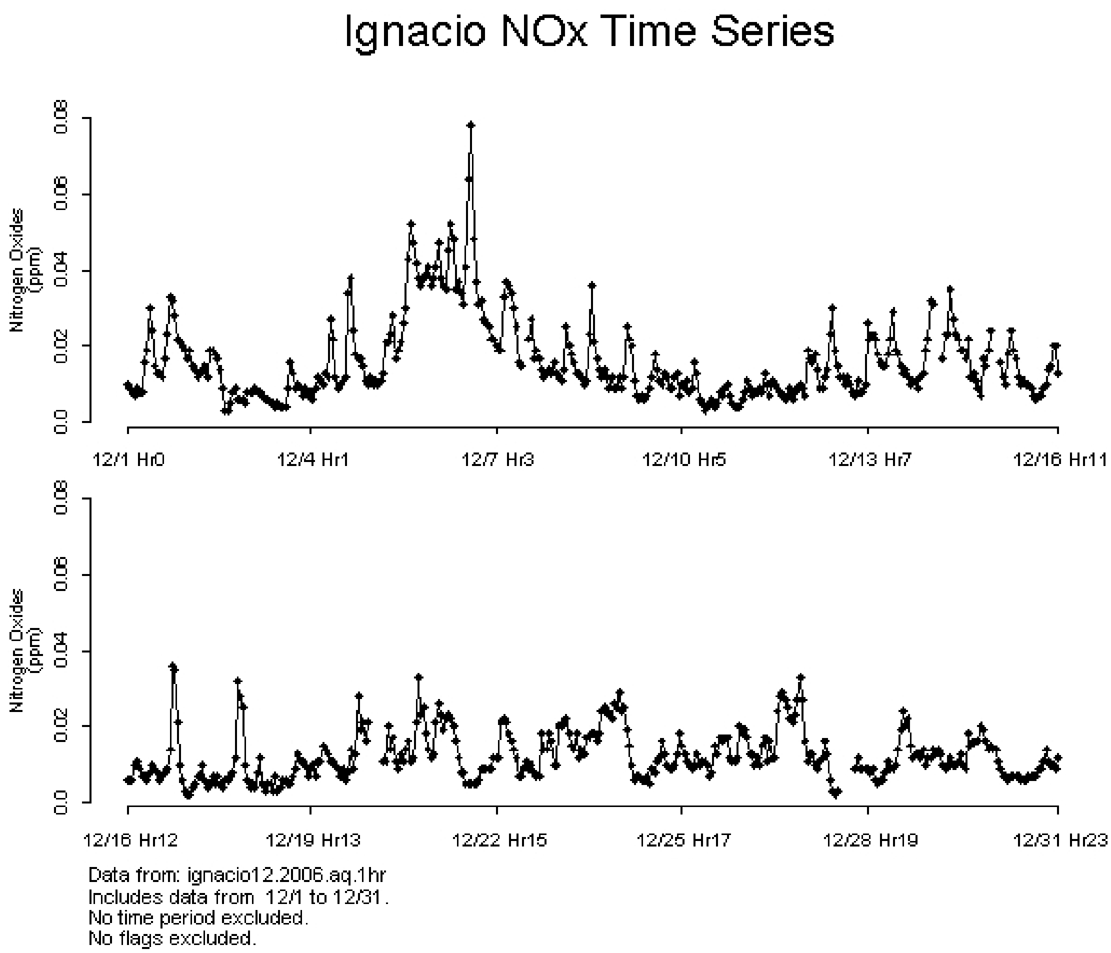
Wintertime haze near Kline, Colorado. 12/05/2006. *See also*: A Resident's Observation of Visibility, this section.

Excellent visibility, photo taken one mile west of previous photo. 10/21/2006.

The considerations outlined above reasonably lead to the hypothesis that citizens' accounts of deteriorating visibility, as they are specific to wintertime episodes, may be partially caused by increasing NOx emissions. For an initial test of this hypothesis, we may review what NOx concentrations existed in the region at the time of the 12/05/2006 photograph:

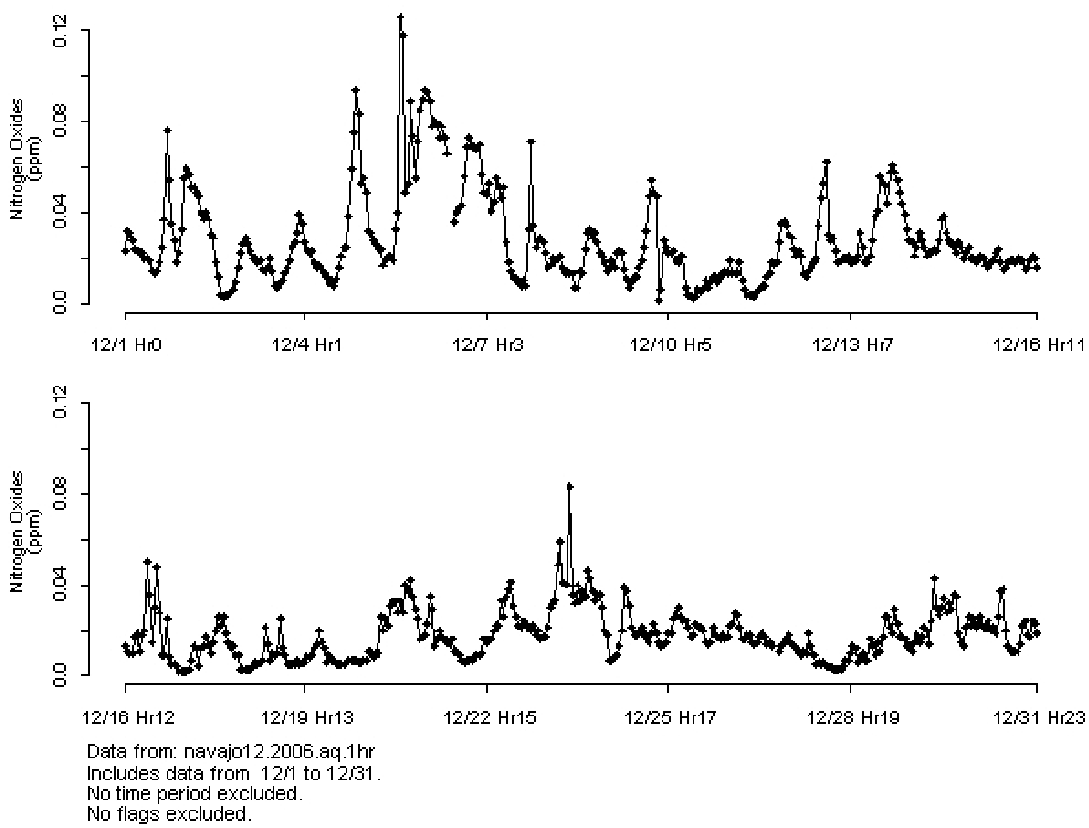


Elevated NOx concentrations existed at the San Juan Substation, with the most pronounced event occurring approximately 48 hours before the 12/05/2006 photograph.

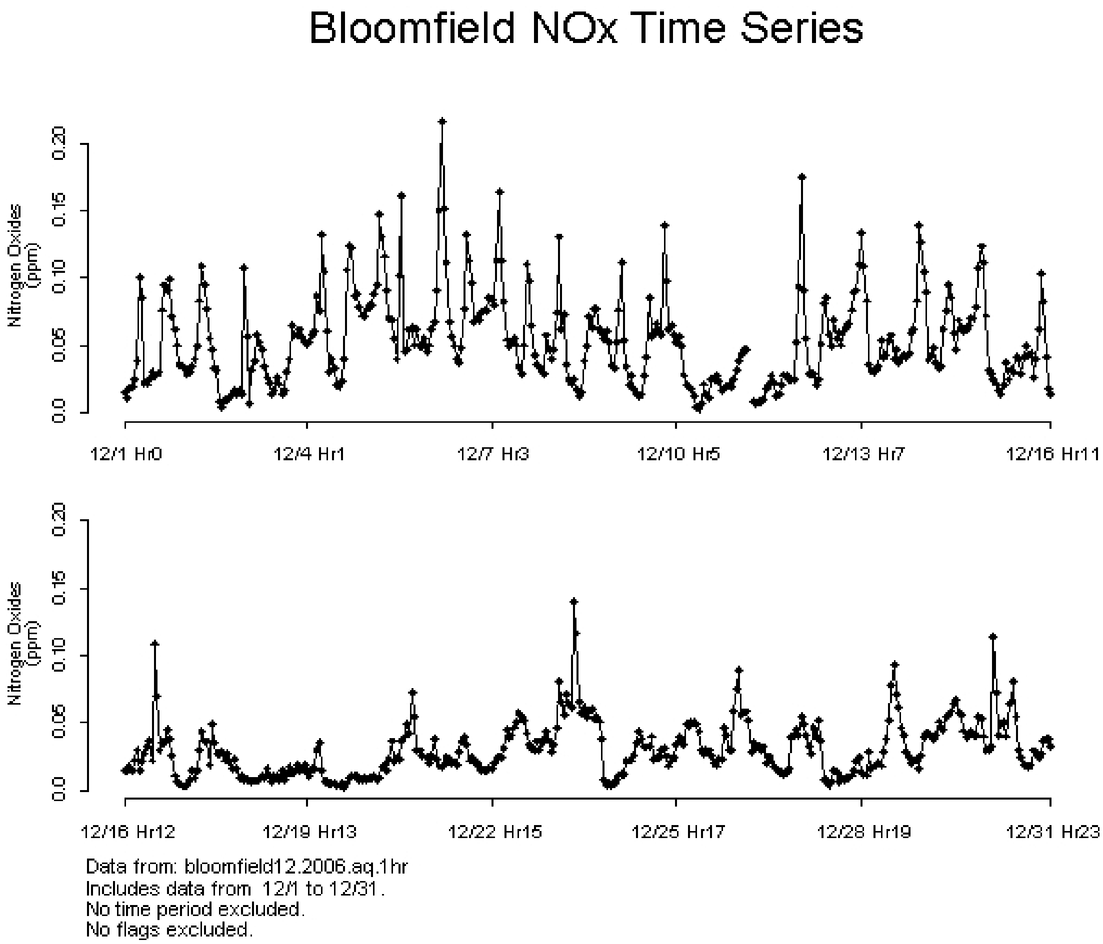


Elevated NOx concentrations existed at the Ignacio monitoring site approximately 24 hours after the 12/05/2006 photograph.

navajo lake NOx time series



Elevated NOx concentrations existed at the Navajo Lake monitoring site, with the most pronounced concentrations occurring on 12/05/2006.



Elevated NOx concentrations existed at the Bloomfield monitoring site, with the most pronounced concentrations occurring within 24 hours of the 12/05/2006 photograph.

It appears that NOx concentrations were a contributing factor behind the visibility impairment episode documented in the 12/05/2006 photograph. These preliminary observations raise a number of additional considerations. First, there exists a great value in the photographic documentation of visibility. These elevated NOx concentrations might not have been considered if one were to only examine particulate data over a given time period. *Visual observations*, although subjective, provide the first clue that will lead the inquisitor to examine specific episodes and time periods. The contemplation of criteria such as color, location, and the *expanse* of impairment episodes considers the *regional nature* of visibility impairment in a way that no site-specific particulate measurement can do. In a sense, visual accounts and photographic documentation is a *top-down* approach that reveals what data needs to be specifically considered, and where additional monitoring would be useful.

Second, in the case of indeterminate deciview trends at Mesa Verde, the preceding discussion on photographic documentation obliges us to consider the monitoring site's location. Mesa Verde is situated upon the uppermost reaches of the *Four Corners Platform*. This geologic plateau rises above the valleys and basins of the Four Corners region, and typifies the area's rugged and varied topography. The monitoring site at Mesa Verde is located at roughly 7,200 feet above sea level, while most emissions in the region occur in the San Juan Basin to the south, at roughly 5,000 feet. (Likewise, most other emissions in the region are related to human activity, and occur in the other multiple valleys and basins that are topographically separated from the Park.) Given the occurrence of wintertime inversions and a lower confining atmospheric layer, it is entirely possible that what is observed as severe visibility impairment will not be recorded at Mesa Verde, because the monitoring site will be *above the confining layer*. The absence of photographic documentation coexistent with particulate measurements in the Park causes that data to be extrapolated from air quality within the Park itself, and it will not effectively consider what an observer might actually see as she looks across the region from that location.

It is reasonable to assume that (wintertime) visibility impairment in the Four Corners is exacerbated by the area's rugged topography, which often confines visibility impairment to within the region's numerous basins and deep valleys. Additionally, that visibility monitoring in the Four Corners which is reliant on particulate measurements is located at higher elevations, and is not likely to record events related to low confining layers and atmospheric inversions. (I.e. Mesa Verde and the Weminuche.) These locations are, however, great *vantage points* from which visibility may be observed, but they forgo this opportunity because they do not include photographic documentation. Furthermore, Canyonlands National Park is not a good location to observe visibility as it relates to the Four Corners, because it is too distant from the region. (Both the path of emissions transport and line of sight from the Four Corners to Canyonlands is blocked by the higher elevations surrounding the Blue Mountains and Bear's Ears.) That leaves only one site—the Shamrock Mine—from which visibility in the Four Corners Region can be satisfactorily observed and documented year-round.

IV. Suggestions for Future Monitoring Work

Air quality monitoring is a rather expensive operation, and so resources that might provide for saturation studies or additional permanent monitoring should be allocated in consideration of monitoring goals as a whole. However, it is still reasonable to advocate some additional monitoring of visibility, as most of the following suggestions could be incorporated into existing sites.

Last, most visibility monitoring in the Four Corners is unevenly distributed (or restricted) to Class I areas. Therefore, visibility monitoring within these Class I areas is not conducive of a regional trends assessment, especially because they are based on a very few site-specific particulate measurements. Furthermore, the regional monitoring of visibility is desirable, because it can assist with the protection of Class I areas and EPA's regional haze rule. Additionally, regional monitoring of visibility will better address the value that citizens place upon the vistas that exist outside of Class I areas, while recognizing how visibility impacts citizens' perceptions of air quality as a whole. In sum, it is highly desirable that we consider how visibility monitoring in the Four Corners region can be perfected, with the intent of making a *strong regional assessment*.

1. It is suggested that the monitoring sites at Mesa Verde and in the Weminuche resume photographic documentation.

2. Many previous studies of visibility in the Four Corners relate only to site-specific locations, and often conflict in their findings. A comprehensive assessment of historical data is needed, in order to determine regional trends or changes in visibility. Currently, it is very difficult not only to establish regional trend analyses, but also to compare them to historical baseline data.

3. Additional visibility monitoring should be established at locations in the region other than what exists in Class I areas. This additional monitoring:

1. could be incorporated into existing monitoring sites;
2. should include photographic documentation;
3. and, it should specifically consider how topographical variations impact the measurement of visibility.

4. The apparent contribution of NOx emissions to wintertime visibility impairment is recommended for further study.

V. Works Cited:

1. 42 U.S.C. § 7491 (a)(1).
2. http://vista.cira.colostate.edu/improve/ (access date 4/05/2007).
3. http://www.wrapair.org/facts/index.html (access date 4/05/2007).
4. Id.
5. http://vista.cira.colostate.edu/improve/Overview/hazeRegsOverview_files/v3_document.htm (access date 4/05/2007). *See also* http://www.epa.gov/air/visibility/program.html.

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7. http://vista.cira.colostate.edu/improve/Overview/hazeRegsOverview_files/v3_document.htm
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9. Malm, William C. 1999. Introduction to Visibility. Cooperative Institute for Research in the Atmosphere (CIRA). Fort Collins, Colorado. P. 8.
10. Id. at 9.
11. Id.
12. Id. at 27.
13. Id.
14. Id. at 35.
15. Id.
16. Id. at 28.
17. Id. at 28, 29.
18. IMPROVE 2007 Calendar.
19. Malm at 29.
20. IMPROVE 2007 Calendar.
21. Id.
22. Id.

The complete photographic record prepared by Erich Fowler is available by contacting Mark Jones at mark.jones@state.nm.us. This is a very large file (over 100 MB).

Mitigation Option: Interim Emissions Recommendations for Ammonia Monitoring

I. Description of the mitigation option

The following mitigation option paper is one of three that were written based on interim recommendations that were developed prior to the convening of the Four Corners Air Quality Task Force. Since the Task Force's work would take 18-24 months to finalize, and during this time oil and gas development could occur at a rapid pace, an Interim Emissions Workgroup made up of state and federal air quality representatives was formed to develop recommendations for emissions control options associated with oil and gas production and transportation. The Task Force includes these recommendations as part of its comprehensive list of mitigation options.

Implement an ambient monitoring program for ammonia

C. Assess importance of ammonia to visibility
D. Visibility modeling would be more accurate if ammonia data were available
E. Ammonia emission impacts from NSCR can be better evaluated
F. US EPA Region 6 will assist with this effort

Evaluate data on ammonia emissions from engines less than 300 HP equipped with NSCR

- Testing should be done in the field
- Funding would need to be secured
- A contractor to make measurements would need to be found

II. Description of how to implement

The ambient monitoring program for ammonia would be conducted under the auspices of EPA Region 6. The appropriate agencies to implement this are EPA Region 6 and the New Mexico and Colorado departments of environmental quality. Collecting data on ammonia emissions from engines less than 300 HP would be voluntary and funding would need to be secured.

III. Feasibility of the Option

The technical feasibility of the ambient monitoring has already demonstrated. Specifically, the technical feasibility of measuring ammonia emissions from engines with NSCR has been demonstrated as part of a research project initially started by Colorado State University. However the exact methodology is not yet chosen. The environmental feasibility is negligible since only samples are collected. The economic feasibility depends on finding someone to pay for the sampling program

IV. Background data and assumptions used

The ambient monitoring would be conducted either by collecting samples or by real time analysis depending on equipment selected. Approximate measurements can be made using sampling tubes similar to Draeger tubes. The assumption is that a baseline ammonia level should be established and that potential increases may be observed because of the use of large numbers of rich burn engines with NSCR catalysts.

This methodology is already being tested in the Colorado State University research project.

V. Any uncertainty associated with the option

The cost of the ambient monitoring program is not well established because the monitoring technology is not fully specified. Therefore, there is some uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

To be determined.

VII. Cross-over issues to the other source groups

This mitigation option would cross over to the Oil and Gas work group.

RESOLUTIONS

Introduction

In January, 2005 the Cortez/Montezuma League of Women Voters Air Quality Committee began its study of air quality issues in Montezuma County. It became evident that to study air quality we needed facts. To gain facts we needed monitoring. A committee was formed consisting of the following League of Women Voters members: Sylvia Olivia-air quality consultant, Judy Schuenemeyer-lawyer, Eric Janes-water quality expert, Jack Schuenemeyer-statistician, Mary Lou Asbury-spokesperson. The committee met frequently and came up with a plan of action.

We invited Mark Larson, our state representative and Jim Isgar, our state senator, to a League of Women Voters meeting. Sylvia showed the plume model (a computer model of the plume movement from the areas existing power plants and the proposed 2 new power plants). We discussed the need for monitoring in the Montezuma Valley. Both agreed to take our concerns to the Colorado Legislature and the Colorado Health Department. The ground work was laid.

The committee then met in Durango with the Congressional staff of Senator Ken Salazar and Representative John Salazar. To show governmental and community support for air monitoring we decided we needed to take resolutions to the Montezuma County Commissioners, Cortez City Council, and Mancos and Dolores Town Boards. A power point presentation with facts on ozone and mercury was decided upon.

The committee met over a period of 2-3 months to put the finishing touches on the power point, commentary and resolutions. Presentations were scheduled starting in June,2005.

Sylvia Olivia, Eric Janes, Judy and Jack Scheunemeyer and Mary Lou Asbury were in attendance for all presentations. Questions were answered to the satisfaction of all. Resolutions were signed in support of getting air monitoring, data collection and analysis from the EPA, BLM-CO, BLM-NM, and USGS. These have been mailed to all interested parties including all the Colorado Congressional Delegation and to our state representative and senator. The need was recognized, but the funding has been problematic.

The committee has continued to do presentations to various groups to gain support for the need for air monitoring in the Montezuma Valley. The need becomes more critical as final plans are being made to construct a new power plant. Also, more coal bed methane wells are proposed in the San Juan Basin and throughout the Four Corners Region.

There are many health issues and lifestyle concerns which require an air quality monitoring system. The League of Women Voters resolutions help show concern from representative government. The resolutions follow from the Montezuma County Commissioners, Cortez City Council, Mancos Town Board and Dolores Town Board.

City of Cortez
Resolution No. 17, Series 2005
United States Environmental Protection Agency

Whereas, the City Council of the City of Cortez, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the City, and

Whereas, concerns are being raised by City residents about the possible effects on the City environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico, and

Whereas, Sithe Global Power, Inc. of Houston Texas and the Dine Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant, and

Whereas, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County, and

Whereas, mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children, and

Whereas, the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park, and

Whereas, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury, and

Whereas, City residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher, and

Whereas, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the City of Cortez, and

Whereas, additional monitoring sites are needed in the County to measure current levels of air pollution in order to assess the additional impact on air quality of the proposed power plant.

Now Therefore Be It Resolved by the Cortez City Council,

That, the Council finds that additional air quality monitoring sites are needed elsewhere in Montezuma County to adequately assess the impact of air pollution from sources outside the State of Colorado on the health of City residents, and

Further that, the Council requests that the Regional Administrator of the United States Environmental Protection Agency, Denver seek funding in its Fiscal Year 2006 and 2007 budgets for air and water monitoring equipment to be placed at sites through Montezuma County. We ask that funding be directed to an entity in southwestern Colorado mutually agreeable to the Montezuma County Commissioners, the EPA, and other parties as they shall deem appropriate to query.

MOVED, SECONDED AND ADOPTED THIS 14th DAY OF JUNE 2005.

Orly Lucero, Mayor

ATTEST:

Linda L. Smith, City Clerk

City of Cortez
Resolution No. 14, Series 2005
USGS Colorado Water Science

Whereas, the City Council of the City of Cortez, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the City, and

Whereas, concerns are being raised by City residents about the possible effects on the City environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico, and

Whereas, Sithe Global Power, Inc. of Houston Texas and the Dine Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant, and

Whereas, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County, and

Whereas, mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children, and

Whereas, the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park, and

Whereas, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury, and

Whereas, City residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher, and

Whereas, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the City of Cortez, and

Whereas, additional water monitoring sites on a bi-weekly to monthly frequency are needed on the Dolores River and Mancos River systems in the County to measure levels of mercury in order to assess the ultimate fate of mercury from the proposed power plant and existing power plants.

Now Therefore Be It Resolved by the Cortez City Council,

That, the Council finds that additional water monitoring sites for mercury are needed on the Dolores and Mancos River systems to adequately assess the ultimate fate of mercury from air pollution sources outside the State of Colorado on the health of City residents, and

Further that, the Council requests that the USGS Colorado Water Science Director in Denver seek funding in the Fiscal Year 2006-2007 budgets for increasing the USGS Colorado ability to monitor mercury in water in the Dolores and Mancos River systems.

MOVED, SECONDED AND ADOPTED THIS 14th DAY OF JUNE 2005.

Orly Lucero, Mayor

ATTEST:

Linda L. Smith, City Clerk

RESOLUTION # 230
TOWN OF DOLORES
SUPPORT FOR AIR AND WATER MONITORING FUNDING THROUGH
COLORADO BUREAU OF LAND MANAGEMENT

WHEREAS, The Town of Dolores Board of Trustees, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the Town; and

WHEREAS, concerns are being raised by Town residents about the possible effects on the Town environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico; and

WHEREAS, Sithe Global Power, Inc. of Houston, Texas and the Dine' Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant; and

WHEREAS, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County; and

WHEREAS, mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children; and

WHEREAS, the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park; and

WHEREAS, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury; and

WHEREAS, County residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher; and

WHEREAS, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the Town of Dolores; and

WHEREAS, additional monitoring sites are needed in the County to measure current levels of ozone, mercury in rain and snow, and Dolores and Mancos River mercury concentrations in order to assess the additional impact on air quality of the proposed power plant, and

NOW, THEREFORE BE IT RESOLVED, that the Town Board, Town of Dolores finds that additional air and water monitoring sites are needed elsewhere in Montezuma County to adequately assess the impact of air pollution from sources outside the State of Colorado on the health of Town residents; and

BE IT FURTHER RESOLVED, that the Town Board, Town of Dolores requests that the Colorado Bureau of Land Management see funding in its Fiscal Year 2006 and 2007 budgets for air and water monitoring equipment to be placed at sites throughout Montezuma County. The Town Board asks that funding be directed to an entity in southwestern Colorado mutually agreeable to the Dolores Town Board, the Colorado Bureau of Land Management, and other parties as they shall deem appropriate to query.

Done this 12th day of September, 2005

Marianne Mate, Mayor
Town Board of Trustees

ATTEST:

Ronda Lancaster

Ronda Lancaster,
Town Clerk/Administrator

RESOLUTION NO. 2006–40

A RESOLUTION OF THE BOARD OF COUNTY COMMISSIONERS OF LA PLATA COUNTY, COLORADO, FOR REGION IX AIR DIVISION OF THE ENVIRONMENTAL PROTECTION AGENCY CONCERNING THE CLEAN AIR ACT PERMIT FOR THE DESERT ROCK POWER PLANT

WHEREAS, the United States Environmental Protection Agency (US EPA) Region IX has proposed a Clean Air Act permit that would authorize construction of a 1500-megawatt coal-fired power plant on the Navajo Nation; and

WHEREAS, the permit regulates the reduction of particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds, and lead emissions with the Best Available Control Technology, and must comply with health-based National Ambient Air Quality Standards; and

WHEREAS, Chapter 6, page 6.1 of the La Plata County Comprehensive Plan - Environmental Resources states "La Plata County's natural resources are a valuable community asset. Ensuring their preservation and appropriate use is important to both the natural beauty and economy of La Plata County;" and

WHEREAS, "Environmental Quality and unique natural features are what defines the character of La Plata County and ensuring their continued viability and health is important;" and

WHEREAS, the comment period for this clean air quality permit closes before the draft Environmental Impact Statement is released to the public resulting in an incomplete understanding of the cumulative impacts of the plant; and

WHEREAS, mercury is a significant and demonstrable problem resulting in a degradation in the quality of life for La Plata County citizens, failure to include the monitoring of mercury, a byproduct of all coal burning power plants would be negligent to the citizens;

NOW THEREFORE, BE IT RESOLVED BY THE BOARD OF COUNTY COMMISSIONERS OF LA PLATA COUNTY, COLORADO, AS FOLLOWS:

1. That the La Plata County Board of County Commissioners hereby requests that the Environmental Protection Agency Region IX Air Division deny the Clean Air Act Permit for Desert Rock Power Plant so the full Environmental Impact Statement for this project is completed to allow the citizens of La Plata County an understanding of the full cumulative impacts from the proposed plant.

2. That the La Plata County Board of County Commissioners hereby requests that all available technology be utilized to reduce the amount of pollutants, including mercury, emitted by this plant.

DONE AND ADOPTED IN DURANGO, LA PLATA COUNTY, COLORADO, this 24th day of October, 2006.

BOARD OF COUNTY COMMISSIONERS
LA PLATA COUNTY, COLORADO

ATTEST

____
Wallace "Wally" White, Chair

____
Clerk to the Board

____
Robert A. Lieb, Vice Chair

____
Sheryl D. Ayers, Commissioner

DISTRIBUTION: United States Environmental Protection Agency Region IX
Attn: Robert Baker
75 Hawthorne Street
San Francisco, CA 94105
desertrockairpermit@epa.gov

Resolution (BLM-NM)

Whereas the Board of Trustees, Town of Mancos, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the Town, and

Whereas concerns are being raised by Town residents about the possible effects on the Town environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico, and

Whereas Sithe Global Power, Inc. of Houston Texas and the Dine Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant, and

Whereas the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County, and

Whereas mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children, and

Whereas the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park, and

Whereas State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury, and

Whereas County residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher, and

Whereas Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the Town of Mancos, and

Whereas additional monitoring sites are needed in the County to measure current levels of ozone, mercury in rain and snow, and Dolores and Mancos River mercury concentrations in order to assess the additional impact on air quality of the proposed power plant, Now Therefore

Be It Resolved, that the Board of Trustees, Town of Mancos finds that additional air and water monitoring sites are needed elsewhere in Montezuma County to adequately assess the impact of air pollution from sources outside the State of Colorado on the health of Town residents, and

Be It Further Resolved, that the Board of Trustees, Town of Mancos requests that the Bureau of Land Management New Mexico State Director, Santa Fe seek funding in the Fiscal Year 2006-2007 budgets for air quality monitoring equipment for ozone to be placed at appropriate sites in Montezuma County. We ask that funding be directed to an entity in southwestern Colorado mutually agreeable to the Board of Trustees, the BLM New Mexico and Colorado State Directors, and to other parties as they shall deem appropriate.

APPROVED THIS 22 DAY of June, 2005

Greg Rath

Greg Rath, Mayor

Michele Black

Michele Black, Mayor Pro-Tem

Perry Lewis

Herman J. Muniz

Herman Muniz

Nick Baumgartner

Nick Baumgartner

Ray Martinez

Ray Martinez

Nicki Elmore

Nicki Elmore

THE BOARD OF COUNTY COMMISSIONERS
OF THE COUNTY OF MONTEZUMA
STATE OF COLORADO

At a regular meeting of the Board of County Commissioners of Montezuma County, Colorado, duly convened and held the 13th day of June, 2005, with the following persons in attendance:

Commissioners:	Dewayne Findley, Gerald Koppenhafer, and Larrie Rule
Commissioners Absent:	
County Administrator:	Thomas J. Weaver
County Attorney:	Bob Slough
Clerk and Recorder:	Carol Tullis

the following proceedings, among others, were taken:

Resolution # 5-2005

Resolution (EPA)

WHEREAS, the Commissioners of Montezuma County Colorado are interested in a healthy environment, clean air and water for citizens of Montezuma County; and

WHEREAS, concerns are being raised by Montezuma County residents about the possible effects on air quality and water by the proposed Desert Rock Energy Project; and

WHEREAS, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution; and

WHEREAS, mercury is a known pollutant emitted from coal-fired electric power generating plants; and

WHEREAS, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury; and

WHEREAS, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County; and

WHEREAS, additional monitoring sites may be needed in the County to measure current levels of ozone, and mercury in order to assess the additional impact of the proposed power plant; and

WHEREAS, the Commissioners of Montezuma County find that additional air and water monitoring sites may be needed elsewhere in the County to adequately assess the impact of air pollution and water contamination,

NOW THEREFORE BE IT RESOLVED THAT the Commissioners request that the Regional Administrator of the United States Environmental Protection Agency, Denver seek funding for equipment, operation and data analysis in its Fiscal Year 2006 and 2007 budgets for air and water monitoring equipment, as Montezuma County assumes no responsibility for the purchase, operation and data analysis of any equipment associated with this resolution, to be placed at sites throughout Montezuma County.

Commissioners voting aye in favor of the resolution were:

Commissioners voting nay against the resolution were:

________________ ________________ ________________

Carol Tullis
County Clerk and Recorder
Montezuma County, Colorado

I certify that the above Resolution is a true and correct copy of same as it appears in the minutes of the Board of County Commissioners of Montezuma County, Colorado and the votes upon same are true and correct.

Dated this 13th day of June, 2005.

Carol Tullis
County Clerk and Recorder
Montezuma County, Colorado

BUDGETS / FUNDING AND PROJECTED COSTS

Once the task of identifying suitable monitoring site locations has been completed, funding must be obtained to set up and operate the sites.

Capital costs and operating costs of a monitoring site will vary according to what parameters the site is measuring. The following spreadsheets show examples of capital and operating costs of two different monitoring sites.

The Shamrock site is under the jurisdiction of the IMPROVE **(Interagency Monitoring of Protected Visual Environments)** federal program and the Deming site is a state-run SLAMS **(State/Local Air Monitoring Stations)** site.

Funding of these types of sites usually comes from the federal government, but as federal budgets are cut, other resources have to be sought out. States have entered into partnerships with industry in order to fund monitoring activities. Various permit fees can be instituted or increased to obtain funds for monitoring. Private organizations can also be possible sources of funding.

A spreadsheet of possible funding sources is also shown. This spreadsheet lists organizations that are potential sources of funding, the geographic areas supported, applicant requirements, and the highest recent grants awarded. Most of these private funders require that grant recipients be non-profit, 501 (c) (3) organizations. Many of the funders also like projects that are collaborations and creative efforts capable of replication in other areas. They might support joint non-profit/governmental projects.

Shamrock Monitoring Site Capital Costs

Description	Qty	Unit Price	Total Price	NOTES
NOX Analyzer	1	10,000.00	10,000.00	
O3 Analyzer	1	0.00	0.00	From other site
NOx Calibration Devices	1	8,000.00	8,000.00	
IMPROVE Aerosol 4 Modules	1	16,000.00	16,000.00	
IMPROVE Housing Installation	1	5,000.00	5,000.00	
Climate Controlled Monitoring Shelter	1	9,000.00	9,000.00	
Data Logger	1	5,000.00	5,000.00	
Installation for Data Logger	1	5,000.00	5,000.00	
Laptop Computer	1	2,500.00	2,500.00	
Meteorology Station	1	4,000.00	4,000.00	
TOTAL			**$64,500.00**	

Shamrock Monitoring Site Annual Operating Costs

Description	Qty	Unit Price	Total Price	NOTES
Power and Phone	1	1,000.00	1,000.00	
Data Handling Contract	1	25,000.00	25,000.00	Data handling, digital photography, calibration, and reporting for NOx, Ozone, and Meteorology
IMPROVE Contract Fees	1	33,000.00	33,000.00	Analysis, reporting, and QA/QC
Labor	1	4,000.00	4,000.00	Total annual labor for: Weekly calibration, maintenance, and data downloads
TOTAL			**$63,000.00**	

Deming Monitoring Site Capital Costs

Description	Qty	Unit Price	Total Price
Thermo 42i NOX Analyzer	1	6,464.68	6,464.68
Thermo 49i O3 Analyzer	1	4,422.88	4,422.88
R&P TEOM PM10 Analyzer	1	17,500.00	17,500.00
Monitoring Shelter; Morgan Bldg	1	6,000.00	6,000.00
Intake Manifold	1	1,356.00	1,356.00
Sabio Calibrator	1	10,975.00	10,975.00
Sabio Keyboard	1	50.00	50.00
Sabio Zero Air Supply	1	2,447.00	2,447.00
Serial Cable; Sabio to Sabio	1	15.00	15.00
Null Modem Cable; Sabio to Computer	1	15.00	15.00
Solenoid Valves	2	215.00	430.00
Solenoid Valve Driver Cable	1	40.00	40.00
SS "T"'s (1/8" NPT to 1/4" OD)	2	17.60	35.20
SS Elbows (1/8" NPT to 1/4" OD)	4	15.00	60.00
Solenoid Valve Mounting Bracket	1	50.00	50.00
1/4" Teflon Tubing (50 ft)	0.2	350.00	70.00
1/8" Teflon Tubing (50 ft)	0.2	450.00	90.00
1/4" SS Plugs (caps)	4	7.50	30.00
1/8" SS Plugs (caps)	4	5.50	22.00
Glass Funnels	2	15.00	30.00
Surgical Tubing (50 ft)	0.2	40.00	8.00
EPA NO Protocol Gas Standard	1	258.00	258.00
Gas Regulator	1	625.00	625.00
Gas Cylinder Wall Mounting Bracket	1	25.00	25.00
Serial Cables; asst'd lengths, Air Monitors to Computer Moxa Cable	3	15.00	45.00
8-Port Moxa Card	1	300.00	300.00
Moxa Cable; 8 strand	1	55.00	55.00
Campbell Data Logger (CR10x)	1	1,779.00	1,779.00
12v Battery for Data Logger	1	25.00	25.00
Power Adapter for Data Logger	1	10.00	10.00
SC32B Optically Isolated Interface	1	80.00	80.00
APC UPS	1	200.00	200.00

Description	Qty	Unit Price	Total Price
Wireless Modem	1	500.00	500.00
Computer, monitor, keyboard, mouse	1	3,000.00	3,000.00
MET Tower Base; B-14	1	75.00	75.00
MET Tower	1	511.00	511.00
Lightning Rod	1	15.00	15.00
Grounding Rod	1	25.00	25.00
Rod Clamps	2	15.00	30.00
Tower Mast	1	35.00	35.00
Tower Cross Bar	1	35.00	35.00
Hardware Crosses, standard and offset	1	15.00	15.00
Solar Sensor (Li 200 SA 50)w/ Cable	1	215.00	215.00
Solar Sensor Mv Adapter (2220)	1	27.00	27.00
Solar Sensor Mounting Base	1	44.00	44.00
Solar Sensor Mounting Arm	1	65.00	65.00
Wind Monitor Unit (05305-5 AQ)	1	1,200.00	1,200.00
Wind Monitor Cable (50 ft)	1	50.00	50.00
Temperature Probes w/ Cable	2	425.00	850.00
Temperature Probe Aspirator	2	726.00	1,452.00
Power Installation	1	1,500.00	1,500.00
Security Fencing	1	1,600.00	1,600.00
TOTAL			**$ 64,756.76**

Deming Monitoring Site Annual Operating Costs

Description	Qty	Unit Price	Total Price
Power:	1	845.00	845.00
Communications:	1	830.00	830.00
Labor:	1	5,285.00	5,285.00
Consumables:	1	1,500.00	1,500.00
TOTAL			**$ 8,460.00**

Possible Funding Sources for Monitoring

Name & contact info	Areas Funded	Applicant requirements	Highest Recent Grant
PRIVATE SOURCES			
Ben & Jerry's Foundation (802) 846-1500 www.benjerry.com/foundation	national	501(c)(3)	$15,000
Patagonia, Inc. (805)643-8616 www.patagoniainc.com	Colorado	501(c)(3)	$20,000
Coutts & Clark Western Foundation (970) 259-6169 thinair@starband.net	SW CO multi-state	501(c)(3)	$5,000
William & Flora Hewlett Foundation (650) 234-4500 www.hewlett.org	national	501(c)(3)	$2,400,000
Microsoft Corp. Rocky Mountain Region (720) 528-1700 sandyp@microsoft.com	Rocky Mountain area	501(c)(3) local govt. entity?	$30,000
Anschutz Family Foundation (303) 293-2338 info@anschutzfamilyfoundation.org	Colorado, especially rural	501(c)(3)	$20,000
Eastman Kodak Charitable Trust (585)724-2434 www.kodak.com/us/en/corp/community.shtml	Colorado	501(c)(3)	$250,000

Name & contact info	Areas Funded	Applicant requirements	Highest Recent Grant
Greenlee Family Foundation (303) 444-0206 directorgff@aol.com	SW CO	501(c)(3)	$10,000
El Pomar Foundation 800-554-7711 grants@elpomar.org	Colorado	501(c)(3)	$1,550,000
Ford Motor Company Fund (313) 845-8711 fordfund@ford.com	National	501(c)(3)	$265,000

ADDITIONAL SOURCES FOR INFORMATION ON PRIVATE FUNDING FOR ENVIRONMENTAL PROJECTS

Environmental Grant Makers Association
(212 812-4260
shansen@ega.org

Community Resource Center, Inc.
(303) 623-1540
www.cramerica.org

SUMMARY OF SUGGESTIONS / PRIORITIES

Introduction

Air pollution is defined as a chemical, physical or biological agent that modifies the natural characteristics of the atmosphere.[1] Pollutants in the air may be natural in origin, such as blowing dust, forest fire smoke or organic compounds from vegetation. Of greater concern are anthropogenic, or man-made pollutants. These include chemicals and particulates from motor vehicles, smoke stacks, incinerators, refineries, industrial degreasing and pesticides, to name just a few. Pollutants may be classified as primary, where they are directly released form a source, or as secondary, where they are formed from reactions of other pollutants in the atmosphere. The health effects caused by air pollutants may range from subtle biochemical and physiological changes to difficulty breathing, wheezing, coughing and aggravation of existing respiratory and cardiac conditions. These effects can result in increased medication use, increased doctor or emergency room visits, more hospital admissions and premature death.[1]

Air pollution has been an issue to human health for centuries. One of the most famous episodes was the “Great Smog” that occurred in London, England in December 1952. Lasting for four days, over 12,000 people died either during the episode or in the months following as a result of the health effects.[2] While not the first air pollution smog to cause deaths, it was the largest to date and led to some of the first Clean Air Acts and air quality regulations in the world. In the United States, the first Clean Air Act was passed in 1963. However, it was not until the Clean Air Act of 1970 and with the creation of the U.S. Environmental Protection Agency (EPA) in the same year that real air pollution control came into full force.[3] This 1970 Clean Air Act was revised and expanded in 1990.

The U.S. EPA has set national ambient air quality standards (NAAQS) for six “criteria” pollutants. These are wide-spread pollutants from numerous and diverse sources that are considered harmful to public health and the environment. There are two types of NAAQS. Primary standards set limits to protect public health, including the health of “sensitive” populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings.[4] The “criteria” pollutants are carbon monoxide, ozone, sulfur dioxide, nitrogen dioxide, lead and particulates (PM_{10} and $PM_{2.5}$). However, there are many other pollutants that can be found in the ambient air. Air toxics, which includes a variety of organic compounds and metals, is an area of increasing concern to human health. Visibility, while not directly a health-related concern, is an aesthetic concern and can be an indicator of other health-related pollutants. The sources and health/environmental impacts vary from pollutant to pollutant, though many are linked to each other.

Carbon monoxide is a colorless and odorless gas formed primarily from incomplete combustion of fuels. It is a product of motor vehicle exhaust, which contributes about 60 percent of all carbon monoxide emissions nationwide. Other sources of carbon monoxide emissions include industrial processes, non-transportation fuel combustion, and natural sources such as wildfires. With increasing emissions controls on motor vehicles and other sources, ambient carbon monoxide levels nationwide have been reduced significantly over the past two decades. Carbon monoxide enters the bloodstream through the lungs and reduces oxygen delivery to the body's organs and tissues. The health threat from carbon monoxide is most serious for those who suffer from cardiovascular disease. Visual impairment, reduced work capacity, reduced manual dexterity, poor learning ability, and difficulty in performing complex tasks are all associated with exposure to elevated carbon monoxide levels.[5]

Ozone is a highly reactive gas that is a form of oxygen. Though it occurs naturally in the stratosphere to provide a protective layer high above the earth, at ground-level it is the prime ingredient of smog.[6] Ozone is a secondary pollutant formed by the action of sunlight on carbon-based chemicals known as hydrocarbons, acting in combination with a group of air pollutants called oxides of nitrogen. As a result, ozone is generally a summer afternoon issue. Ozone reacts chemically with internal body tissues that it comes in contact with, such as those in the lung. It also reacts with other materials such as rubber compounds, breaking them down. Health symptoms include shortness of breath, chest pain when inhaling deeply, wheezing and coughing. Research on the effects of prolonged exposures to relatively low levels of ozone have found reductions in lung function, biological evidence of inflammation of the lung lining and respiratory discomfort.[7]

Sulfur dioxide is a gas that is formed when fuel containing sulfur (mainly coal and oil) is burned, and during metal smelting and other industrial processes. The major health concerns associated with exposure to high concentrations of sulfur dioxide include effects on breathing, respiratory illness, alterations in the lungs defenses, and aggravation of existing cardiovascular disease. Asthmatics and individuals with cardiovascular disease or chronic lung disease, as well as children and the elderly are particularly susceptible. In addition, sulfur dioxide is a major precursor to $PM_{2.5}$ particulates and acid rain.[8]

Nitrogen dioxide is a light brown gas that can become an important component of urban haze. Oxides of nitrogen (which includes nitrogen dioxide) usually enter the air as the result of high-temperature combustion processes, such as those occurring in automobiles and power plants. Nitrogen dioxide plays an important role in the atmospheric reactions that generate ozone. Home heaters and gas stoves also produce substantial amounts of nitrogen dioxide. Nitrogen dioxide can irritate the lungs and lower resistance to respiratory infections. Oxides of nitrogen are an important precursor to ozone, $PM_{2.5}$ particulates and acid rain.[9]

Lead is a metal that is used in a wide variety of commercial products. In the past, automotive sources were the major contributor of lead emissions to the atmosphere. As a result of unleaded fuels now being used, ambient lead levels have decreased significantly. Today, metals processing is the major source of lead emissions to the atmosphere. The highest concentrations of lead are found in the vicinity of nonferrous and ferrous smelters, battery manufacturers, and other stationary sources of lead emissions. Exposure to lead occurs mainly through the inhalation of air and the ingestion of lead in food, water, soil, or dust. It accumulates in the blood, bones, and soft tissues. Because it is not readily excreted, lead can also adversely affect the kidneys, liver, nervous system, and other organs. Excessive exposure to lead may cause neurological impairments such as seizures, mental retardation, and/or behavioral disorders. Recent studies also show that lead may be a factor in high blood pressure and subsequent heart disease.[10]

Particle pollution is a mixture of microscopic solids and liquid droplets suspended in the air. This pollution, also known as particulate matter, is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, soil or dust particles, and allergens (such as fragments of pollen or mold spores).[11] Particulate pollution comes from such diverse sources as factory and utility smokestacks, vehicle exhaust, wood burning, mining, construction activity, and agriculture.[12] The size of particles is directly linked to their potential for causing health problems. Small particles less than 10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream. Exposure to such particles can affect both your lungs and your heart. Particulate matter air pollution is especially harmful to people with lung disease such as asthma and chronic obstructive pulmonary disease (COPD), which includes chronic bronchitis and emphysema. Exposure to particulate air pollution can trigger asthma attacks and cause wheezing, coughing, and respiratory irritation in individuals with sensitive airways. Larger particles are of less concern, although they can irritate your eyes, nose, and throat.

Toxic air pollutants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. Examples of toxic air pollutants include benzene, which is found in gasoline; perchlorethlyene, which is emitted from some dry cleaning facilities; and methylene chloride, which is used as a solvent and paint stripper by a number of industries. Examples of other listed air toxics include dioxin, asbestos, toluene, and metals such as cadmium, mercury, chromium, and lead compounds.[13] There are no NAAQS for toxic air pollutants. Instead, they are regulated nationally by requiring the use of pollution controls on sources.

Visibility is defined as the greatest distance at which a black object can be seen and recognized when observed against a background fog or sky. From an aesthetic perspective, visibility represents not just visual range, but rather the overall visual experience of a scene.[14] Thus, visibility issues are not directly a health impact. However, many of the pollutants that cause visibility degradation may cause health impacts. In addition to primary particulates, secondary particulates are a part of visibility degradation. These secondary particulates can be formed from sulfur dioxide and nitrogen dioxide, both of which are criteria pollutants.

Both N and sulfur (S) oxides can form "acid rain" and lead to acidification of surface and groundwater and soils. S oxides primarily are emitted to the atmosphere by burning of fossil fuels.

Increased deposition of atmospheric N can result in high levels of nitrate in surface and ground water, shifts in species, decreased plant health, and eutrophication (i.e., fertilization) of otherwise naturally low-productivity ecosystems.

Analysis and Interpretation of Existing Data

Meteorology

Meteorological data are collected at a number of different locations in the Four Corners region.

In looking at the annual wind roses, it is evident that some sites are more influenced by local topography than others. An example is the Cortez CoAgMet site, which is located in the valley between Sleeping Ute Mountain and Mesa Verde and is subjected to definite channeling effects. Another example is the U.S. Forest Service Shamrock site, which is located on the side of a hogback ridge. It can also be seen that the strongest winds are generally from a more westerly direction than an easterly one. From the daytime wind roses, there are general westerly or northerly/southerly components to the winds. In comparison, the nighttime wind roses show more of general easterly to northerly components. These trends are expected based on prevailing regional wind patterns as well as more local convection heating and cooling patterns along with topography.

These wind roses can be broken down even further, such as only for summer afternoon periods when ozone levels are expected to be highest (see summer afternoon wind rose maps). These wind roses show, in general, a predominant westerly to southwesterly component. As mentioned previously, some sites still exhibit wind patterns that are strongly influenced by local topography rather than more regional winds. However, these types of plots are useful in describing what may happen with air pollution flows during different periods of time. While not performed for this analysis, additional seasonal plots could be dome, such as for winter when inversions are more prevalent.

Ozone and Precursor Gases

Ground level ozone is currently monitored on a continuous basis at nine locations in the Four Corners region, with seven sites being in a core area. For regulatory comparisons to the NAAQS, continuous analyzers that have been designated as “equivalent’ or “reference” by the U.S. Environmental Protection Agency (EPA) are used.

Currently, ambient ozone levels in the Four Corners region are below the level of the current NAAQS (see trends and standards graphs). However, at Mesa Verde and one Southern Ute site there is an increasing trend, and the two newer sites (USFS, Navajo Lake) are recording higher levels. Many of the sites would be above the level of a reduced NAAQS, as proposed by CASAC.

With ozone typically having peak concentrations in the summer afternoons when sunlight is strongest, pollutant roses were developed accordingly and were placed on both political boundary and topographic base maps (see pollutant rose maps). As can be seen from these pollutant rose maps, ozone at the three southern core area sites in New Mexico and the Mesa Verde site in Colorado show predominantly westerly wind directions in this summer afternoon timeframe. This generally mirrors the predominant San Juan River drainage. The two Southern Ute Tribe sites and the Forest Service Shamrock site appear to be heavily influenced by local topography. Thus, based on these pollutant roses, it is likely that ozone concentrations could also be high further to the east and north of the New Mexico Navajo Lake site, further up the San Juan River and Piedra River drainages. While no monitoring exists to confirm or deny, winds could also flow up other drainages in summer afternoons, including the Dolores and Animas Rivers.

For ozone precursor gases, NOx monitoring currently exists at six sites in the Four Corners region. NO_2 levels have been fairly steady over the years at most sites, at a level well below the NAAQS. At two sites in particular, San Juan Substation, NM and Bloomfield, NM, the NO_2 levels do appear to be increasing over time.

NO, unfortunately, has not been reported consistently as it is not designated a criteria pollutant. However, NO levels do appear to be increasing at both Southern Ute Tribe sites, Ignacio and Bondad. These increases in NO and NO_2 are of concern due to the potential for increased ozone formation and also indicates that there are increased combustion sources in the area, possibly due to oil and gas development and increased traffic.

VOC baseline monitoring for San Juan County, New Mexico was conducted in 2004 and 2005 at three sites. One site was near Bloomfield, NM near some industrial sources, a second near the San Juan power plant and the third site was near Navajo Lake, in an oil and gas development area. Results showed that alkane concentrations dominated, especially ethane and propane. The biogenic compound isoprene and the highly reactive VOC compounds, ethylene and propylene, were not present in significant quantities.

Mercury

Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network. Results show mercury concentrations among the highest in the nation during certain years. Precipitation is relatively low, however, so mercury in wet deposition is moderate. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS and moderate concentrations similar to the Colorado Front Range have been recorded. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for water bodies including McPhee, Narraguinnep, Todden, Navajo, Sanchez and Vallecito Reservoirs and segments of the San Juan River. Atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these water bodies, respectively.

Nitrogen and Sulfur Compounds

Currently, monitoring stations for N, S, and H+ in wet deposition exist at Mesa Verde National Park (since 1981), Molas Pass (since 1986), and Wolf Creek Pass (since 1992) as part of the National Atmospheric Deposition Program. Dry deposition of N and S, which is especially important in arid regions (Fenn et al. 2003), has been monitored since 1995 at Mesa Verde NP as part of the Clean Air Status and Trends Network.

Trends of sulfate concentrations in wet deposition show either a decrease over time or no change at monitoring stations in the vicinity of the Four Corners region. Conversely, trends of nitrate and ammonium concentrations in wet deposition appear to be stable or increasing. In general, N in wet deposition in the Four Corners and San Juan Mountain region currently is at or above the 1.5 kg/ha/yr ecological critical load discussed above for Rocky Mountain National Park. Dry deposition data from Mesa Verde NP indicate that, for the period 1997-2000, dry deposition contributed about half of the total inorganic nitrogen deposition and about one-third of the total sulfur deposition. The short data record is insufficient to detect trends over time for dry deposition. Model simulations of total wet plus dry deposition of N in the western United States indicate a possible hotspot for N deposition in SW Colorado.

Visibility

Currently, there are four sites within the Four Corners region that monitor visibility: Mesa Verde National Park, the Weminuche Wilderness (near Purgatory,) the Shamrock Mine (southeast La Plata County,) and Canyonlands National Park. Of these four sites, only the Forest Service monitoring station at the Shamrock Mine records images, and is included in IMPROVE’s optical and scene monitoring network. Additionally, because the Canyonlands site lies on the margin of the Four Corners Region, and it is also located at a comparatively lower elevation north of the Blue Mountains, it may not serve as the best indicator of visibility trends in the Four Corners proper.

Preliminary analysis of deciview trends at Mesa Verde, and also of visibility-impairing gasses and particulates as monitored at other sites, does not reveal a clear trend of how visibility might be changing in the Four Corners. This appraisal is not concomitant with the observations of many area residents. It may be indicative of monitoring gaps that exist in the Four Corners, and it has led to the perception by members of the Task Force Monitoring Group that a comprehensive, detailed analysis of all available data regarding visibility is greatly needed.

Despite that ambiguity, however, there are a few details worth noting. In September of 2005, the Interim Emissions Workgroup of the Four Corners Air Quality Task Force recommended that an ambient monitoring program for gaseous ammonia be initiated in the Four Corners region. The purpose of this program is to set a current baseline of ambient gaseous ammonia concentrations in the Four Corners, that can be compared to monitored values in approximately 3-5 years after the implementation of NOx controls (e.g. NSCR) on oil and gas equipment. The use of NSCR may increase ammonia emissions in the area, but these emissions have not been quantified and may or may not significantly affect visibility. Ammonia at high enough concentrations can contribute to worsening visibility by forming PM 2.5 ammonium nitrates and ammonium sulfates.

Additionally, the implementation of new SO_2 controls at the San Juan Generating Station in 1999 has successfully reduced SO_2 emissions in the area. Because of the high impact that SO_2 can have upon visibility, that reduction has likely made a positive impact upon visibility conditions in the Four Corners. However, changes in monitoring conditions at San Juan Substation have not been limited to a decrease in SO_2. Concurrently, it appears that NOx concentrations have risen, and now dominate over SO_2.

Carbon Monoxide, PM_{10} and Other Common Pollutants

Carbon Monoxide

Carbon monoxide in the ambient air is currently monitored on a continuous basis at only one site in the Four Corners region. This is at the Southern Ute Tribe's Ignacio site in southern Colorado. Monitoring was performed at New Mexico's Farmington site, but was discontinued in 2000. Ambient carbon monoxide levels in the Four Corners region are well below the level of the current NAAQS.

PM_{10}

PM_{10} in the ambient air is, historically, the most heavily monitored pollutant in the Four Corners region. Most of the monitoring has been performed using filter-based "high-volume" samplers that collect 24-hour samples and most of the data are available on EPA's Air Quality System. Ambient PM_{10} levels in the Four Corners region are well below the level of the current and former NAAQS.

Others

No monitoring for lead exists in the Four Corners region. Due to the introduction of unleaded gasoline in the 1970's, ambient lead levels have decreased to levels that are near instrument detection levels. Likewise, no monitoring exists for other pollutants such as carbon dioxide, HAPs or pesticides.

<u>Suggestions for Future Monitoring Work</u>

Meteorology

No significant data gaps exist for meteorological monitoring in the Four Corners region, with the exception of southwestern Utah and northeastern Arizona. No suggestions for additional monitoring of meteorological parameters are currently being proposed.

Ozone and Precursor Gases

While it would appear that there is a sufficient ozone monitoring network in the Four Corners region, some areas are lacking. Pollutant roses were developed to determine the directions from which ozone precursors are most likely to be transported by wind. Ozone monitoring currently exists in the major oil and gas development areas, but little downwind ozone monitoring currently exists.

VOCs are also a gap, as the short-term studies in 2004 and 2005 were located toward the southern edge of the oil and gas development area, or not in the development area at all. While emissions inventories can provide an estimate of total VOCs that may be released to the atmosphere, these are primarily based on predicted emissions, not on actual measurements. This is a concern as different VOCs have different ozone formation potentials and the oil and gas development has dramatically increased in the region since these studies.

<u>Suggestions for Future Monitoring Work for Ozone:</u>

Install and operate two or three long-term continuous monitoring stations for ozone. One station would be located upstream of Navajo Lake, in the San Juan River drainage toward Pagosa Springs, CO, or in the Piedra River drainage, toward Chimney Rock, CO. This area is toward the northeastern portion of the Four Corners region and is downwind of many VOC precursor gas sources from oil and gas development. The second station would be located to the north of Cortez. This area is in the north-central portion of the Four Corners region and is downwind of both an urban area and any precursor gas emissions that would funnel up between Sleeping Ute Mountain and Mesa Verde. If funding exists, a third site in Arizona on Navajo Nation land, in the southwest portion of the Four Corners area, is recommended. This site, possibly at Canyon de Chelly National Monument, would be to the west of a high ozone area as determined in the 2003 passive ozone study and would provide a good representation of regional ozone levels entering the Four Corners area. Each site, including shelter and instrumentation, would cost approximately $15,000 to $20,000 (total = $45,000 to $60,000). Annual operating costs (not including field personnel) would be approximately $1,500 per site (total = $3,000).

Perform an ozone saturation study using passive samplers across the entire Four Corners region to determine areas of highest ozone concentration. This would help determine if existing or new continuous monitoring sites are located in appropriate areas or if continuous ozone monitors need to be added or moved. It is expected that at least 20 passive ozone sites over the four-state region would be needed. Running for 30 days during a summer, the approximate cost would be $22,000 (not including field personnel time).

Perform monitoring for VOCs (in particular NMOCs) and carbonyls in the oil and gas development areas to determine the actual constituents in the emissions from wellheads, leaks and tanks. This would help in determining the potential for ozone formation from these compounds. This suggestion also includes follow-up monitoring for VOCs, both in and near the oil and gas development area, to compare to the 2004 and 2005 baseline data from San Juan County, New Mexico. A minimum of four to five sites is recommended; two sites in the oil and gas development area, one background site and one or two follow-up sites. For a year of monitoring, every sixth day, the approximate cost (not including field personnel time) would be $45,000 per site (total = $180,000 to $225,000).

Mercury

Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. No data exists for mercury in deposition at high elevations. Wet deposition of mercury at Mesa Verde National Park may not portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of water bodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

Suggestions for Future Monitoring Work for Mercury:

1. Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

2. Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

3. Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., suggestions 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html9). Costs TBD.

4. Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

5. Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

6. Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

Nitrogen and Sulfur Compounds

While data for N in wet deposition exist from multiple sites in the region, dry deposition is studied only at Mesa Verde National Park, which does not represent higher-elevations common near the Four corners region. Data concerning ecological effects of N deposition are very sparse for both high and low elevations and the limited data that do exist have not been analyzed adequately. No data exists for N and S deposition in the vicinity of emission sources. For example, no monitoring of N and S in wet or dry deposition occurs in NW New Mexico with the exception of Bandelier National Park.

Suggestions for Future Monitoring Work for Nitrogen and Sulfur Compounds:

Continue monitoring for N, S and H+ in wet deposition via the NADP at the Molas Pass, Wolfe Creek Pass and Mesa Verde National Park sites. Consider adding a site closer to emissions sources in NW New Mexico.

Initiate long-term monitoring / modeling of N and S in dry deposition via the Clean Air Status and Trends Network (CASTNet) at a site such as Molas Pass, which is at higher elevation than the one existing site at Mesa Verde NP. Consider adding an additional site closer to emissions sources in NW New Mexico.

Complete a full analysis of existing Wilderness Lakes data, including spatial and temporal trends and correlation of measurements with watershed or lake characteristics.

Support a suite of ecological studies in order to measure potential harmful effects of N deposition on natural resources across an elevation gradient. The studies should include an observational component aimed at documenting changing ambient conditions, but experimental manipulations should also be used to understand cause and effect relationships in addition to potential future responses. These studies should be modeled after those conducted in the Colorado Front Range, California, etc.

Visibility

Most visibility monitoring in the Four Corners is unevenly distributed (or restricted) to Class I areas. Therefore, visibility monitoring within these Class I areas is not conducive of a regional trends assessment, especially because they are based on a very few site-specific particulate measurements. Furthermore, the regional monitoring of visibility is desirable, because it can assist with the protection of Class I areas and EPA's regional haze rule. Additionally, regional monitoring of visibility will better address the value that citizens place upon the vistas that exist outside of Class I areas, while recognizing how visibility impacts citizens' perceptions of air quality as a whole. In sum, it is highly desirable that we consider how visibility monitoring in the Four Corners region can be perfected, with the intent of making a *strong regional assessment*.

1. It is recommended that the monitoring sites at Mesa Verde and in the Weminuche resume photographic documentation.

2. Many previous studies of visibility in the Four Corners relate only to site-specific locations, and often conflict in their findings. A comprehensive assessment of historical data is needed, in order to determine regional trends or changes in visibility. Currently, it is very difficult not only to establish regional trend analyses, but also to compare them to historical baseline data.

3. Additional visibility monitoring should be established at locations in the region other than what exists in Class I areas. This additional monitoring:

    D. could be incorporated into existing monitoring sites;
    E. should include photographic documentation;
    F. and, it should specifically consider how topographical variations impact the measurement of visibility.

4. The apparent contribution of NOx emissions to wintertime visibility impairment is recommended for further study.

Carbon Monoxide, PM_{10} and Other Common Pollutants

No suggestions for additional monitoring of carbon monoxide, PM10 and other common pollutants are currently being proposed.

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RESPONSES TO "MONITORING" COMMENTS

(by Gordon Pierce)

1. Kandi & David LeMoine, 7/17/2007
"… I reviewed what the monitoring group put together, and I think they did an excellent work."

The workgroup would like to say thanks! (No changes to the report.)

2. BP, 7/13/2007
"While the Draft Report suggestion for addition of new monitoring sites will provide valuable insight to understanding air quality in the region, a detailed analysis of current monitoring data also needs to be conducted to identify trends in air quality. In addition, analyzing trends in monitoring data in conjunction with changes in emissions will provide an important understanding of atmospheric processes. Also, it may be possible to evaluate monitoring data to assist in understanding source receptor relationships.
Confidence limits need to be developed based on monitoring accuracy and precision to determine if observed trends in data are statistically significant or simply random variations in analytic methods. There are also bounding calculations that could be performed that may assist in determining how changes in emissions may change visibility. Such calculations would entail using the IMPROVE data and ratioing the concentrations to calculate the improvement in visibility and establish an upper bound of visibility improvement.
It is recommended that the Task Force conduct a detailed analysis of the IMPROVE monitoring data in the region since BP believes that such an analysis would assist in developing meaningful strategies for improving air quality in the region. BP would welcome the opportunity to assist in establishing a scope of work for such an activity."

(Full response to be written by Sylvia Oliva.) The workgroup agrees that it would be nice to do more with trends analyses, confidence limits and IMPROVE data analyses. However, this was much more work than the workgroup had time to do. (No changes to the report.)

3. Jeanne Hoadley, 7/10/2007
"I would find it helpful if the wind roses on the maps were labeled with the station name."

The workgroup debated extensively as to how much information should be included on the wind rose maps. It was felt that adding more information would make the maps too cluttered and that station names should be presented separately. Thus, maps with only the station names and elevations are presented immediately preceding the wind rose maps. (No changes to the report.)

4. Jeanne Hoadley, 7/10/2007
"Under existing ozone data for the four corners region it says a Navajo Nation site is scheduled to begin operating in Shiprock but doesn't say when. If it is scheduled this implies we know when and we should say. If we don't know when we should say it is expected to begin operating soon."

At the time this subsection was written, there was not a specific date as to exactly when the Navajo Nation would be able to get their new air monitoring site fully operational. In further conversations with the Navajo Nation, the date is still uncertain due to electrical power issues. The report will be revised so that the text reads that the site is planned to commence operation by the end of 2007. (See report for revision under OZONE AND PRECURSOR GASES subsection, "Existing Ozone Data for the Four Corners Region".)

5. Jeanne Hoadley, 7/10/2007
“Under existing ozone data for the four corners region it says a Navajo Nation site is scheduled to begin operating in Shiprock but doesn't say when. If it is scheduled this implies we know when and we should say. If we don't know when we should say it is expected to begin operating soon.
The next sentence has a typo...the "closest" Arizona site.”

Thank you for catching the typo. The word will be revised from “closes” to “closest”. (See report for revision under OZONE AND PRECURSOR GASES subsection, “Existing Ozone Data for the Four Corners Region”.)

6. Mark Jones, 7/10/2007
“Comment on behalf of Roy Paul, "Why is there no ozone monitoring on the Western Slope of Colorado?"”

There are questions as to whether this comment is referring to the southwest/Four Corners area of Colorado or further north, such as around Mesa and Garfield counties in Colorado. For the southwest/Four Corners area, which is the focus of this workgroup, ozone monitoring is currently performed at four locations in Colorado. These locations are shown on the map in the “Ozone and Precursor Gases” subsection of the report. In addition, for recommendation #2 in the subsection, a passive ozone study was performed in the area during August 2007 using monies recently appropriated by the Colorado legislature. A revision to address this is made under recommendation #2. (See report for revision under OZONE AND PRECURSOR GASES subsection, recommendation #2.)

7. Jeanne Hoadley, 7/10/2007
“The pollutants in the header seem to be out of place in this table.”

This appears to have been an issue with the software and comment version of the report on the website. The tables are correct in the actual report. (No changes to the report.)

8. Jeanne Hoadley, 7/10/2007
“Again the header in this table is messed up, making it impossible to understand.”

This appears to have been an issue with the software and comment version of the report on the website. The tables are correct in the actual report. (No changes to the report.)

9. Jeanne Hoadley, 7/10/2007
“Mercury- Rationale and Benefits. It is not clear to me why Weminuche Wilderness is singled out here...there are many other Class 1 areas in or near this region.”

(Full response to be written by Koren Nydick.) The commenter is correct in that other Class 1 areas are in the region. Weminuche was simply being used as an example. Mercury will be clarified in the report and other Class 1 areas will also be listed or mapped. (See revisions from Koren Nydick.)

Response to BP's Comments

(by Sylvia Oliva)

"Detailed analysis [analyses] of current monitoring data" including trends and back trajectories are already available on the Interagency Monitoring for the Projected Visual Environment, IMPROVE, web site (http://vista.cira.colostate.edu/improve/). Mesa Verde National Park data reaches back to the early 1990s. The highest standard possible for "accuracy and precision" of IMPROVE filters is well-established by the monitoring analysis agency: Crocker Nuclear Labs, University of California at Davis.

IMPROVE filter analyses include x-ray spectroscopy and related techniques. The filters themselves are of several different materials to best trap different aerosols and particulates. (This is why, unfortunately, data availability is traditionally in arrears for 12 to18 months.) Furthermore, any changes in filter composition or analysis protocol through the years are precisely notated in the preamble for accessing raw data for either single or groups of IMPROVE sites, single or groups of parameters.

It indeed would contribute to important understanding of atmospheric processes to take IMPROVE trend data (already available as previously mentioned) with emissions changes to assist in "understanding source-receptor relationship[s]." The caveat, here is that Mesa Verde data is not truly representative of visibility impairment in that the park's physical location (and therefore its IMPROVE site) is really not within the impairment atmosphere, contrary to other parks, e.g. Grand Canyon NP, Yellowstone, NP, or the Great Smokies NP. Rather, the visitor at Mesa Verde sees visibility impairment from outside. Likely, Mesa Verde IMPROVE data might be matched as background with other IMPROVE station data.

So, such a tremendously laudable project correlating trends with emissions sources is not within the present financial means and scope of the current task force.

Dramatic improvements in computer processing power the past two years will quite revolutionize modeling techniques. If these techniques are already incorporated into modeling software, establishing "an upper bound of visibility improvement" may well be a more realistic task than heretofore. (See Marufu, L. T. et al, The 2003 North American electrical blackout: An accidental experiment in atmospheric chemistry, Geophys. Res. Lett., 31, L13106, doi:10.1029/2004GL019771. "The dramatic improvement in air quality during the blackout may result from underestimation of emissions from power plants, inaccurate representation of power plant effluent in emission models or unaccounted for atmospheric chemical reaction(s).")

Appendices

Acronyms

Acronyms

μeq/L	micro-equivalents per liter
μg/L	micrograms per liter
$\mu g/m^3$	micrograms per cubic meter
<	less than
>	greater than
°C	degrees Centigrade
°F	degrees Fahrenheit
4CAQTF	Four Corners Air Quality Task Force
AAQS	Ambient Air Quality Standards
AC	Alternating Current
ACI	Activated Carbon Injection
A/F	Air/Fuel
AFR(s)	Air/Fuel Ratio
AFRC(s)	Air/Fuel Ratio Controllers
AFUDC	Allowance For Funds During Construction
aka	also known as
ANGEL	Airborne Natural Gas Emission LIDAR
APCD	Air Pollution Control Division
APD	Application for Permit to Drill
APS	Arizona Public Service
AQI	Air Quality Index
AQRV	Air Quality Related Value
AQS	Air Quality Standard
AQTSD	Air Quality Technical Support Document
ARM	Air Resource Management
ARS	Agricultural Resource Service
ASTM	American Society for Testing and Materials
ASU	Air Separation Unit
AWMA	Air & Waste Management Association
AZ	Arizona
B&W	Babcock and Wilcox
BACM	Best Available Control Measure
BACT	Best Available Control Technology
BAGI	Backscatter Absorption Gas Imaging
BART	Best Available Retrofit Technology
Bbl/day	barrels per day
Bcf	billion cubic feet
bhp	Brake Horsepower
BHP	BHP Billiton, Ltd.
BLM	Bureau of Land Management (U.S. Department of the Interior)
BMP(s)	Best Management Practices
BTEX	Benzene, Toluene, Ethyl-benzene, Xylene
Btu/kw-hr	British Thermal Units per Kilowatt Hour
CA	California
CAA	Clean Air Act
Ca	Calcium
CaCl	Calcium Chloride
CaCO3	Calcium Carbonate
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CALPUFF	California PUFF Dispersion Model
CaO	Calcium Oxide (Lime)
CARB	California Air Resources Board

CARE	Citizens Against Ruining our Environment
CAS	Chemical Abstracts Service
CASAC	Clean Air Scientific Advisory Committee
CaSO4	Calcium Sulfate
CASTNET	Clean Air Status and Trends Network
CB-DPF	Catalyst-Based Diesel Particulate Filter
CBM	Coal Bed Methane
CBNG	Coalbed Natural Gas
CCAG	Climate Change Advisory Group (New Mexico)
CCC	Colorado Climate Center
CCR	Colorado Code of Regulations
CCS	Carbon Capture and Sequestration
CCV	Closed Crankcase Ventilation
CCX	Chicago Climate Exchange
CDNR	Colorado Department of Natural Resources
CDOT	Colorado Department of Transportation
CDOW	Colorado Division of Wildlife
CDPHE	Colorado Department of Public Health and Environment
CDPHE-APCD	Colorado Department of Public Health and Environment – Air Pollution Control Division
CE	Cumulative Effects
CEC	California Energy Commission
CEDF	Clean Environment Development Facility
CEM	Continuous Emission Monitor
CEMS	Continuous Emission Monitoring System
CFB	Circulating Fluidized Bed and/or Coal-fired Boiler
CFLs	Compact Fluorescent Light bulbs
CFR	Code of Federal Regulations
Cfs	Cubic Feet per Second
CGS	Colorado Geological Survey
CH2	Methylene
CH3	Methyl Group
CH4	Methane
CHP	Combined Heat and Power
CI	Compression Ignition
Cl	Chloride
CNG	Compressed Natural Gas
CO	Carbon Monoxide and/or Colorado
CO2	Carbon Dioxide
COA	Conditions of Approval
CoAgMet	Colorado Agricultural Meteorological Network
COBRA	CO-Benefits Risk Assessment
COE	Cost of Energy
COGCC	Colorado Oil and Gas Conservation Commission
COM	Continuous Opacity Monitor
CPANS/ PNWIS	Canadian Prairie and Northern Section/Pacific Northwest International Section
CTG	Control Techniques Guideline
CWCS	Comprehensive Wildlife Conservation Strategy
DC	Direct Current
DCS	Distributed Control System
DEIS	Draft Environmental Impact Statement
DEP	Department of Environmental Protection
DEQ	Department of Environmental Quality
DER	Distributed Energy Resources
DIAL	Differential Absorption LIDAR
DLN	Dry Low NOX

DO	Dissolved Oxygen
DOAS	Differential Optical Absorption Spectroscopy
DOC	Diesel Oxidation Catalyst
DOE	U.S. Department of Energy
DPA	Dinè Power Authority
DREF	Desert Rock Energy Facility
DPF	Diesel Particulate Filter
DR	Demand Response
DRMP	Draft Resource Management Plan
DSIRE	Database of State Incentives for Renewable Energy
DV	Deciview
E	East
E&P	Exploration and Production
EA	Environmental Assessment
EAC	Early Action Compact
EBETS	Economic Incentives-Based Emission Trading System
ECBMR	Enhanced Coal Bed Methane Recovery
ECM	Electronic Control Module
EE	Energy Efficiency
EEREC	Energy Efficiency, Renewable Energy and Conservation
EGR	Exhaust Gas Recirculation
eGRID	Emissions and Generation Integrated Resource Database
EGU	Electric Generating Unit
EIS	Environmental Impact Statement
ENGR	Enhanced Natural Gas Recovery
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
EPCA	Energy Policy and Conservation Act
EPD	Environmental Protection Division
EPRI	Electric Power Research Institute
ERMS	Emission Reduction Market System
ESP	Electrostatic Precipitator
ETC	Environmental Technology Council
ETS	Emission Trading System
F	degrees Fahrenheit
F-T	Fischer-Tropsch
FAQs	Frequently Asked Questions
FBC	Fuels Borne Catalyst
FCOTF	Four Corners Ozone Task Force
FCPP	4 Corners Power Plant
FEIS	Final Environmental Impact Statement
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FLAG	Federal Land Managers' AQRV Workgroup
FLM	Federal Land Manager
FR	Federal Register
FS	Forest Service (U.S. Department of Agriculture)
Ft	feet
FTF(s)	Flow Through Filter
FY	Fiscal Year
G	gram
g/bhp-hr	grams per brake horsepower-hour
g/hp-hr	grams per horsepower-hour
GF	Growth Fund
GHG(s)	Greenhouse Gases
GIS	Geographic Information System

GOR	Gas Oil Ratio
GVW	Gross Vehicle Weight
GWh/yr	Gigawatt hours per year
H+	Hydrogen ion
H2O	Water
H2S	Hydrogen Sulfide
H2SO4	Sulfuric Acid
HAP(s)	Hazardous Air Pollutants
HC(s)	Hydrocarbons
HF	Hydrogen Fluoride
Hg	Mercury
HCHO	Formaldehyde
HNO3	Nitric Acid
hp	Horsepower
HRSG	Heat Recovery Steam Generator
HRVOC(s)	Highly Reactive Volatile Organic Compounds
I&M	Inspection and Maintenance
IBEMP	Innovation Technology and Best Energy-Environment Management Practices
ICE	Internal Combustion Engine
IGCC	Integrated Gasification Combined Cycle
IMPROVE	Interagency Monitoring of Protected Visual Environment
ISA	Instrument Systems and Automation Society
ISCST3	Industrial Source Complex – Short Term Dispersion Model, Version 3
IWAQM	Inter-Agency Work Group on Air Quality Modeling
K	One Thousand Dollars or Potassium
kg/ha-yr	Kilograms per Hectare-Year
km	kilometer
Kwh	kilowatt hour
LAER	Lowest Achievable Emission Rate
lb	pound
lbs/mmBtu	pounds of emissions/million btu heat input
lbs/MWh	pounds of emission/Megawatt-hour
LDAR	Leak Detection and Repair
LEED	Leadership in Energy Efficiency and Design
LiCl	Lithium Chloride
LIDAR	Light Detection and Ranging
LLC	Limited Liability Company
LNC	Lean NOX Catalyst
LNG	Liquefied Natural Gas
LoTOx	Low Temperature Oxidation Technology
LP	Limited Partnership
LPG	Liquefied Petroleum Gas
LTO	Low Temperature Oxidation
LWV	League of Women Voters
MACT	Maximum Achievable Control Technology
MC	Multi-Contact
mcf	one thousand cubic feet
MDN	Mercury Deposition Network
Mg	Magnesium
mg/L	milligrams per liter
mg/m3	micrograms per cubic meter
microg/g	micrograms per gram
MIT	Massachusetts Institute of Technology
MM	One Million Dollars
Mm^{-1}	Inverse Megameters
mmBtu	One Million British Thermal Units

MMcf/day	million cubic feet per day
MMscf/day	million standard cubic feet per day
MMV	Measurement, Monitoring and Verification Techniques
MOA	Memorandum of Agreement
MOU	Memorandum of Understanding
mph	Miles Per Hour
MPO	Metropolitan Planning Organization
MSI	Mountain Studies Institute
MW	Megawatt
N	Nitrogen
N2	Nitrogen gas
N2O	Nitrous Oxide
N2O3	Nitrogen Oxide
N2O5	Nitric Pentoxide
NA	Not Applicable
Na	Sodium
NAAQS	National Ambient Air Quality Standard
NADP	National Atmospheric Deposition Program
NEG	Net Excess Generation
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NGL	natural gas liquids
NH3	Ammonia
NI	no information
NM	New Mexico
NMED-AQB	New Mexico Environment Department-Air Quality Bureau
NMEMNRD	New Mexico Energy, Minerals and Natural Resources Department
NMHC	Non-Methane Hydrocarbon
NMOC	Non-Methane Organic Compounds
NMOCD	New Mexico Oil Conservation Division
NMOG	Non-Methane Organic Gas
NMOGA	New Mexico Oil and Gas Association
NMRPC	New Mexico Public Regulation Commission
NMUSA	New Mexico Utility Shareholders Alliance
NNEPA	Navajo Nation Environmental Protection Agency
No.	Number
NO	Nitric Oxide
NO2	Nitrogen Dioxide
NO3	Nitrate
NOx	Nitrogen Oxides
NOx/mmBtu	Nitrogen Oxides per million British Thermal Units
NOAA	National Oceanic & Atmospheric Administration
NP	National Park
NPS	National Park Service
NPV	Net Present Value
NRDC	Natural Resources Defense Council
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standards
NSR	New Source Review
NTN	National Trends Network
NW	Northwest
NWS	National Weather Service
NYCRR	New York Codes, Rules and Regulations
O&M	Operation and Maintenance
O2	Oxygen

O3	Ozone
OCD	Oil Conservation Division
OCV	Open Crankcase Ventilation
OECA	Office of Enforcement and Compliance Assurance
OH	Hydroxide
ONG	Onshore Natural Gas
OP-FTIR	Open-Path Fourier Transform Infrared
Oz	Ounce
PAH(s)	Polycyclic Aromatic Hydrocarbon
PC	Pulverized Coal
P/H	Power to Heat Ratio
pH	Acidity Measurement Unit
PLC	Programmable Logic Controller
PM	Particulate Matter
PM_{10}	Particulate Matter (effective diameter < 10 micrograms)
$PM_{2.5}$	Fine Particulate Matter (effective diameter < 2.5 micrograms)
POWID	Power Industry Division
ppb	parts per billion
ppm	parts per million
PRO	Partner Reported Opportunities
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PSNM	Public Service of New Mexico
PV	Photovoltaic
QA	Quality Assurance
QC	Quality Control
R&D	Research and Development
RACM	Reasonably Available Control Measures
RACT	Reasonably Available Control Technology
RAWS	Remote Automated Weather Stations
RC&D	Resource Conservation and Development
RE	Renewable Energy
REC(s)	Renewable Energy Credit
RH	Relative Humidity
RIA	Regulatory Impact Analyses
RICE	Reciprocating Internal Combustion Engine
RMP	Resource Management Plan
RMPPA	Resource Management Plan Planning Area
ROD	Record of Decision
ROG	Reactive Organic Gas
ROI	Return on Investment
RPM	Revolutions Per Minute
RPS	Renewable Portfolio Standards
RRC	Rebecca Reynolds Consulting
RVP	Reid Vapor Pressure
S	Sulfur
SAR	Specific Absorption Rate
scfh	standard cubic feet per hour of gas flow
SC	Supercritical
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SEP(s)	Supplemental Energy Payment
SI	Spark-Ignition Engine
SIP	State Implementation Plan

SJ	San Juan
SJGS	San Juan Generating Station
SLAMS	State/Local Air Monitoring Stations
SNCR	Selective Non-Catalytic Reduction
SO2	Sulfur Dioxide
SO2/mmBtu	Sulfur Dioxide/one million British Thermal Units
SOTA	State of the Art
SOx	Sulfur Oxides
SPMS	Special Purpose Monitoring Stations
sq mi	Square Miles
SRI	Southern Research Institute
SRP	Salt River Project Agricultural Improvement and Power District
SUIT	Southern Ute Indian Tribe
SW	Southwest
SWD	Salt Water Disposal Well
SWEEP	Southwest Energy Efficiency Project
TAG	Technical Assessment Guide
TBD	To Be Determined
TDLAS	Tunable Diode Laser Absorption Spectroscopy
TDS	Total Dissolved Solids
TEG	Triethylene Glycol
TF	Task Force
THC	Total Hydrocarbons
TPH	Total Petroleum Hydrocarbons
tpy	tons per year
TSD	technical support document
U.S.C.	United States Code
ULSD	Ultra Low Sulfur Diesel
US	United States
USC	Ultra Supercritical Coal
USCPC	Ultra-Supercritical Pulverized Coal
USDA	U.S. Department of Agriculture
USDI	U.S. Department of the Interior
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
UST	Underground Storage Tank
UT	Utah
VISTAS	Voluntary Innovative Strategies for Today’s Air Standards Program
VLUA	Vallecito Land Use Association
VMT	Vehicle Miles Traveled
VOC(s)	Volatile Organic Compounds
VRM	Visual Resource Management
VRP	Visibility Reducing Particles
VRU	Vapor Recovery Unit
vs.	Versus
W	West
W/m2	Watts per square meter
W/O	without
WDEQ	Wyoming Department of Environmental Quality
WESTAR	Western States Air Resource Council
WRAP	Western Regional Air Partnership

Definitions

Definitions

3-way catalyst: A catalyst containing both reduction and oxidation catalyst materials that converts Oxides of Nitrogen (NO_X), Carbon Monoxide (CO), and Non-Methane Hydrocarbons (NMHCs) to Nitrogen (N_2), Carbon Dioxide (CO_2), and water H_2O.

AP-42: An U.S. EPA compendium of emission factors for different source types. An emission factor is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. These factors are usually expressed as the weight of pollutant divided by a unit weight, volume, distance, or duration of the activity emitting the pollutant (e. g., kilograms of particulate emitted per megagram of coal burned). For additional information, see EPA's website at http://www.epa.gov/ttn/chief/ap42/.

Absorption: The process by which the energy of a photon is taken up by another entity.

Acid Deposition: A comprehensive term for the various ways acidic compounds precipitate from the atmosphere and deposit onto surfaces. It can include: 1) wet deposition by means of acid rain, fog, and snow; and 2) dry deposition of acidic particles (aerosols).

Acid Rain: Rain which is especially acidic (pH <5.2). Principal components of acid rain typically include nitric and sulfuric acid. These may be formed by the combination of nitrogen and sulfur oxides with water vapor in the atmosphere.

Acid Rain Program: The overall goal of the Acid Rain Program is to achieve significant environmental and public health benefits through reductions in emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx)—the primary causes of acid rain. To achieve this goal at the lowest cost to society, the program employs both traditional and innovative, market-based approaches for controlling air pollution. In addition, the program encourages energy efficiency and pollution prevention.

Activated Carbon Injection (ACI) Technology: In ACI technology, powdered activated carbon (PAC) sorbent is injected into the flue gas at a location in the duct preceding the particulate matter (PM) control device, which usually is an electrostatic precipitator or a fabric filter. The PAC sorbent binds with the mercury in the flue gas in the duct and in the PM control device. Subsequently, the mercury-containing PAC is captured in the PM control device.
Carbon Capture and Sequestration (CCS): Carbon capture and storage is an approach to mitigating climate change by capturing carbon dioxide (CO2) from large point sources such as power plants and subsequently storing it away safely instead of releasing it into the atmosphere. Technology for capturing of CO2 is already commercially available for large CO2 emitters, such as power plants. Storage of CO2, on the other hand, is a relatively untried concept and as yet (2007) no power plant operates with a full carbon capture and storage system. Currently, the United States government has approved the construction of the world's first CCS power plant, FutureGen, while BP has indicated that it intends to develop a 350 MW carbon capture and storage plant in Scotland, in which the carbon from a natural gas fired generator plant will be stripped out and pumped into the Miller field in the North Sea.

Add-On Control Device: An air pollution control device such as carbon absorber or incinerator that reduces the pollution in exhaust gas. The control device usually does not affect the process being controlled and thus is "add-on" technology, as opposed to a scheme to control pollution through altering the basic process itself. See also pollution prevention.

Adsorber: An emissions control device that removes volatile organic compounds (VOCs) from a gas stream as a result of the gas attaching (adsorbing) onto a solid matrix such as activated carbon.

Adsorption (Physical and Chemical): capability of all solid substances to attract to their surfaces molecules of gases or solutions with which they are in contact. Solids that are used to adsorb gases or dissolved substances are called adsorbents; the adsorbed molecules are usually referred to collectively as the adsorbate. An example of an excellent adsorbent is the charcoal used in gas mask.

Adverse Health Effect: A health effect from exposure to air contaminants that may range from relatively mild temporary conditions, such as eye or throat irritation, shortness of breath, or headaches to permanent and serious conditions, such as birth defects, cancer or damage to lungs, nerves, liver, heart, or other organs.

Aerosol: Particles of solid or liquid matter that can remain suspended in air from a few minutes to many months depending on the particle size and weight.

Afterburner: An air pollution abatement device that removes undesirable organic gases through incineration.

Agricultural Burning: The intentional use of fire for vegetation management in areas such as agricultural fields, orchards, rangelands, and forests.

Air: So called "pure" air is a mixture of gases containing about 78 percent nitrogen; 21 percent oxygen; less than 1 percent of carbon dioxide, argon, and other gases; and varying amounts of water vapor. See also ambient air.

Air Monitoring: Sampling for and measuring of pollutants present in the atmosphere.

Air Pollutants: Amounts of foreign and/or natural substances occurring in the atmosphere that may result in adverse effects to humans, animals, vegetation, and/or materials. (See also air pollution.)

Air Pollution: Degradation of air quality resulting from unwanted chemicals or other materials occurring in the air. (See also air pollutants.)

Air Quality Index (AQI): A numerical index used for reporting severity of air pollution levels to the public. The AQI incorporates five criteria pollutants -- ozone, particulate matter, carbon monoxide, sulfur dioxide, and nitrogen dioxide -- into a single index. The new index also incorporates the 8-hour ozone standard and the 24-hour $PM_{2.5}$ standard into the index calculation. AQI levels range from 0 (Good air quality) to 500 (Hazardous air quality). The higher the index, the higher the level of pollutants and the greater the likelihood of health effects. The AQI incorporates an additional index category -- unhealthy for sensitive groups -- that ranges from 101 to 150. In addition, the AQI comes with more detailed cautions.

Air Quality Model: A mathematical relationship between emissions and air quality which simulates on a computer the transport, dispersion, and transformation of compounds emitted into the air.

Air Quality Standard (AQS): The prescribed level of a pollutant in the outside air that should not be exceeded during a specific time period to protect public health. Established by both federal and state governments. (See also ambient air quality standards.)

Air separation membranes: Change the proportion of nitrogen to oxygen in air. A membrane can be optimized to either enrich the oxygen content or to enrich the nitrogen content.

Airshed: Denotes a geographical area that shares the same air because of topography, meteorology, and climate.

Air to Fuel Ratio Controller (AFRC): Device using a closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

Air Toxics: A generic term referring to a harmful chemical or group of chemicals in the air. Substances that are especially harmful to health, such as those considered under U.S. EPA's hazardous air pollutant program, are considered to be air toxics. Technically, any compound that is in the air and has the potential to produce adverse health effects is an air toxic.

Alcohol Fuels: Alcohol can be blended with gasoline for use as transportation fuel. It may be produced from a wide variety of organic feedstock. The common alcohol fuels are methanol and ethanol. Methanol may be produced from coal, natural gas, wood and organic waste. Ethanol is commonly made from agricultural plants, primarily corn, containing sugar.

Alkane: Chemical compounds that consist only of the elements carbon (C) and hydrogen (H) (i.e. hydrocarbons), where each of these atoms are linked together exclusively by single bonds.

Alternative Fuels: Fuels such as methanol, ethanol, natural gas, and liquid petroleum gas that are cleaner burning and help to meet mobile and stationary emission standards. These fuels may be used in place of less clean fuels for powering motor vehicles.

Ambient Air: The air occurring at a particular time and place outside of structures. Often used interchangeably with "outdoor air." (See also air.)

Ambient Air Quality Standards (AAQS): Health- and welfare-based standards for outdoor air which identify the maximum acceptable average concentrations of air pollutants during a specified period of time. (See also NAAQS and Criteria Air Pollutant.)

American Society for Testing and Materials (ASTM): A nonprofit organization that provides a forum for producers, consumers, and representatives of government and industry, to write laboratory test standards for materials, products, systems, and services. ASTM publishes standard test methods, specifications, practices, guides, classifications, and terminology.

Amines: Amines are organic compounds that contain nitrogen as the key atom. Structurally, amines resemble ammonia. The advantage of an amine CO_2 removal system is that it has a lower capital cost than any of the current physical solvent processes. The disadvantage is that an amine system uses large amounts of steam heat for solvent regeneration and energy to re-cool the amine, making it a less energy efficient process**.**

Ammonia (NH_3): A pungent colorless gaseous compound of nitrogen and hydrogen that is very soluble in water and can easily be condensed into a liquid by cold and pressure. Ammonia reacts with NOx to form ammonium nitrate -- a major $PM_{2.5}$ component in the Western United States.

Ammonia slip: Ammonia emissions from SCR systems.

Area Sources: Those sources for which a methodology is used to estimate emissions. This can include area-wide, mobile and natural sources, and also groups of stationary sources (such as dry cleaners and gas stations). Sources which are not reported as individual point sources are included as area sources. The federal air toxics program defines a source that emits less than 10 tons per year of a single hazardous air pollutant (HAP) or 25 tons per year of all HAPs as an area source.

Aromatic compounds: An organic chemical compound that contains aromatic rings (arenes) like benzene, pyridine, or indole and possessing an aroma, fragrance, flavor, smell, or odor

Asthma: A chronic inflammatory disorder of the lungs characterized by wheezing, breathlessness, chest tightness, and cough.

Atmosphere: The gaseous mass or envelope of air surrounding the Earth. From ground-level up, the atmosphere is further subdivided into the troposphere, stratosphere, mesosphere, and the thermosphere.

Attainment Area: A geographical area identified to have air quality as good as, or better than, the national ambient air quality standards (NAAQS). An area may be an attainment area for one pollutant and a nonattainment area for others.

Baghouse: An air pollution control device that traps particulates by forcing gas streams through large permeable bags usually made of glass fibers.

Banking: A provision used in emissions trading programs that allows a facility to accumulate credits for reducing emissions beyond regulatory limits (emission reduction credits) and then use or sell those credits at a later date.

Baseline: A starting point or condition against which future changes are measured. For air quality emissions, the known emissions in a given year that future emissions can be measured against.

Benzene, Toluene, Ethyl Benzene, Xylene (BTEX): Group of volatile organic compounds (VOCs) found in petroleum hydrocarbons, such as gasoline, and other common environmental contaminants.

Best Available Control Measure (BACM): A term used to describe the "best" measures (according to U.S. EPA guidance) for controlling small or dispersed sources of particulate matter and other emissions from sources such as roadway dust, woodstoves, and open burning.

Best Available Control Technology (BACT): The most up-to-date methods, systems, techniques, and production processes available to achieve the greatest feasible emission reductions for given regulated air pollutants and processes. BACT is a requirement of NSR (New Source Review) and PSD (Prevention of Significant Deterioration).

Best Available Retrofit Technology (BART): An air emission limitation that applies to existing sources and is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source. (See also Best Available Control Technology.)

Bioenergy: Useful, renewable energy produced from organic matter, which may either be used directly as a fuel or processed into liquids and gases.

Biofuels: Liquid fuels and blending components produced from biomass (plant) feedstocks, used primarily for transportation.

Biogenic Source: Biological sources such as plants and animals that emit air pollutants such as volatile organic compounds. Examples of biogenic sources include animal management operations, and oak and pine tree forests. (See also natural sources.)

Biomass: Organic nonfossil matter of a biological origin available on a renewable basis. Biomass includes forest and mill residues, agricultural crops and wastes, wood and wood wastes, animal wastes, livestock operation residues, aquatic plants, fast-growing trees and plants, and municipal and industrial wastes.

Boiler: A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. A device where heat converts water to steam.

Carbon (CO2) Capture and Storage: CO2 capture and storage involves capturing the CO2 arising from the combustion of fossil fuels, as in power generation, or from the preparation of fossil fuels, as in natural-gas processing. Capturing CO2 involves separating the CO2 from some other gases. For example in the exhaust gas of a power plant other gases would include nitrogen and water vapor. The CO2 must then be transported to a storage site where it will be stored away from the atmosphere for a long period of time. In order to have a significant effect on atmospheric concentrations of CO2, storage reservoirs would have to be large relative to annual emissions. (IPCC, 2001). Sometimes referred to as sequestration.

Carbon Dioxide (CO_2): A colorless, odorless gas that occurs naturally in the Earth's atmosphere. Significant quantities are also emitted into the air by fossil fuel combustion.

Carbon mass balance: An accounting of material entering and leaving a system.

Carbon Monoxide (CO): A colorless, odorless gas resulting from the incomplete combustion of hydrocarbon fuels. CO interferes with the blood's ability to carry oxygen to the body's tissues and results in numerous adverse health effects. CO is a criteria air pollutant.

Carcinogen: A cancer-causing substance. (See also cancer.)

CAS Registry Number: The Chemical Abstracts Service Registry Number (CAS) is a numeric designation assigned by the American Chemical Society's Chemical Abstract Service and uniquely identifies a specific compound. This entry allows one to conclusively identify a material regardless of the name or naming system used.

Catalyst: A substance that can increase or decrease the rate of a chemical reaction between the other chemical species without being consumed in the process.

Catalyst Deactivation: Poisoning is a primary factor in deactivation, with blockage and physical destruction of equal importance to catalyst life. When the surface or pores of the catalyst are blocked, flue gas/NOx cannot contact the catalyst.

Catalytic converter: The mechanism by which the catalyst will either oxidize (oxidation catalyst) a CO or fuel molecule or reduce (reduction catalyst) a NO_X molecule.

Cation: A positively-charged ion, which has fewer electrons than protons. An ion is an atom or group of atoms which have lost or gained one or more electrons, making them negatively or positively charged.

Cell Burner: Cell burner boiler means a wall-fired boiler that utilizes two or three circular burners combined into a single vertically oriented assembly that results in a compact, intense flame. Cell burner boilers have closely spaced clusters of two or three burners (i.e., cells) that together result in a single flame. In addition, the boilers are, like many wall-fired boilers, relatively compactly designed with small furnaces.

Chromatography: A set of laboratory techniques for separation of mixtures. One such procedure includes passing a mixture dissolved in a "mobile phase" through a stationary phase, which separates the analyte to be measured from other molecules in the mixture and allows it to be isolated.

Chronic Exposure: Long-term exposure, usually lasting one year to a lifetime.

Chronic Health Effect: A health effect that occurs over a relatively long period of time (e.g., months or years). (See also acute health effect.)

Class I Area: Under the Clean Air Act, a Class I area is one in which visibility is protected more stringently than under the national ambient air quality standards; includes national parks, wilderness area, monuments and other areas of special national and cultural significance.

Clean Air Act (CAA): A federal law passed in 1970 and amended in 1974, 1977 and 1990 which forms the basis for the national air pollution control effort. Basic elements of the act include national ambient air quality standards for major air pollutants, mobile and stationary control measures, air toxics standards, acid rain control measures, and enforcement provisions.

Clean Air Mercury Rule: On March 15, 2005, EPA issued the Clean Air Mercury Rule to permanently cap and reduce mercury emissions from coal-fired power plants for the first time ever. This rule makes the United States the first country in the world to regulate mercury emissions from utilities.

Cleaner-Burning Gasoline: Gasoline fuel that results in reduced emissions of carbon monoxide, nitrogen oxides, reactive organic gases, and particulate matter, in addition to toxic substances such as benzene and 1,3-butadiene.

Coal bed methane (CBM): Methane found in coal seams.

Code of Federal Regulations (CFR): The codification of the general and permanent rules published in the Federal Register by the executive departments and agencies of the Federal Government pursuant to authority derived from the Clean Air, Water, and other environmental acts.

Cogeneration: See combined heat and power.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. Such designs increase the efficiency of the electric generating unit.

Combined Heat and Power (CHP) Plant: A plant designed to produce both heat and electricity from a single heat source. Note: This term is being used in place of the term "cogenerator" that was used by EIA in the past. CHP better describes the facilities because some of the plants included do not produce heat and power in a sequential fashion and, as a result, do not meet the legal definition of cogeneration specified in the Public Utility Regulatory Policies Act (PURPA).

Combustion: The act or instance of burning some type of fuel such as gasoline to produce energy. Combustion is typically the process that powers automobile engines, oil and gas-field engines, and power plant generators.

Compressed natural gas (CNG): A substitute for gasoline (petrol) or diesel fuel, made by compressing methane extracted from natural gas.

Concentrator: A reflective or refractive device that focuses incident insolation onto an area smaller than the reflective or refractive surface, resulting in increased insolation at the point of focus.
Conventional hydroelectric (hydropower) plant: A plant in which all of the power is produced from natural streamflow as regulated by available storage.

Condensate tank: Tank for storing condensate from oil and gas activity.

Condensate Tank Battery: Comprised of a single storage tank or a group of storage tanks with a design capacity less than or equal to 10,000 barrels per tank, used for the storage of condensate and located at an exploration and production facility.

Consent Decree: When a court case has been filed, the parties can resolve the case short of having a trial by entering into a joint agreement or by consenting to a judgment.

Continuous Emission Monitor (CEM): A type of air emission monitoring system installed to operate continuously inside of a smokestack or other emission source.

Continuous Sampling Device: An air analyzer that measures air quality components continuously. (See also Integrated Sampling Device.)

Control Techniques Guidelines (CTG): Guidance documents issued by U.S. EPA that define reasonably available control technology (RACT) to be applied to existing facilities that emit excessive quantities of air pollutants; they contain information both on the economic and technological feasibility of available techniques.

Cost-Effectiveness: The cost of an emission control measure assessed in terms of dollars-per-pound, or dollars-per-ton, of air emissions reduced.

Criteria Air Pollutant: An air pollutant for which acceptable levels of exposure can be determined and for which an ambient air quality standard has been set. Examples include: ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, and PM_{10} and $PM_{2.5}$. The term "criteria air pollutants" derives from the requirement that the U.S. EPA must describe the characteristics and potential health and welfare effects of these pollutants. The U.S. EPA periodically reviews new scientific data and may propose revisions to the standards as a result.

Cryogenic: production of very low temperatures and the behavior of materials at those temperatures below -150C.

Cyclone: An air pollution control device that removes larger particles -- generally greater than one micron -- from an air stream through centrifugal force.

Deciview: A measurement of visibility. One deciview represents the minimal perceptible change in visibility to the human eye.

Desiccant dehydrator: Device that uses moisture-absorbing salts to remove water from natural gas. In general, there are only minor air emissions from desiccant systems.

Diesel Engine: A type of internal combustion engine that uses low-volatility petroleum fuel and fuel injectors and initiates combustion using compression ignition (as opposed to spark ignition that is used with gasoline engines).

Diesel fuel emulsion: Emulsion of diesel and other fuel intended to reduce peak engine combustion temperatures and increase fuel atomization and combustion efficiency.

Diesel oxidation catalyst (DOC): Device that uses a chemical process to break down pollutants in the exhaust stream into less harmful components. Diesel oxidation catalysts can reduce emissions of particulate matter (PM) by 20% and hydrocarbons (HC) by 50% and carbon monoxide (CO) by approximately 40%.

Diesel particulate filter: Filter that collects or traps particulate matter (PM) in the exhaust.

Diffraction: Diffraction refers to various phenomena associated with wave propagation, such as the bending, spreading and interference of waves such as visible light.

Dispersion Model: See air quality model above.

Distributed Generation (Distributed Energy Resources): Refers to electricity provided by small, modular power generators (typically ranging in capacity from a few kilowatts to 50 megawatts) located at or near customer demand.

Dose: The amount of a pollutant that is absorbed. A level of exposure which is a function of a pollutant's concentration, the length of time a subject is exposed, and the amount of the pollutant that is absorbed. The concentration of the pollutant and the length of time that the subject is exposed to that pollutant determine dose.

Dose-Response: The relationship between the dose of a pollutant and the response (or effect) it produces on a biological system.

Drill rig: General term used to describe a wide variety of machines that create holes (usually called boreholes) and/or shafts in the ground, or to install wells.

Dry-bottom, Wall-fired: Dry bottom means the boiler has a furnace bottom temperature below the ash melting point and the bottom ash is removed as a solid. Wall-fired boiler means a boiler that has pulverized coal burners arranged on the walls of the furnace. The burners have discrete, individual flames that extend perpendicularly into the furnace area.

Dry Cooled Coal-Fired: Dry cooling operates without evaporation by passing the steam from the turbines through a set of finned pipes immediately beside the turbine and cooling the water by having large volumes of air driven by fans to condense the steam in the pipes.

Dust: Solid particulate matter that can become airborne.

Ecosystem: A self-sustaining association of plants, animals, and the physical environment in which they live.

Electric Generating Unit (EGU) – Clean Air Interstate Rule definition:
(a) Except as provided in paragraph (b) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil fuel fired combustion turbine serving at any time, since the start-up of a unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.
(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of

the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public. Included are investor-owned electric utilities, municipal and State utilities, Federal electric utilities, and rural electric cooperatives. A few entities that are tariff based and corporately aligned with companies that own distribution facilities are also included.

Electrostatic Precipitator (ESP): An air pollution control device that removes particulate matter from an air stream by imparting an electrical charge to the particles for mechanical collection at an electrode.

Emission Factor: For stationary sources, the relationship between the amount of pollution produced and the amount of raw material processed or burned. For mobile sources, the relationship between the amount of pollution produced and the number of vehicle miles traveled. By using the emission factor of a pollutant and specific data regarding quantities of materials used by a given source, it is possible to compute emissions for the source. This approach is used in preparing an emissions inventory.

Emission Inventory: An estimate of the amount of pollutants emitted into the atmosphere from major mobile, stationary, area-wide, and natural source categories over a specific period of time such as a day or a year.

Emission Rate: The weight of a pollutant emitted per unit of time (e.g., tons / year).

Emission Standard: The maximum amount of a pollutant that is allowed to be discharged from a polluting source such as an automobile or smoke stack.

Emission trading system (ETS): Program wherein the governing authority (e.g., agency) issues a limited number of allocations in the form of certificates consistent with the desired or targeted level of emissions in an identified region or area. The sources of a particular air pollutant (e.g., NOx) are allotted certificates to release a specified number of tons of the pollutant. The certificate owners may choose either to continue to release the pollutant at current levels and use the certificates or to reduce their emissions and sell the certificates.

Enardo valve: Brand name for a pressure relief valve installed on condensate and other oil storage tanks to control evaporation and fugitive emission losses that result from flammable and hazardous petroleum vapor-producing products.

Energy Content: The amount of energy available for doing work. For example, the amount of energy in fuel available for powering a motor vehicle.

Energy Crops: Crops grown specifically for their fuel value. These include food crops such as corn and sugarcane, and nonfood crops such as poplar trees and switchgrass. Currently, two energy crops are under development: short - rotation woody crops, which are fast - growing hardwood trees harvested in five to eight years, and herbaceous energy crops, such as perennial grasses, which are harvested annually after taking two to three years to reach full productivity.

Energy Efficiency: Energy efficiency refers to products or systems using less energy to do the same or better job than conventional products or systems. Energy efficiency saves energy, saves money on utility bills, and helps protect the environment by reducing the amount of electricity that needs to be generated. When buying or replacing products or appliances for your home, look for the ENERGY STAR® label — the national symbol for energy efficiency. For more information on ENERGY STAR® labeled products, visit the ENERGY STAR® Web site.

Enhanced Gas Recovery and/or Enhanced Coal Bed Methane Recovery: To enhance coal bed methane recovery factors and production rates as a result of CO2 injection.
Burlington Resources has successfully injected CO2 into relatively high permeability coalbeds in the San Juan basin in the USA for several years. They are stimulating coalbed methane production and recovery. The injected CO2 is

adsorbed into the coal matrix and remains in the ground after completion of gas production. However, further testing and demonstration are needed to apply this process to low permeability reservoirs.

Enhanced Oil Recovery: Using CO_2 injection to enhance production from oil reservoirs.

Environmental Justice: The fair treatment of people of all races and incomes with respect to development, implementation, and enforcement of environmental laws, regulations, and policies.

EPA's Natural Gas STAR Program: The Natural Gas STAR Program is a flexible, voluntary partnership between U.S. EPA and the oil and natural gas industry. Through the program, U.S. EPA works with companies that produce, process, and transmit and distribute natural gas to identify and promote the implementation of cost-effective technologies and practices to reduce emissions of methane, a potent greenhouse gas.

Ethanol (also known as Ethyl Alcohol or Grain Alcohol, CH3-CH2OH): A clear, colorless flammable oxygenated hydrocarbon with a boiling point of 173.5 degrees Fahrenheit in the anhydrous state. However it readily forms a binary azetrope with water, with a boiling point of 172.67 degrees Fahrenheit at a composition of 95.57 percent by weight ethanol. It is used in the United States as a gasoline octane enhancer and oxygenate (maximum 10 percent concentration). Ethanol can be used in higher concentrations (E85) in vehicles designed for its use. Ethanol is typically produced chemically from ethylene, or biologically from fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. The lower heating value, equal to 76,000 Btu per gallon, is assumed for estimates in this report.

Evacuated Tube: In a solar thermal collector, an absorber tube, which is contained in an evacuated glass cylinder, through which collector fluids flows.

Evaporative Emissions: Emissions from evaporating gasoline, which can occur during vehicle refueling, vehicle operation, and even when the vehicle is parked. Evaporative emissions can account for two-thirds of the hydrocarbon emissions from gasoline-fueled vehicles on hot summer days.

Exhaust Gas Recirculation (EGR): An emission control method that involves recirculating exhaust gases from an engine back into the intake and combustion chambers. This lowers combustion temperatures and reduces NOx. (See also nitrogen oxides.)

Exceedance: A measured level of an air pollutant higher than the national or state ambient air quality standards. (See also NAAQS.)

Federal Implementation Plan (FIP): In the absence of an approved State Implementation Plan (SIP), a plan prepared by the U.S. EPA which provides measures that areas must take to meet the requirements of the Federal Clean Air Act.

Feedstock: The raw material that is required for some industrial process.

Flaring: Technique of igniting hydrocarbon gases to convert natural gas constituents (hydrocarbons, including BTEX and other Hazardous Air Pollutants) into less hazardous and atmospherically reactive compounds.

Flash emissions: Emissions resulting by a reduction in pressure and/or temperature when hydrocarbon liquids are dumped into the storage tank from the production separator.

Flow through filters (FTF): Filters for capture or oxidize particles, using a variety of media and regeneration strategies. The filter media can be either wire mesh or pertubated path metal foil.

Flue gas: Exhaust gases following combustion.

Fly Ash: Air-borne solid particles that result from the burning of coal and other solid fuel.

Fossil Fuels: Fuels such as coal, oil, and natural gas; so-called because they are the remains of ancient plant and animal life.

Fugitive Dust: Dust particles that are introduced into the air through certain activities such as soil cultivation, or vehicles operating on open fields or dirt roadways. A subset of fugitive emissions.

Fugitive Emissions: Emissions not caught by a capture system which are often due to equipment leaks, evaporative processes and windblown disturbances.

Furnace: A combustion chamber; an enclosed structure in which fuel is burned to heat air or material.

FutureGen: FutureGen is a project of the US government to build a near zero-emissions coal-fueled power plant that intends to produce hydrogen and electricity while using carbon capture and storage.

Gas Turbine: An engine that uses a compressor to draw air into the engine and compress it. Fuel is added to the air and combusted in a combustor. Hot combustion gases exiting the engine turn a turbine which also turns the compressor. The engine's power output can be delivered from the compressor or turbine side of the engine.

Gasifier: A device for converting solid fuel into gaseous fuel.

Generation (Electricity): The process of producing electric energy from other forms of energy; also, the amount of electric energy produced, expressed in watthours (Wh).

Global Warming: An increase in the temperature of the Earth's troposphere. Global warming has occurred in the past as a result of natural influences, but the term is most often used to refer to the warming predicted by computer models to occur as a result of increased emissions of greenhouse gases.

GLYCALC: A software program for estimating air emissions from glycol units using triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

Glycol dehydrator: Any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water from the natural gas stream.

Green Power: Electricity that is generated from renewable energy sources is often referred to as "green power." Green power products can include electricity generated exclusively from renewable resources or, more frequently, electricity produced from a combination of fossil and renewable resources. Also known as "blended" products, these products typically have lower prices than 100 percent renewable products. Customers who take advantage of these options usually pay a premium for having some or all of their electricity produced from renewable resources. To find out more about green power, visit EPA's Green Power Partnership Web site.

Greenhouse Effect: The warming effect of the Earth's atmosphere. Light energy from the sun which passes through the Earth's atmosphere is absorbed by the Earth's surface and re-radiated into the atmosphere as heat energy. The heat energy is then trapped by the atmosphere, creating a situation similar to that which occurs in a car with its windows rolled up. A number of scientists believe that the emission of CO_2 and other gases into the atmosphere may increase the greenhouse effect and contribute to global warming.

Greenhouse Gases: Atmospheric gases such as carbon dioxide, methane, chlorofluorocarbons, nitrous oxide, ozone, and water vapor that slow the passage of re-radiated heat through the Earth's atmosphere.

Gypsum: Gypsum is one of the most widely used minerals in the world. Most gypsum in the United States is used to make wallboard for homes, offices, and commercial buildings; a typical new American home contains more than seven metric tons of gypsum alone. Moreover, gypsum is used worldwide in concrete for highways, bridges, buildings, and many other structures that are part of our everyday life. Gypsum also is used extensively as a soil conditioner on large tracts of land in suburban areas, as well as in agricultural regions.

Hazardous Air Pollutant (HAP): An air pollutant listed under section 112 (b) of the federal Clean Air Act as particularly hazardous to health. Emission sources of hazardous air pollutants are identified by U.S. EPA, and emission standards are set accordingly.

Haze (Hazy): A phenomenon that results in reduced visibility due to the scattering of light caused by aerosols. Haze is caused in large part by man-made air pollutants.

Health-Based Standard (Primary Standard): A dosage of air pollution scientifically determined to protect against human health effects such as asthma, emphysema, and cancer.

Heat Recovery Steam Generator (HRSG): Recovers waste heat exhaust from a combustion turbine and generates steam

"Hot Spot": (See toxic hot spot.)

Hydrated Lime Injection: Calcium hydroxide, also known as slaked lime, is a chemical compound with the chemical formula Ca(OH)2. It is a colorless crystal or white powder, and is obtained when calcium oxide (called lime or quicklime) is slaked with water. It can also be precipitated by mixing an aqueous solution of calcium chloride and an aqueous solution of sodium hydroxide. A traditional name for calcium hydroxide is slaked lime, or hydrated lime.
Hydrated lime may be injected into the upper regions of a furnace where high temperatures are conducive to driving the reaction between the calcium and SO2 to achieve up to 70% SO2 removal.

Hydrocarbons: Compounds containing various combinations of hydrogen and carbon atoms. They may be emitted into the air by natural sources (e.g., trees) and as a result of fossil and vegetative fuel combustion, fuel volatilization, and solvent use. Hydrocarbons are a major contributor to smog.

Hydrogen Sulfide (H_2S): A colorless, flammable, poisonous compound having a characteristic rotten-egg odor. It is used in industrial processes and may be emitted into the air.

Incentives: Subsidies and other Government actions where the Governments's financial assistance is indirect.

Incineration: The act of burning a material to ashes.

Indirect emissions: *See* Indirect Source.

Indirect Source: Any facility, building, structure, or installation, or combination thereof, which generates or attracts mobile source activity that results in emissions of any pollutant (or precursor) for which there is a state ambient air quality standard. Examples of indirect sources include employment sites, shopping centers, sports facilities, housing developments, airports, commercial and industrial development, and parking lots and garages.

Industrial Source: Any of a large number of sources -- such as manufacturing operations, oil and gas refineries, food processing plants, and energy generating facilities -- that emit substances into the atmosphere.

Inert Gas: A gas that does not react with the substances coming in contact with it.

Inert gas blanket: “Blanket” of inert (chemically non-reactive) gas that fills the space above the condensate/crude oil to minimize volatilization and vapor loss.

Injection wells: Well in which fluids are injected rather than produced, the primary objective typically being to maintain reservoir pressure. Two common types of injection gas and water. Separated gas from production wells or possibly imported gas may be reinjected into the upper gas section of the reservoir to maintain pressure.

Inspection and Maintenance (I&M) Program: A motor vehicle inspection program. The purpose of the I&M is to reduce emissions by assuring that cars are running properly. It is designed to identify vehicles in need of maintenance and to assure the effectiveness of their emission control systems on a biennial basis.

Integrated Sampling Device: An air sampling device that allows estimation of air quality components over a period of time through laboratory analysis of the sampler's medium.

Internal Combustion Engine: An engine in which both the heat energy and the ensuing mechanical energy are produced inside the engine. Includes gas turbines, spark ignition gas, and compression ignition diesel engines.

Inversion: A layer of warm air in the atmosphere that prevents the rise of cooling air and traps pollutants beneath it.

Kilowatt (kW): One thousand watts of electricity (See Watt).

Kilowatthour (kWh): One thousand watthours.

Kimray pump: Brand name of automated glycol pump used to circulate glycol in dehydrators.

Laser ignition: Ignition sequence replacing the conventional spark plugs with a laser beam that is focused to a point in the combustion chamber. There, the focused, coherent light ionizes the fuel-air mixture to initiate combustion.

Lead: A gray-white metal that is soft, malleable, ductile, and resistant to corrosion. Sources of lead resulting in concentrations in the air include industrial sources and crustal weathering of soils followed by fugitive dust emissions. Health effects from exposure to lead include brain and kidney damage and learning disabilities. Lead is the only substance which is currently listed as both a criteria air pollutant and a toxic air contaminant.

Leadership in Energy Efficiency and Design certification (LEED): The Leadership in Energy and Environmental Design (LEED) Green Building Rating System™ is the nationally accepted benchmark for the design, construction, and operation of high performance green buildings. LEED gives building owners and operators the tools they need to have an immediate and measurable impact on their buildings' performance. LEED promotes a whole-building approach to sustainability by recognizing performance in five key areas of human and environmental health: sustainable site development, water savings, energy efficiency, materials selection, and indoor environmental quality.

Leak Detection and Repair (LDAR): Leak detection protocol, using either Photo-ionization detectors or infrared cameras promises to prevent volatile organic compound and hazardous air pollutant emissions from leaking equipment.

Lean Burn Engine: An engine that employs a fuel mixture with a higher air content than fuel as regulated by the AFRC with a normal exhaust oxygen concentration of 2% by volume, or greater.

Liquid Natural Gas (LNG): Natural gas that has been processed to remove either valuable components (e.g. helium) or those impurities that could cause difficulty downstream (e.g. water and heavy hydrocarbons) and then condensed into a liquid.

Lowest Achievable Emission Rate (LAER): Under the Clean Air Act, the rate of emissions that reflects (1) the most stringent emission limitation in the State Implementation Plan of any state for a given source unless the owner or operator demonstrates such limitations are not achievable; or (2) the most stringent emissions limitation achieved in practice, whichever is more stringent.

Low NOx Burners: One of several combustion technologies used to reduce emissions of nitrogen oxides.

Major Source: A stationary facility that emits a regulated pollutant in an amount exceeding the threshold level depending on the location of the facility and attainment with regard to air quality status. (See Source.)

Mass Spectrometry: Analytical technique used to measure the mass-to-charge ratio of ions.

Maximum Achievable Control Technology (MACT): Federal emissions limitations based on the best demonstrated control technology or practices in similar sources to be applied to major sources emitting one or more federal hazardous air pollutants.

Mean: Average.

Median: The middle value in a population distribution, above and below which lie an equal number of individual values; midpoint.

Megawatt (MW): One million watts of electricity (See Watt).

Melting Point: The temperature at which a solid becomes a liquid. At this temperature, the solid and the liquid have the same vapor pressure.

Mercury: A chemical element in the periodic table that has the symbol Hg. A heavy, silvery transition metal, mercury is one of five elements that are liquid at or near room temperature and pressure.

Mercury Deposition Network (MDN): The objective of the MDN is to develop a national database of weekly concentrations of total mercury in precipitation and the seasonal and annual flux of total mercury in wet deposition. The data will be used to develop information on spatial and seasonal trends in mercury deposited to surface waters, forested watersheds, and other sensitive receptors. See http://nadp.sws.uiuc.edu/mdn/

Mercury (Hg) Speciation: Mercury can assume many forms and, through interactions with the environment, can be transformed into a variety of structures. The most commonly known forms of mercury include: Elemental Mercury, divalent mercury (mercuric chloride) and methyl mercury.
The behavior of mercury in the atmosphere depends upon its form, or specie. Elemental mercury (Hgo) is typically not very reactive with global lifetime of a few months to a year and is thought to be transported significantly in the troposphere. Reactive gaseous mercury (RGM) species, are not well characterized chemically but are thought to be gaseous Hg(II)-bearing molecules such as HgCl2(g). RGM species are notable for being quickly deposited from the atmosphere to the surface and are thought to be readily available for conversion to methylmercury, a highly toxic form of mercury. Particulate mercury (Hg-P) is also quickly deposited and is often found in high concentrations near combustion sources. Although much lower in proportion than Hgo, the greater reactivity and deposition rates of RGM and Hg-P make them a larger environment concern. Chemical reactions that occur in the atmosphere can transform mercury between these various species.

Mesosphere: The layer of the Earth's atmosphere above the stratosphere and below the thermosphere. It is between 35 and 60 miles from the Earth.

Methane: A chemical compound with the molecular formula CH_4. It is the simplest alkane, and the principal component of natural gas. Burning one molecule of methane in the presence of oxygen releases one molecule of CO_2 (carbon dioxide) and two molecules of H_2O. It is also an important source of hydrogen in various industrial processes. Methane is a greenhouse gas.

Methyl Mercury: Mercury in the air eventually settles into water or onto land where it can be washed into water. Once deposited, certain microorganisms can change it into methylmercury, a highly toxic form that builds up in fish, shellfish and animals that eat fish. Fish and shellfish are the main sources of methylmercury exposure to humans. Methylmercury builds up more in some types of fish and shellfish than others. The levels of methylmercury in fish and shellfish depend on what they eat, how long they live and how high they are in the food chain. Mercury exposure at high levels can harm the brain, heart, kidneys, lungs, and immune system of people of all ages. Research shows that most people's fish consumption does not cause a health concern. However, it has been demonstrated that high levels of methylmercury in the bloodstream of unborn babies and young children may harm the developing nervous system, making the child less able to think and learn.

Minor Source: Any stationary source that does not qualify as a major source and directly emits, or has the potential to emit, less than one hundred tons per year or more of any air pollutant.

Mobile Sources: Sources of air pollution such as automobiles, motorcycles, trucks, off-road vehicles, boats, and airplanes. (See also stationary sources).

Monitoring: The periodic or continuous sampling and analysis of air pollutants in ambient air or from individual pollution sources.

National Ambient Air Quality Standards (NAAQS): Standards established by the United States EPA that apply for outdoor air throughout the country. There are two types of NAAQS. Primary standards set limits to protect public health and secondary standards set limits to protect public welfare.

National Emission Standards for Hazardous Air Pollutants (NESHAPS): Emissions standards set by the U.S. EPA for a hazardous air pollutant, such as benzene, which may cause an increase in deaths or in serious, irreversible, or incapacitating illness.

Natural Sources: Non-manmade emission sources, including biological and geological sources, wildfires, and windblown dust.

Net Metering: Arrangement that permits a facility (using a meter that reads inflows and outflows of electricity) to sell any excess power it generates over its load requirement back to the electrical grid to offset consumption.

Neurotoxin: A toxin that acts specifically on nerve cells.

New Mexico Public Regulation Commission: The New Mexico Public Regulation Commission (PRC) regulates the utilities, telecommunications, motor carriers and insurance industries to ensure fair and reasonable rates, and to assure reasonable and adequate services to the public as provided by law.

New Source Performance Standards (NSPS): Uniform national EPA air emission standards that limit the amount of pollution allowed from new sources or from modified existing sources.

New Source Review (NSR): A Clean Air Act requirement that State Implementation Plans must include a permit review, which applies to the construction and operation of new and modified stationary sources in nonattainment areas, to ensure attainment of national ambient air quality standards. The two major requirements of NSR are Best Available Control Technology and Emission Offsets.

Nitrate (NO_3): A salt of nitric acid with an ion composed of one nitrogen and three oxygen atoms.

Nitric Oxide (NO): Precursor of ozone, NO_2, and nitrate; nitric oxide is usually emitted from combustion processes. Nitric oxide is converted to nitrogen dioxide (NO_2) in the atmosphere, and then becomes involved in the photochemical processes and / or particulate formation. (See Nitrogen Oxides.)

Nitrogen: Chemical element, which has the symbol N, and atomic number 7. Elemental nitrogen is a colorless, odorless, tasteless and mostly inert diatomic gas at standard conditions, constituting 78.1% by volume of Earth's atmosphere.

Nitrogen Enrichment Mode: NOx decreases while particulate emissions increase.

Nitrogen Oxides (Oxides of Nitrogen, NOx): A general term pertaining to compounds of nitric oxide (NO), nitrogen dioxide (NO_2) and other oxides of nitrogen. Nitrogen oxides are typically created during combustion processes, and are major contributors to smog formation and acid deposition. NO_2 is a criteria air pollutant, and may result in numerous adverse health effects.

Nonattainment Area: A geographic area identified by the U.S. EPA as not meeting the NAAQS for a given pollutant.

Noncarcinogenic Effects: Non-cancer health effects which may include birth defects, organ damage, morbidity, and death.

Non-Industrial Source: Any of a large number of sources -- such as mobile, area-wide, indirect, and natural sources -- which emit substances into the atmosphere.

Non-Methane Hydrocarbon (NMHC): The sum of all hydrocarbon air pollutants except methane. NMHCs are significant precursors to ozone formation.

Non-Methane Organic Gas (NMOG): The sum of non-methane hydrocarbons and other organic gases such as aldehydes, ketones and ethers.

Non-Point Sources: Diffuse pollution sources that are not recognized to have a single point of origin.

Non-Road Emissions: Pollutants emitted by a variety of non-road sources such as farm and construction equipment, gasoline-powered lawn and garden equipment, and power boats and outboard motors.

NOx Traps: Operate in a two-step cyclic process. In the first stage the NOx trap adsorbs NOx while the engine operates in a lean-burn mode. In the second stage, the engine operates with excess fuel in the exhaust. The fuel decomposes on the catalyst and reduces the NOx to molecular nitrogen and water.

O_2 enrichment mode: Produces a dramatic reduction in particulate emissions at the expense of increased NOx emissions.

Opacity: The amount of light obscured by particle pollution in the atmosphere. Opacity is used as an indicator of changes in performance of particulate control systems.

Organic Compounds: A large group of chemical compounds containing mainly carbon, hydrogen, nitrogen, and oxygen. All living organisms are made up of organic compounds.

Oxidant: A substance that brings about oxidation in other substances. Oxidizing agents (oxidants) contain atoms that have suffered electron loss. In oxidizing other substances, these atoms gain electrons. Ozone, which is a primary component of smog, is an example of an oxidant.

Oxidation: The chemical reaction of a substance with oxygen or a reaction in which the atoms in an element lose electrons and its valence is correspondingly increased.

Oxidation catalysts: Element using a catalytic conversion for control of hydrocarbon and CO emissions.

Oxygenate: An organic molecule that contains oxygen. Oxygenates are typically ethers and alcohols.

Ozone (O_3): A strong smelling, pale blue, reactive toxic chemical gas consisting of three oxygen atoms. It is a product of the photochemical process involving the sun's energy and ozone precursors, such as hydrocarbons and oxides of nitrogen. Ozone exists in the upper atmosphere ozone layer (stratospheric ozone) as well as at the Earth's surface in the troposphere (ozone). Ozone in the troposphere causes numerous adverse health effects and is a criteria air pollutant. It is a major component of smog.

Ozone Depletion: The reduction in the stratospheric ozone layer. Stratospheric ozone shields the Earth from ultraviolet radiation. The breakdown of certain chlorine and / or bromine-containing compounds that catalytically destroy ozone molecules in the stratosphere can cause a reduction in the ozone layer.

Ozone-Forming Potential: (See Reactivity.)

Ozone Layer: A layer of ozone in the lower portion of the stratosphere -- 12 to 15 miles above the Earth's surface -- which helps to filter out harmful ultraviolet rays from the sun. It may be contrasted with the ozone component of photochemical smog near the Earth's surface which is harmful.

Ozone Precursors: Chemicals such as volatile organic compounds and oxides of nitrogen, occurring either naturally or as a result of human activities, which contribute to the formation of ozone, a major component of smog.

Particulate Matter (PM): Any material, except pure water, that exists in the solid or liquid state in the atmosphere. The size of particulate matter can vary from coarse, wind-blown dust particles to fine particle combustion products.

Passive Solar: A system in which solar energy alone is used for the transfer of thermal energy. Pumps, blowers, or other heat transfer devices that use energy other than solar are not used.

Permit: Written authorization from a government agency that allows for the construction and / or operation of an emissions generating facility or its equipment within certain specified limits.

Persistence: Refers to the length of time a compound stays in the atmosphere, once introduced. A compound may persist for less than a second or indefinitely.

Photovoltaic (PV) Module: An integrated assembly of interconnected photovoltaic cells designed to deliver a selected level of working voltage and current at its output terminals, packaged for protection against environment degradation, and suited for incorporation in photovoltaic power systems.

Pilot scale: Size of a system between the small laboratory scale (bench-scale) and full-size system.

Plant Pathology: The scientific study of plant diseases caused by pathogens (infectious diseases) and environmental conditons (physiological factors).

Plume: A visible or measurable discharge of a contaminant from a given point of origin that can be measured according to the Ringelmann scale. (See Ringelmann Chart.)

Plunger Lift System: Use gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

$PM_{2.5}$: Includes tiny particles with an aerodynamic diameter less than or equal to a nominal 2.5 microns. This fraction of particulate matter penetrates most deeply into the lungs.

PM_{10} (Particulate Matter): A criteria air pollutant consisting of small particles with an aerodynamic diameter less than or equal to a nominal 10 microns (about 1/7th the diameter of a single human hair). Their small size allows them to make their way to the air sacs deep within the lungs where they may be deposited and result in adverse health effects. PM_{10} also causes visibility reduction.

Pneumatic controls: Control systems using either compressed gas or air.

Point Sources: Specific points of origin where pollutants are emitted into the atmosphere such as factory smokestacks. (See also Area-Wide Sources and Fugitive Emissions.)

Polycyclic Aromatic Hydrocarbons (PAHs): Organic compounds which include only carbon and hydrogen with a fused ring structure containing at least two benzene (six-sided) rings. PAHs may also contain additional fused rings that are not six-sided. The combustion of organic substances is a common source of atmospheric PAHs.

Polymer: Natural or synthetic chemical compounds composed of up to millions of repeated linked units, each of a relatively light and simple molecule.

Pounds per million BTU (lb/mmBtu): A measure of the mass (of a pollutant) emitted for each million British thermal units (Btu) of energy fed to a combustion source. A BTU is defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Precipitator: Pollution control device that collects particles from an air stream. (See Electrostatic Precipitator.)

Prescribed Burning: The planned application of fire to vegetation to achieve any specific objective on lands selected in advance of that application.

Prevention of Significant Deterioration (PSD): A permitting program for new and modified stationary sources of air pollution located in an area that attains or is unclassified for national ambient air quality standards (NAAQS). The PSD program is designed to ensure that air quality does not degrade beyond those air quality standards or beyond specified incremental amounts. The PSD permitting process requires new and modified facilities above a specified size threshold to be carefully reviewed prior to construction for air quality impacts. PSD also requires those facilities to apply BACT to minimize emissions of air pollutants. A public notification process is conducted prior to issuance of final PSD permits.

Primary Particles: Particles that are directly emitted from combustion and fugitive dust sources. (Compare with Secondary Particle.)

Produced water: Water extracted from the subsurface with oil and gas. It may include water from the reservoir, water that has been injected into the formation, and any chemicals added during the production/treatment process.

Production Tax Credit (PTC): an inflation - adjusted 1.5 cents per kilowatthour payment for electricity produced using qualifying renewable energy sources.

Programmic logic controller (PLC): Control software for engine mapping / reactant injection requirements used to control the SCR system.

Public Utility Regulatory Policies Act of 1978 (PURPA): One part of the National Energy Act, PURPA contains measures designed to encourage the conservation of energy, more efficient use of resources, and equitable rates. Principal among these were suggested retail rate reforms and new incentives for production of electricity by cogenerators and users of renewable resources.

Pulverized coal: is a coal that has been crushed to a fine dust in a grinding mill. It is blown into the combustion zone of a furnace and burns very rapidly.

Radionuclides: Atoms with an unstable nucleus, characterized by excess energy which is available to be imparted either to a newly-created radiation particle within the nucleus, or else to an atomic electron.

Reactive Organic Gas (ROG): A photochemically reactive chemical gas, composed of non-methane hydrocarbons, that may contribute to the formation of smog. Also sometimes referred to as Non-Methane Organic Gases (NMOGs). (See also Volatile Organic Compounds and Hydrocarbons.)

Reactivity (or Hydrocarbon Photochemical Reactivity): A term used in the context of air quality management to describe a hydrocarbon's ability to react (participate in photochemical reactions) to form ozone in the atmosphere. Different hydrocarbons react at different rates. The more reactive a hydrocarbon, the greater potential it has to form ozone.

Reasonably Available Control Measures (RACM): A broadly defined term referring to technologies and other measures that can be used to control pollution. They include Reasonably Available Control Technology and other measures. In the case of PM_{10}, RACM refers to approaches for controlling small or dispersed source categories such as road dust, woodstoves, and open burning.

Reasonably Available Control Technology (RACT): Control techniques defined in U.S. EPA guidelines for limiting emissions from existing sources in nonattainment areas. RACTs are adopted and implemented by states.

Reciprocating Internal Combustion Engine (RICE): An engine in which air and fuel are introduced into cylinders, compressed by pistons and ignited by a spark plug or by compression. Combustion in the cylinders pushes the pistons sequentially, transferring energy to the crankshaft, causing it to rotate.

Refraction: The change in direction of a light wave due to a change in its speed when it passes from one medium to another.

Regional Haze: The haze produced by a multitude of sources and activities which emit fine particles and their precursors across a broad geographic area. National regulations require states to develop plans to reduce the regional haze that impairs visibility in national parks and wilderness areas.

Regional Haze Rule: The Regional Haze Rule calls for state and federal agencies to work together to improve visibility in 156 national parks and wilderness areas such as the Grand Canyon, Yosemite, the Great Smokies and Shenandoah.
The rule requires the states, in coordination with the Environmental Protection Agency, the National Park Service, U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties, to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment. The first State plans for regional haze are due in the 2003-2008 timeframe. Five multi-state regional planning organizations are working together now to develop the technical basis for these plans.

Regulatory Impact Analysis (RIA): A tool used to assess the likely effects of a proposed new regulation or regulatory change.

Reid Vapor Pressure: Refers to the vapor pressure of the fuel expressed in the nearest hundredth of a pound per square inch (psi) with a higher number reflecting more gasoline evaporation.

Renewable Energy: Renewable Energy is energy derived from resources that are regenerative or, for all practical purposes, cannot be depleted.

Renewable Energy Resources: Energy resources that are naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Renewable energy resources include: biomass, hydro, geothermal, solar, wind, ocean thermal, wave action, and tidal action.

Renewable Portfolio Standard (RPS): a mandate requiring that renewable energy provide a certain percentage of total energy generation or consumption.

Retrofit or retrofitting: The addition of new technology or features to older systems.

Rich Burn Engine: Any four-stroke spark ignited engine with a manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NOx (such as pre-combustion chambers) will be considered lean burn engines. Existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Ringelmann Chart: A series of charts, numbered 0 to 5, that simulate various smoke densities by presenting different percentages of black. A Ringelmann No. 1 is equivalent to 20 percent black; a Ringelmann No. 5 is 100 percent black. They are used for measuring the opacity or equivalent obscuration of smoke arising from stacks and other sources by matching the actual effluent with the various numbers, or densities, indicated by the charts.

Risk Assessment: An evaluation of risk which estimates the relationship between exposure to a harmful substance and the likelihood that harm will result from that exposure.

Risk Management: An evaluation of the need for and feasibility of reducing risk. It includes consideration of magnitude of risk, available control technologies, and economic feasibility.

Risk Management Plan (RMP): A document prepared by a project manager to foresee risks, estimate effectiveness, and to create response plans to mitigate them.

Sanctions: Actions taken against a state or local government by the federal government for failure to plan or to implement a State Implementation Plan (SIP). Examples include withholding of highway funds and a ban on construction of new sources of potential pollution.

Scrubber: An air pollution control device that uses a high energy liquid spray to remove aerosol and gaseous pollutants from an air stream. The gases are removed either by absorption or chemical reaction.

Secondary Particle: Particles that are formed in the atmosphere. Secondary particles are products of the chemical reactions between gases, such as nitrates, sulfur oxides, ammonia, and organic products.

Selective Catalytic Reduction (SCR) or selective non-catalytic reduction (SNCR): Selective catalytic reduction means a noncombustion control technology that destroys NOx by injecting a reducing agent (e.g., ammonia) into the flue gas that, in the presence of a catalyst (e.g., vanadium, titanium, or zeolite), converts NOx into molecular nitrogen and water.

Selexol: Selexol is the trade name for a physical solvent that is a mixture dimethyl ethers of polyethylene glycol. In the Selexol process, the solvent dissolves the CO_2 from the gas stream at a relatively high pressure, generally in the range of 300 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2.

Sensitive Groups: Identifiable subsets of the general population that are at greater risk than the general population to the toxic effects of a specific air pollutant (e.g., infants, asthmatics, elderly).

Sequestration: Capture and long term storage of carbon. See also Carbon Capture and Storage

Smog: A combination of smoke and other particulates, ozone, hydrocarbons, nitrogen oxides, and other chemically reactive compounds which, under certain conditions of weather and sunlight, may result in a murky brown haze that causes adverse health effects.

Smoke: A form of air pollution consisting primarily of particulate matter (i.e., particles released by combustion). Other components of smoke include gaseous air pollutants such as hydrocarbons, oxides of nitrogen, and carbon monoxide. Sources of smoke may include fossil fuel combustion, prescribed and agricultural burning, and other combustion processes.

Solar Energy: The radiant energy of the sun, which can be converted into other forms of energy, such as heat or electricity.

Solar Thermal Collector: A device designed to receive solar radiation and convert it into thermal energy. Normally, a solar thermal collector includes a frame, glazing, and an absorber, together with the appropriate insulation. The heat collected by the solar thermal collector may be used immediately or stored for later use. Solar Thermal Collector, Special: An evacuated tube collector or a concentrating (focusing) collector. Special collectors operate in the temperature (low concentration for pool heating) to several hundred degrees Fahrenheit (high concentration for air conditioning and specialized industrial processes).

Soot: Very fine carbon particles that have a black appearance when emitted into the air.

Source: Any place or object from which air pollutants are released. Sources that are fixed in space are stationary sources and sources that move are mobile sources.

Spark ignition (SI): Ignition of combustion within an engine using spark plugs with a high-intensity spark of timed duration to ignite a compressed fuel-air mixture within the cylinder. SI engines are available in sizes up to 5 MW. Natural gas is the preferred fuel in electric generation and CHP applications of SI.

Stack Gas Bypass: The practice of routing some portion of exhaust gas, often from a large boiler, around the pollution control equipment, and into the exhaust stack. This is usually done to introduce hot, unscrubbed, gas into the stack to mix with and raise the temperature of the cool, scrubbed gas above its acid dew point and/or to increase plume buoyancy and dispersion. If the gas cools to its acid dew point, acid mists and droplets may fall out near the stack, or corrode unprotected stack linings.

State Implementation Plan (SIP): The group of plans and regulations submitted by a state to the U.S. EPA for implementation of the federal Clean Air Act.

Stationary Sources: Non-mobile sources such as power plants, refineries, and manufacturing facilities which emit air pollutants. (See also mobile sources).

Still vent column: Emission point for regeneration of glycol streams, resulting in vapors of water, VOC and HAPs.

Stoichiometric engine: An engine with the chemically correct proportion of fuel to air in the combustion chamber during combustion.

Storage Tank: Any stationary container, reservoir, or tank, used for storage of liquids.

Stratosphere: The layer of the Earth's atmosphere above the troposphere and below the mesosphere. It extends between 10 and 30 miles above the Earth's surface and contains the ozone layer in its lower portion. The stratospheric layer mixes relatively slowly; pollutants that enter it may remain for long periods of time.

Subsidy: Financial assistance granted by the Government to firms and individuals.

Sulfur Dioxide (SO_2): A strong smelling, colorless gas that is formed by the combustion of fossil fuels. Power plants, which may use coal or oil high in sulfur content, can be major sources of SO_2. SO_2 and other sulfur oxides contribute to the problem of acid deposition. SO_2 is a criteria air pollutant.

Sulfur Oxides (SOx): Pungent, colorless gases (sulfates are solids) formed primarily by the combustion of sulfur-containing fossil fuels, especially coal and oil. Considered major air pollutants, sulfur oxides may impact human health and damage vegetation.

Syngas: Syngas is the gas product resulting from gasification processes and can be used as a fuel to drive power generation or a feedstock for chemical synthesis.

Tailpipe emissions: Products of burning fuel in the vehicle's engine emitted from the vehicle's exhaust system.

Thief hatch: Opening in the top of the stock tank that allows tank access to the interior of the tank for withdrawal or measurement of fluid.

Title V: A section of the 1990 amendments to the federal Clean Air Act that requires a federally enforceable operating permit for major sources of air pollution.

Topography: The configuration of a surface, especially the Earth's surface, including its relief and the position of its natural and man-made features.

Total dissolved solids (TDS): The combined content of all inorganic and organic substances contained in a liquid which are present in a molecular, ionized or micro-granular (colloidal sol) suspended form.

Total Suspended Particulate (TSP): Particles of solid or liquid matter -- such as soot, dust, aerosols, fumes, and mist -- up to approximately 30 microns in size.

Toxic Hot Spot: A location where emissions from specific sources may expose individuals and population groups to elevated risks of adverse health effects -- including but not limited to cancer -- and contribute to the cumulative health risks of emissions from other sources in the area.

Trading Credits: The basic concept of a cap and trade system is that the government turns a certain quantity of emissions into a marketable commodity, called a credit, which is then allowed to be bought and sold freely on the market. See http://www.epa.gov/airmarkets/trading/basics.html

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

Triethylene glycol (TEG) dehydrator: Any device in which a liquid glycol (including, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

Troposphere: The layer of the Earth's atmosphere nearest to the surface of the Earth. The troposphere extends outward about five miles at the poles and about 10 miles at the equator.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Underground Storage Tank (UST): Refers to tanks used to store gasoline underground.

United States Environmental Protection Agency (U.S. EPA): The federal agency charged with setting policy and guidelines, and carrying out legal mandates for the protection of national interests in environmental resources.

Urea: An organic compound of carbon, nitrogen, oxygen and hydrogen, with the formula CON_2H_4 or (NH_2) CO_2 or CN_2H_4O. Used as a catalyst for SCR applications.

Vanadium: A chemical element in the periodic table that has the symbol V and atomic number 23. A rare, soft and ductile element, vanadium is found combined in certain minerals and is used mainly to produce certain alloys.

Vapor recovery unit (VRU): A system composed of a scrubber, a compressor and a switch. Its main purpose is to recover vapors formed inside completely sealed crude oil or condensate tanks.

Vehicle Miles Traveled (VMT): The miles traveled by motor vehicles over a specified length of time (e.g., daily, monthly or yearly) or over a specified road or transportation corridor.

Visibility: A measurement of the ability to see and identify objects at different distances. Visibility reduction from air pollution is often due to the presence of sulfur and nitrogen oxides, as well as particulate matter.

Visibility Reducing Particles (VRP): Any particles in the atmosphere that obstruct the range of visibility.

Volatile: Any substance that evaporates readily.

Volatile Organic Compounds (VOCs): Carbon-containing compounds that evaporate into the air (with a few exceptions). VOCs contribute to the formation of smog and / or may themselves be toxic. VOCs often have an odor, and some examples include gasoline, alcohol, and the solvents used in paints.

Watt (Electric): The electrical unit of power. The rate of energy transfer equivalent to 1 ampere of electric current flowing under a pressure of 1 volt at unity power factor.

Watthour (Wh): The electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Weight of Evidence: The extent to which the available information supports the hypothesis that a substance causes an effect in humans. For example, factors which determine the weight-of-evidence that a chemical poses a hazard to humans include the number of tissue sites affected by the agent; the number of animal species, strains, sexes, relationship, statistical significance in the occurrence of the adverse effect in treated subjects compared to untreated controls; and the timing of the occurrence of adverse effect.

Welfare-Based Standard (Secondary Standard): An air quality standard that prevents, reduces, or minimizes injury to agricultural crops and livestock, damage to and the deterioration of property, and hazards to air and ground transportation.

Wet Flue Gas Desulfurization (FGD): In wet scrubbers, the flue gas enters a large vessel (spray tower or absorber), where it is sprayed with water slurry (approximately ten percent lime or limestone). The calcium in the slurry reacts with the SO2 to form calcium sulfite or calcium sulfate. A portion of the slurry from the reaction tank is pumped into the thickener, where the solids settle before going to a filter for final dewatering to about 50 percent solids. The calcium sulfite waste product is usually mixed with fly ash (approximately 1:1) and fixative lime (approximately five percent) and disposed of in landfills. Alternatively, gypsum can be produced from FGD waste, which is a useful by-product.

Wind Energy: Energy present in wind motion that can be converted to mechanical energy for driving pumps, mills, and electric power generators. Wind pushes against sails, vanes, or blades radiating from a central rotating shaft.

Woodburning Pollution: Air pollution caused by woodburning stoves and fireplaces that emit particulate matter, carbon monoxide and odorous and toxic substances.

Zeolite: Minerals that have a micro-porous structure.

Zero Emissions Dehydrator: A Zero Emissions Dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent. Rather than being released as vapor, the water and hydrocarbons are collected from the glycol still column, and the condensable and non-condensable components are separated from each other. The two primary condensable products are wastewater, which can be disposed of with treatment; and hydrocarbon condensate, which can be sold. The non-condensable products (methane and ethane) are used as fuel for the glycol reboiler instead of venting to the atmosphere.

Table of Mitigation Options Not Written with Rationale

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SECTION	MITIGATION OPTION TITLE	RATIONALE FOR NOT WRITING
Oil and Gas: Stationary RICE (Small and large engines)	Emission limit on existing engines (1g/hp hr and 2g/hp hr)	Will incorporate this into the NSPS mitigation option and note that it will apply to existing engines.
	Replacing ignition systems to decrease false starts	This option is generally covered in the Operation and Maintenance mitigation option
	Replace piston rod packing (pumps)	This will be added to the Operation and Maintenance mitigation option.
	Minimize (control?) engine blow downs	This is already a common industry practice and has been deleted as an option
	Utilize exhaust gas analyzers to adjust AFR	This was included in the Oxidation Catalysts and AFRC on Lean Burn Engines option.
	Smart AFRC (air-fuel-ratio-controller)	Included in the other AFRC options
	Replace gas engine starters with electric air compressors	Negligible emissions reductions for applying this option.
	Provide training for field personnel on engine maintenance with regard to AQ considerations	Incorporated into Option titled “Adherence to Manufacturers’ Operation and Maintenance Requirements”
Oil and Gas: Mobile and Non-Road		
Oil and Gas: Rig Engines	Analysis of all drill rigs – replace the dirtiest 20%	Will reference in Tier 2-4 Mitigation Option Development, but also move to overarching discussion to determine the priority on rig engine reductions
	Electric Powered Drill Rig	Not selected due to low feasibility around availability of electricity
Oil and Gas: Turbines		
Oil and Gas: Exploration & Production (Tanks)	Mufflers	Does not apply to Air Quality.
	Centralized Collection for Existing Sources	This option is not feasible for retrofit application in the San Juan Basin

SECTION	MITIGATION OPTION TITLE	RATIONALE FOR NOT WRITING
Oil and Gas: Exploration & Production (Dehydrators/Separators/ Heaters)	Centralized Dehydrators	Already or will be incorporated in other papers on centralization
	Optimization and automation	Incorporated into the Option under Stationary RICE subsection.
	Low/Ultra low NOx burners	Application not appropriate for the San Juan Basin, because most burners commonly used in the Four Corners Area smaller than the technology is capable of providing emission reduction.
	Install VRU	Principle of the option as applied is explained in the Option titled "Install VRU" under subsection for E&P Tanks.
	Centralized Dehydrators	Principle of the option is incorporated into the Option under Stationary RICE. Additionally, the San Juan Basin does not have a high need for wellhead dehydration.
Oil and Gas: E&P Pneumatics/ Controllers/ Fugitives	Directed inspection and maintenance program	Addressed by Option title "Specific Direction for How to Meet NSPS and MACT Standards: Directed Inspection and Maintenance" in Midstream section.
Oil and Gas: Midstream Operations	Install Flares	Never submitted.
Oil and Gas: Overarching Issues		
Power Plants: Future	Integrated Gasification Combined Cycle (IGCC) Political Aspects and Incentives	Combined with Integrated Gasification Combined Cycle (IGCC) Technical Aspects and listed as mitigation option "Integrated Gasification Combined Cycle (IGCC)"
Power Plants: Overarching	Four Corners Area Mercury Studies	Combined with Participate and Support Mercury Deposition Studies
Other Sources:	Apply Uniform Regulations Between Jurisdictions for Dust Control	Never submitted.
	Fugitive Dust Road Mitigation Plan	See option papers on oil & gas road dust mitigation.
	Include Multi-Modal Transportation Options in 2035 Transportation Plan	Scope of this option is very large. A proposal was submitted to DOE.
	Pursue Clean Cities Designation for Western Slope	This was not awarded by DOE. Not clear just who would house and how funding could be sustainable.
	Auto Licensing or Registration Additional Tax	Group determined this was unlikely to be economically feasible at this time.
	Oil and Gas Fleet Retrofit / Replacement	Numerous options were written as part of the oil & gas section dealing with vehicles.

SECTION	MITIGATION OPTION TITLE	RATIONALE FOR NOT WRITING
Other Sources:	Consider Ambient Air Quality Before Burning Prescribed Fire	Never submitted.
	Develop Controls on Agricultural Burning in Colorado	Never submitted.
Energy Efficiency, Renewable Energy, Conservation	Corporate Rebate/incentives for Energy Efficiency	Combined with Building Standards for Increased Commercial and Residential Energy Efficiency (EE)
	Pilot Neighborhood project to Change Behavior to Reduce Energy Use – Increase Efficiency	Combined with Audits of Low Income Areas to find Simple Solutions
	Solar/PV Applications	Never submitted.
	Optimization of Compression	Incorporated into the Option under Stationary RICE subsection titled "Optimization and automation and Centralized Collection for New Sources"
	Micro Turbines	Incorporated into Option titled "Cogeneration/Combined Heat and Power"
	Product Capture/Maximize Efficiency	Never submitted.
	Multi-Phase Pipeline	Never submitted.
	Comprehensive Impacts of efficiency	Never submitted.
	Efficiency/Conservation on individual level	Never submitted.
	Sustainable business practices	Never submitted.
	Zero Waste	Never submitted.

GENERAL: PUBLIC COMMENTS

General Public Comments

Comment
Air quality in the Four Corners Area has been studied and cussed and discussed for several decades while the pollution problems grow and grow. We sincerely hope that measurable benefits to our environment will be the product of this massive piece of work by the Four Corners Air Quality Task Force. Polluting industries and enforcement agencies cannot continue to "turn their backs" on what IS happening to the quality of our air. It is our right to breathe clean air. We all know that San Juan County has serious air quality issues. San Juan County is ranked in the top 10% of worst counties in the United States for toxic releases to the environment according to Scorecard, a pollution information web site. These toxic releases include volatile organic compound emissions from oil and gas facilities, and power plant emissions such as particulate matter (PM) and sulfur dioxide. Many other toxic emissions are listed. All of these pollutants are threats to human health, the land and water. Enough is Enough! Now is the time to take action to clean up our environment! Regulatory agencies need to begin much stronger enforcement of current regulations and work toward more stringent regulations. Further degradation of our environment is not acceptable. State cancer profiles show that this area has the highest rate of cancer in New Mexico. Respiratory disease is high in the Four Corners Area. A comprehensive health study for the entire Four Corners Area would most likely reveal even more alarming health problems among our population. Clean up of area coal fired power plants and mandatory emissions controls and clean up of oil and gas facilities are necessary for the health and well being of the people. Health is wealth.
I've not read all the details of the report but I think there seems to be something missing. I don't see any analysis of the future demand on this area in terms of energy. There is a fast growing school of thought that indicates coal can provide the energy bridge the United States needs to exit the Middle East. I think people need to understand that the coal resources here in the San Juan Basin could become a big part of a new energy strategy for transportation. Electric cars and electric high speed trains could be used to help replace the demand for middle east oil being used now for gasoline and jet fuel. If this happens and I think it is coming in the next 10 years, what will we see here? Is any planning being done for that? If you think there is a lot of CO_2 from 3 power plants, what if there were 20? This may seem like bad news but it's not if we have a plan. For less than the cost of the Iraq war, we could install the infrastructure to convert the coal here into H_2 and CO_2. The H_2 could be used in new power plants driving engines turning generators thereby reducing the requirement for steam from water and the CO_2 could be captured and piped to Bakersfield to be injected into the heavy oils there in enhance oil recovery. The power grid will would require significant upgrades to accommodate the additional load in addition to providing ways for wind and solar power to come on the system. Instead of planning for war, let's plan for peace. This is a big effort. We need a leader with some vision at the Federal level. Is there someone who could have understood the impact of the internet and pushed to develop that infrastructure? Internet super highway -> I say Energy Super Highway!

Comment
The Southern Ute Indian Tribe Growth Fund (SUGF) appreciates the opportunity provided to the public to allow for review and comment on the Draft Four Corners Air Quality Task Force Report (Version 7); furthermore SUGF, is appreciative of the tremendous undertaking of the various resources that have come together to develop a range of possible air quality mitigation options that may remedy air quality issues in the Four Corners area. SUGF understands that this document is non-conclusive, and does not convey consensus of the various participating bodies regarding the mentioned mitigation options. It is further understood that these developed options may be considered by the various regulatory bodies to be implemented into air quality management strategies. At that time, it is recommended that public participation similar to this effort be duplicated. As you may be aware, production of natural gas is critical to the Southern Ute Indian Tribe's (Tribe) economic base and growth. The SUGF, a private investment entity of the Tribe supports development of its natural resources, yet remains cognizant of its responsibility to protect the environment. This is exemplified through Tribal processes such as conditional approval(s) of future oil and gas development that will require significant mitigation measures involving installation of control technologies on compression units. Another significant development occurring is the continual development of the Tribe's Air Quality Program, through the establishment of the Southern Ute Indian Tribe/State of Colorado Environmental Commission.
BP believes that the establishment of the Four Corners Task Force is a very useful venue for stakeholders and regulators to discuss air quality issues with the ultimate goal of managing air quality in the region. Developing strategies to measurably improve air quality requires extensive technical, engineering and policy analyses. In addition, such analyses require time and should not be influenced by arbitrary schedules. BP believes that solutions to the issues should be crafted on the basis of air quality improvement and economic efficiency. Control requirements based on a "one size solution" may not result in measurable air quality improvements nor be the most economic solution for improving air quality. BP also believes that it is important for the Task Force to focus on understanding source receptor relations in the region through modeling and analysis of existing air quality data as well as emission data.
I could not find the Federal Register notification for this superficial 'public comment' period. This process is fatally flawed as proper 'government to government meetings' have not been held. The formal notification has not been provided to all American Indian Nations and official respective American Indian Nation Tribal Council has not been officially made known. How will such federal mandates affect the sovereignty of American Indian Nations? This appears to violate basic principles of American Indian Nation Treaties as it does the Law of Nations. It appears, these federal agencies are recruiting non-profits to further international agendas for their federal acquisitions while attempting to impose hidden taxation. These federal regulatory actions certainly appear to emphasize regulation without representation as it promotes no accountability while encouraging implementation of un-ratified international conventions such as Kyoto. I attended the first meeting held in Farmington New Mexico for the Four Corners area regarding Air Quality on November 4, 2005. I spoke with a federal officer in her official capacity who acknowledged this process was indeed implementing the Kyoto Treaty that is un-ratified by U.S. Congress. She also acknowledged that the way the federal agencies were working around this un-ratified treaty was by entering into Memorandums of Understanding (MOU) between the respective State governments. These MOU's are signed by State governors as is the case with New Mexico State Governor Bill Richardson. New Mexico Governor Richardson proposed adoption of a regional climate change scheme to California Governor Arnold Schwarzenegger as stated in Executive order June 9, 2005. New Mexico Governor Richardson displays a definite conflict of interest as he continues to enjoy the pleasure of the United Nations while acting as United Nations Ambassador and more of an International Citizen, during his term as New Mexico Governor. A man cannot serve two masters anymore than he can be a citizen of two countries.

Comment
I received an email from a member of Montezuma Vision Project May 2, 2007 who wrote in reference to membership; "Most of the people are progressives who are interested in promoting planning for good quality of life." The main intent behind those who claim to be Progressives is to reduce "right" to privilege and "liberty" to servitude. Progressives enjoy collectivism implemented upon the masses while they enjoy their appointed and self anointed aristocracy oligarchy. The first U.S. Progressive Party formed in 1912 and has found its niche in liberalism and the environmental movement. There are Progressives connected to Democratic Socialist parties. Progressives believe and implement the old Roman Prodigal estate schemes promoted by IUCN (International Union for Conservation of Nature) which in reality is promoting Sustainable Development as specified in Agenda 21- 1992 Rio Summit Declaration. The Kyoto Protocol was created by an Intergovernmental Panel on Climate Change established in 1988 jointly by World Meteorological Organization and the United Nations Environment Programme. The Convention (Kyoto Protocol To The United Nations Framework Convention On Climate Change) was adopted by the Conference of the Parties meaning Parties to the Convention, May 1992, while in New York. The Montreal Protocol on Substances that Deplete the Ozone Layer was adopted by the Conference of the Parties September 1987. The federal officer while I was at November 4, 2005 meeting, acknowledged this entire process was truly implemented the Untied Nations, World Bank, IMF, Federal Reserve, and agenda for Sustainable Development which is also known as Agenda 21. The federal officer told me that there is a system in place for schemes that allow for a 'pay to pollute' program. She provided the example of power plants on the East Coast that do not have state of the art environmental equipment and cannot be fitted or converted with such state of the art environmental equipment. Certificates from power plants in Western U.S. who are newer and have up dated equipment as well as cleaner coal, would sell certificates to the Eastern U.S power plants as a means of offsetting Eastern power plant pollution. In reality, this is a pay to pollute scheme that mirrors the new-politically correct scheme of paying to have a 'Carbon Imprint or Footprint'. Example: a representative from Nature Conservancy conducts a Carbon Imprint intake of your life. The calculations are conducted on life style such as how often a person drives a car, fly's an airplanes, rides a bicycle, uses a microwave oven and so forth. Once the representative determines the Carbon Imprint number, the person is expected to pay an outrageous sum of money (Federal Reserve Notes) to an environmental non profit of his or her choice to off set the Carbon Imprint. In reality, this is extortion at its best while providing a steady source of income to environmental non profits who may not otherwise obtain such vast forms of income. It certainly appears this entire scheme is just another form of taxation forced upon the public. While I was in attendance at November 4, 2005 meeting I listened to the key-note speaker talk of new EPA standards that must be implemented. In reality, he was telling the public this unfunded and unjustified federal mandate 'must' be complied to. Meanwhile, he mentioned the Four Corners area has dust & silt particles blown in from other larger cities as far away as Phoenix and Tucson Arizona and beyond. There were a lot of charts on the walls and the mercury issue in the Four Corners was displayed as being mainly caused from the power plants that exist in the area. First of all, there is a natural occurrence of mercury in the San Juan Mountains. Second, plants are known to absorb mercury from the ground. If the plants and trees absorb this mercury from the ground and a wildfire of significant proportions occurs what is going to happen? The mercury will be released by residual ash and debris back into the ground and even into the water supply. This cycle was not demonstrated at this meeting nor is it ever discussed. This monitoring process and so called evidence collecting done in this entire process is fatally flawed while it certainly indicates fatal deficiencies in the precision in monitoring as it suggests other uncertainties.

Comment
The picture displayed upon the website depicting this proposed Four Corners Air Quality catastrophe is fatally flawed. Photographs can be easily manipulated to reflect whatever the crisis especially with today's technology. The pictures did not show what type of a day it was such as was it a cold day or a hot day? Sometimes in this area of the Four Corners depending upon what time of the morning and what moisture is in the air, visibility can be poor from the natural moisture in the air as well as wind passing through can cause dust from the ground to be in the air. The EPA expecting to regulate such natural processes in nature is absurd. The natural occurrences were not discussed at this meeting anymore than it was reflected in any of the charts or photographs. I see this entire process as in terminal as it is fatally in error. Most of all, I see federal agencies and cohorts attempting to play God while trying to control nature. This is preposterous to claim the environment that includes animals, plants and all of nature is above humans. This is perversions of natural law at its best especially when EPA claims it can control wind, dust and weather while expecting an area such as the Four Corners to keep that dust from blowing in from other areas. It is just as absurd to create this hyped up crisis just to sell certificates to pollute and extort money from the public. Cease and desist all these actions of implementing un-ratified illegal international treaties through abusing MOU's and other such agreements. Stop trying to play God while creating a crisis just to extort money from the public and expand progressivism.

The Association between Ambient Air Quality Ozone Levels and Medical Visits for Asthma in San Juan County

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Abstract

The New Mexico Department of Health (NMDOH) Environmental Health Tracking Project has been compiling and analyzing data on air quality and respiratory health of New Mexicans. While other studies in the United States have shown an association between the frequency of asthma attacks and ground level ozone in large urban areas, few researchers have focused on largely rural communities in the desert southwest. To perform the analysis, the daily number of asthma-related emergency room visits to emergency departments for 2000 to 2003 were matched to daily ozone levels during April – September. The ozone concentration data were obtained from nationwide datasets compiled by the Environmental Protection Agency, but were collected by the NM Environment Department Air Quality Bureau. The study focused on ground level ozone during April to September because ground level ozone accumulates when warmer and longer days cause nitrogen oxides and volatile organic compounds in the air to react and generate ozone. These reactions can cause ozone concentrations to increase by more than 20 parts per billion (ppb) from one day to the next.

The analysis used a statistical model to predict the effect that these changes in ozone concentrations have on the number of asthma-related emergency room visits. Two health outcomes were considered: daily presence or absence of an asthma-related medical visit and the number of visits. Ozone was associated with asthma-related medical visits. The distribution of ozone concentrations was similar to that observed in many large cities. Increased ozone (lagged two days) was associated with increased odds of at least one asthma-related medical visit by 42 %. The study found that when ozone increased by 20 ppb the number of emergency room visits increased by about 34%. While this is a small increase in the number of visits, sensitive persons may want to monitor air quality index forecasts to help limit their exposure to ozone. Ozone concentrations typically are highest in the early afternoon, so sensitive individuals should try to reduce their outdoor activities during this part of the day.

Background

Exposure to air pollutants, such as ozone, nitrogen dioxide, sulfur dioxide and particulates, have repeatedly been shown to be associated with negative health outcomes, including mortality, reduced lung function growth and asthma (Dominici et al. 2003, Gauderman et al. 2000, Tolbert et al. 2000). However, most of these studies have been conducted in large urban areas, with many of these in the eastern United States or the western coast. The distribution of these air pollutants and the sources of these pollutants may differ considerably from rural areas or areas in the high desert Southwest.

In an Environmental Protection Agency (EPA) study of air quality in New Mexico, Sather showed that the ozone concentrations in San Juan County were increasing and were among the highest in EPA sites in the Southwest (Sather 2004). He further concluded that the levels were similar throughout most of the county and that NOx and alkanes were the main volatile organic compounds in the ozone development.

Health outcomes associated with air quality have not been studied in a rural, southwestern high desert environment. Thus, we conducted a study of asthma-related medical visits in San Juan County and present an alternative statistical approach that deals with some of the limitations of data obtained in a rural area.

Study Area

San Juan County, New Mexico is a rural county in the high desert of northwest New Mexico, with an elevation of 5145 feet and an average rainfall of 9.3 inches. The county covers over 5000 square miles, but had a population of 114,000 in 2000, resulting in a low density of 21 people per square mile. The main city is Farmington, with a population of 38,000. All other towns have a population under 10,000, with most being considerably smaller. Although the area is rural, the county residents are concerned about air pollution and the potential health risks, especially with respect to asthma. Major industries center on coal, oil and natural gas production. Air pollution sources include coal-based power plants and production of gas and oil. Two more large coal-fired power plants may be built within the county. With the increased number of forest fires in the West and the hundreds of miles that the smoke from these fires has traveled, forest fires also have had a considerable impact on the air quality.

Asthma Surveillance

Through a CDC cooperative agreement starting in 2000, the NMDOH developed a statewide asthma surveillance system. With renewed funding NMDOH has continued surveillance and has expanded its role to education, improving access to care and reducing the effects of environmental factors associated with asthma. In 2003, NMDOH received funding through the CDC Environmental Public Health Tracking Program to link environmental exposure data with health outcome data. As part of this program, NMDOH, in collaboration with the UNM, linked data on air quality and asthma in San Juan County. Both hospitalization discharge and urgent care visit information were obtained through the statewide asthma surveillance system for January 1, 2000 through December 31, 2003. Age, sex and zip code of residence were obtained for each visit.

Air Quality Data

New Mexico Environment Department (NMED) collected air quality data from three monitors within the county. The Bloomfield and San Juan Substation monitors ran continuously and collected hourly data on air quality and weather conditions. While both monitors were operating as of January 1, 2000, ozone was not collected at the Bloomfield station until June 7, 2000. The Bloomfield monitor is approximately 15 miles east of Farmington in the town of Bloomfield. The Substation is located at the Shiprock Electrical Substation, approximately 15 miles west of Farmington, near the Public Service Company of New Mexico San Juan Generating Station, and a few miles north of the Arizona Public Services Four Corners Power Generating Station.

Methods

Statistical Methods

Two health outcomes were considered: the number of asthma-related medical visits per day and a binary indicator as to whether or not any medical visits during a day were asthma-related. Since we were primarily interested in the association of ozone levels with asthma-related medical visits, we restricted the yearly study period to May 1 through September 15, when over 90% of the eight hour average ozone concentrations were above 50 ppb. Variables for which data were collected hourly were summarized as both the daily maximum hourly value and the maximum eight hour average value. While the maximum eight hour value for ozone is used in regulatory standards, we also wanted to consider if shorter term peaks, such as those indicated by high daily maximum hourly values, may be important to health outcomes. For measurements taken at two stations, the association between the two daily ozone values was assessed and the maximum of the two values was used.

Modeling

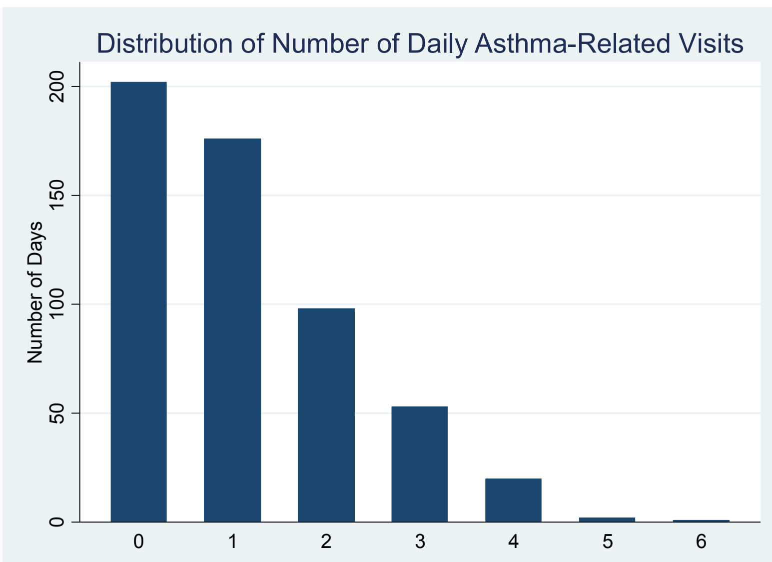
The daily number of asthma-related medical visits was modeled using Poisson regression. Primary exposure variables were the maximum daily values for the eight-hour average hourly ozone concentrations. Lags of zero to five days from exposure to visit day were examined to determine the amount of time between exposure and effect. Covariates were included to adjust for seasonal components, year, week day, holidays (lagged zero to two days) and school year. Variables were included only if the significance level was less than 0.10. Single pollutant models were obtained by adding an exposure variable to this best covariate model. Only the variables significant at $p<0.10$ in the single pollutant models were examined in the overall model, but these variables were retained only if the significance level was less than 0.05. Since the number of daily visits generally was small, logistic regression was used to model whether or not any asthma-related medical visit was observed on a day. The same procedure, including the same predictor variables and covariates, that was used in the Poisson regression modeling was used in the logistic regression modeling.

Since the number of daily asthma-related medical visits was small and the number of days with zero counts was larger than expected under the Poisson model, the Zero-Inflated Poisson (ZIP) model also was used (Dobbie and Welsch 2001; Hall and Zhang 2004). This model contains two components: the first predicts the probability of observing at least one asthma-related visit in a day (binary component) and the second estimates the number of visits (count component). The coefficients in the two components are estimated simultaneously. Only variables significant at < 0.10 at entry were retained. All statistical modeling was done in R.

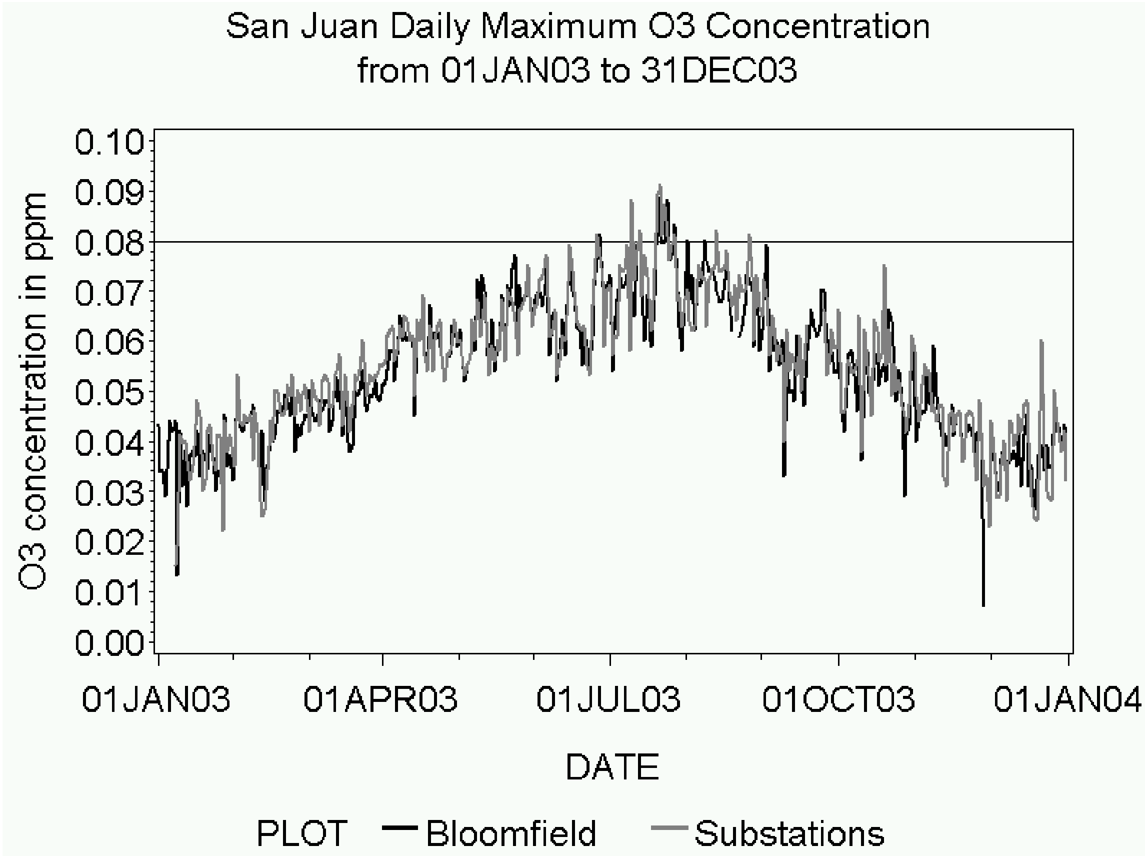
Results

Health Outcomes

During the summer months (May 1 through September 15) of 2000 through 2003, 627 asthma-related medical visits were reported in San Juan County. Asthma-related visits ranged from 0 to 6 per day, with a median of 1 and mode of 0 (Figure 2). At least one patient made an asthma-related visit on 350 (63.4%) of the 552 study days. Although age, gender and zip code information were available, the number of visits or proportion of days with an asthma-related visit were too low for successful modeling, so no assessment by these variables are included.



Air Quality: Ozone peaks during the summer months. Analyses were restricted to the summer months, from May 1 through September 15. Ozone concentrations at the two monitors were very similar. For air quality parameters that were measured at two monitors, the maximum value was used. The median daily eight hour maximum ozone level was 63 ppb during the summer months, with a maximum value of 85. All air quality variables exhibited distributions skewed to high values, but ozone was the least skewed. The maximum value for ozone was only 35% of the median.



Regression Models: To model the odds of at least one asthma-related medical visit, logistic regression models with adjustment for the seasonal components, weekday, holiday and spring school time were developed. The best lags were two days for ozone. Ozone was associated with increased odds of at least one asthma-related medical visit (OR=1.42; 95% CI: 1.09, 1.95; $p < 0.01$). To model the count of the number of asthma-related medical visits, Poisson regression models were also used with adjustment for the seasonal components, weekday, holiday and year. Ozone was associated with an increased count of visits, with a relative risk of 1.11 per 10 ppb ozone (95% CI: 0.98, 1.24). Zip models were used to simultaneously model the probability of any asthma-related medical visits and the number of visits per day. Adjustment factors were determined for the separate binary and count components, with no adjustment in the binary component and adjustment for the seasonal components, weekday, holiday and year in the count component. While ozone was significant in the binary component ($p<0.05$), the overall association was not significant ($p=0.09$).

Discussion

We have shown that ambient ozone concentrations are associated with asthma-related medical visits in a rural area of the high desert in San Juan County, New Mexico. While there is an indication that the number of visits rise along with increases in ozone, the most important result is that the odds of asthma-related visits increase with increasing ozone (1.42; 95% CI: 1.09, 1.85).

The basic association of increased asthma consequences with increased ozone has been shown in many urban areas. The distribution of ozone values in San Juan County is similar to those observed in other studies, but the extreme values are not necessarily as high in San Juan County. For example, while the highest single hour and eight-hour averages were 96 ppb and 83 ppb in San Juan County, respectively, studies in Atlanta had maximum one hour concentrations of 132 ppb, (Stieb et al. 1996; Tolbert et al. 2000). However, studies in Seattle (8-hour maximum=83.1 ppb) and Santa Clara County, CA (1-hour maximum=70 ppb) had similar, but slightly lower maximum concentrations (Lipsett et al. 1997; Norris et al. 1999).

The high values in San Juan County are of concern. The federal regulatory standard is 84 ppb for the three-year average of the annual fourth highest eight hour average. During the study period, the county reached a three-year average of 78 ppb. Furthermore, in an EPA study of air quality in New Mexico, Sather concluded that the ozone concentrations in San Juan County during 2000-2003 were higher than the previous three years and were among the highest among EPA regional sites in the Southwest including Arizona, Utah, Colorado, New Mexico and Texas (Sather 2004). Sather also showed that ozone was high in many parts of the county, including the middle of the county near the population center and the sparsely populated western and northeastern parts of the county. The largest hourly change in ozone concentrations was only 18 ppb, indicating that nitrogen oxides and alkanes were the main compounds in the ozone development. Similar to studies of urban areas, the most effective lag is two days between the occurrence of the ozone concentration and the asthma-related visits (Hwang et al. 2004; Stieb et al. 1996).

Studies to address health issues in rural areas are more often hampered by small counts than similar studies in urban areas. Use of standard methods such as Poisson regression may not be appropriate, and the modification of the data to look at binary outcomes may lose vital information. Thus, a model such as the ZIP model may be appropriate in many rural health studies, as in other studies with small counts.

This study includes several limitations. As discussed above, studies in rural areas are often limited by small sample sizes. However, our modeling approach effectively dealt with small, including zero, counts. While the county covers a large area, there were only two monitors for each air quality parameter. Furthermore, address information was limited to zip code, so there was no effective method to obtain better exposure information than that obtained from one monitor or the average of two monitors. However, we did limit the study sample to people residing in the county. Prior studies of the spatial trends in ozone indicated some but not significant differences in ozone across the county.

Conclusions

Although a rural area, San Juan County, New Mexico experiences high ozone concentrations, as high as some urban areas and high for the Southwest. The analysis used a statistical model to predict the effect that these changes in ozone concentrations have on the number of asthma-related emergency room visits. Two health outcomes were considered: daily presence or absence of an asthma-related medical visit and the number of visits. Ozone was associated with asthma-related medical visits. The distribution of ozone concentrations was similar to that observed in many large cities. Increased ozone (lagged two days) was associated with increased odds of at least one asthma-related medical visit by 42 %. The study found that when ozone increased by 20 ppb the number of emergency room visits increased by about 34%. While this is a small increase in the number of visits, sensitive persons may want to monitor air quality index forecasts to help limit their exposure to ozone. Ozone concentrations typically are highest in the early afternoon, so sensitive individuals should try to reduce their outdoor activities during this part of the day.

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Regional Impacts of Oil and Gas Development on Ozone Formation in the Western United States

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ABSTRACT

The Intermountain West is currently experiencing increased growth in oil and gas production, which has the potential to affect the visibility and air quality of various Class I areas in the region. The following work presents an analysis of these impacts using the Comprehensive Air Quality Model with extensions (CAMx). CAMx is a state-of-the-science, "one-atmosphere" Eulerian photochemical dispersion model that has been widely used in the assessment of gaseous and particulate air pollution (ozone, fine [$PM_{2.5}$], and coarse [PM_{10}] particulate matter). Meteorology and emissions inventories developed by the Western Regional Air Partnership Regional Modeling Center for regional haze analysis and planning are used to establish an ozone baseline simulation for the year 2002. The predicted range of values for ozone in the national parks and other Class I areas in the western United States is then evaluated with available observations from the Clean Air Status and Trends Network (CASTNET). This evaluation demonstrates the model's suitability for subsequent planning, sensitivity, and emissions control strategy modeling. Once the ozone baseline simulation has been established, an analysis of the model results is performed to investigate the regional impacts of oil and gas development on the ozone concentrations that affect the air quality of Class I areas. Results indicate that the maximum 8-hr ozone enhancement from oil and gas (9.6 parts per billion [ppb]) could affect southwestern Colorado and northwestern New Mexico. Class I areas in this region that are likely to be impacted by increased ozone include Mesa Verde National Park and Weminuche Wilderness Area in Colorado and San Pedro Parks Wilderness Area, Bandelier Wilderness Area, Pecos Wilderness Area, and Wheeler Peak Wilderness Area in New Mexico.

IMPLICATIONS

Population growth in the western United States is driving a rapid increase in the generation of electricity and fossil fuel production, leading to higher NO_x emissions and the potential to affect the visibility and air quality of Class I areas in the region. Although total emissions from oil and gas development are small compared with other categories such as coal-fired power plants and automobiles, they occur in remote locations and can have a disproportionate effect on the air quality of national parks and wilderness areas. The following work provides an analysis of these impacts on ozone concentrations using a state-of-the-science photochemical dispersion model.

INTRODUCTION

High ozone (O_3) levels at the Earth's surface, such as the photochemical smog that frequently envelopes Los Angeles in the summer, have typically been regarded as an urban air quality problem. However, a disturbing trend in recent years has been the rise of tropospheric O_3 in remote regions of the western United States,[1] many of which are Class I areas (international parks, national wilderness areas that exceed 5000 acres in size, national memorial parks that exceed 5000 acres in size, and national parks that exceed 6000 acres in size) as designated by the Clean Air Act. Possible explanations for this trend include increasing background concentrations, largely due to emissions from Asia[2–4] or changes in the magnitude or distribution of regional emissions.[1]

O_3 is a strong oxidant that can reduce lung function and damage plant tissue at relatively low concentrations. In March 2008, the U.S. Environmental Protection Agency (EPA) tightened existing National Ambient Air Quality Standards (NAAQS) for O_3 to 75 parts per billion (ppb; assessed as the fourth highest monitored O_3 concentration value over a running average 8-hr period, averaged over 3 continuous years) from the previous 80 ppb, effectively reducing the compliance level of the O_3 NAAQS by 9 ppb. In April 2008, the EPA Clean Air Science Advisory Committee clarified earlier recommendations to the EPA administrator that a primary O_3 standard between 60 and 70 ppb is necessary to protect human health.[5]

O_3 is formed through a complex series of chemical reactions involving nitrogen oxides (NO_x) and volatile organic compounds (VOCs) in the presence of sunlight. To combat rising O_3 levels, these precursors must be reduced. However, as oil and gas development in the western United States continues to accelerate, there is significant potential that emissions from these sources will exacerbate the existing O_3 problem. Although emissions from oil and gas development may appear small as compared with other emission categories such as coal-fired power plants and automobiles, they typically occur in remote regions of the country, far removed from urban areas, and can have a disproportionate effect on the air quality of Class I areas. For example, NO_x emissions from an internal combustion engine at a gas well may react with terpenes (a reactive VOC) emitted from pine forests and form O_3 in an area where the right mix of precursors was previously not available for this reaction to take place. This is especially worrisome because recent observations indicate that many remote wilderness areas and national parks, such as Mesa Verde National Park in southwestern Colorado, are confronted with O_3 concentrations that are trending toward the EPA's acceptable limits. Very near Mesa Verde National Park are rapidly growing oil and gas extraction operations in northwestern New Mexico. As this type of development continues throughout the west, it is essential to understand its potential negative impact on air quality in some of our nation's most cherished protected areas. It is important to notice that wintertime O_3 concentrations exceeding 140 ppb were recently observed near the Jonah-Pinedale Anticline natural gas field in Wyoming's Upper Green River Basin.[6]

This study uses sophisticated meteorological and air pollution models to simulate air quality in the western United States, with a particular focus on O_3 concentrations in our national parks and wilderness areas. The Western Regional Air Partnership (WRAP) provided the necessary inputs to the model for meteorology, emissions, and boundary concentrations, originally developed for regional haze analysis and planning. The modeling system used in this work is similar to other systems used in demonstrating compliance with current NAAQS.[7,8]

Understanding the impacts of emissions from particular source categories such as oil and gas development is crucial to develop effective strategies that help reduce regional air pollution. Although this article focuses on the impact of O_3 pollution, the concept of "one-atmosphere" computer modeling is identified in the WRAP 2008-12 Strategic Plan for future regional air quality analyses.[9] This approach is used to investigate several issues related to regional formation and transport of air pollutants such as the primary and secondary NAAQS for O_3 and particulate matter, visibility protection, and mitigating health and ecosystem effects due to excessive nitrogen deposition and toxic air pollutants such as mercury.

APPROACH

The modeling system comprises three major components: the Penn State University/National Center for Atmospheric Research Mesoscale Model (known as MM5[10]), a regional weather model; CAMx (Comprehensive Air Quality Model with Extensions[11]), a chemistry transport model; and SMOKE (Sparse Matrix Operator Kernel Emissions[12]), an emissions processing system that chemically, spatially, and temporally allocates the raw emissions data. CAMx simulates the emissions, dispersion, chemical reactions, and removal of pollutants in the troposphere by solving the pollutant continuity equation for each chemical species on a three-dimensional grid. Although computationally expensive, this type of simulation accounts for the complex physical and chemical processes that govern the fate of pollutants. The 36-km coarse-grid horizontal domain used for the air quality modeling consists of the contiguous 48 U.S. states, contiguous lands and waters of southern Canada and northern Mexico, portions of the Pacific and Atlantic oceans, most of the Gulf of Mexico, all of the Gulf of California, and the southern Hudson Bay region. The CAMx 36-km grid includes 148 cells in the east-west dimension and 112 cells in the north-south dimension. The vertical grid used in the MM5 modeling defines the CAMx vertical structure. The MM5 simulations used a terrain-following coordinate system defined by pressure using 34 layers that extend from the surface to the model top at 100 mbar. To reduce computational costs, a layer-averaging scheme was adopted, reducing the original 34 layers to 19 vertical layers. Figure 1 presents a map of the computational modeling domain; it also shows the states that form the western region of the United States, the area of interest for this analysis. MM5 provides the wind fields that CAMx needs to determine the transport of chemical species, as well as other meteorological variables such as temperature and pressure. A detailed emission inventory specifies the hourly flux of emissions from numerous area and point pollutant sources. The emission inventory focuses on pollutants that are important for regional haze and visibility in the selected model domain, which includes the contiguous United States, southern Canada, and northern Mexico. The inventory consists of 22 emission categories (e.g., automobiles, power plants, forest fires, and oil and gas development) and was originally developed in support of WRAP's regional haze simulations.[13] Figure 2 shows the annual NO_x emissions associated with oil and gas development in the western United States. Note that significant emissions occur throughout the Intermountain West, particularly in the Four Corners region of northwestern New Mexico.

The oil and gas emission inventory used here was initially compiled for WRAP's regional modeling, with a focus on NO_x and oxidized sulfur (SO_x) emissions, which are precursors to fine particulate nitrate and sulfate, respectively. However, subsequent versions of this inventory have been developed and improved, and emissions of some species, such as VOCs, have been substantially revised. Although this study uses an earlier version of the WRAP oil and gas emission inventory, it is anticipated that the general trends presented provide a gross indication of the impact of this source category on regional O_3 formation.

In this study, a simulation for the year 2002 is performed with CAMx and corresponds to the "base modeling year" being investigated by WRAP and the latest year in which detailed emissions were readily available. The first step in this analysis is the comparison between predicted O_3 concentrations with available observations. Once the model performance of this base-case simulation is deemed adequate, a second CAMx simulation that includes all of the base-case emissions except those from oil

Figure 1. Map of the 36-km computational domain used in this study. The shaded area shows the analysis domain and corresponds to those states that are part of the contiguous WRAP region (Alaska and Hawaii are WRAP members, but are not in the modeling domain). The circles in the figure indicate the location of CASTNET sites used in this study for the model performance evaluation of O_3.

and gas is used to evaluate their air quality impacts in the western United States. The impacts are determined by looking at the difference between the base case and the "absent oil and gas emissions" simulations.

ANALYSIS

Model Performance Evaluation

O_3 concentrations predicted by the model are evaluated by comparing the surface layer values with available

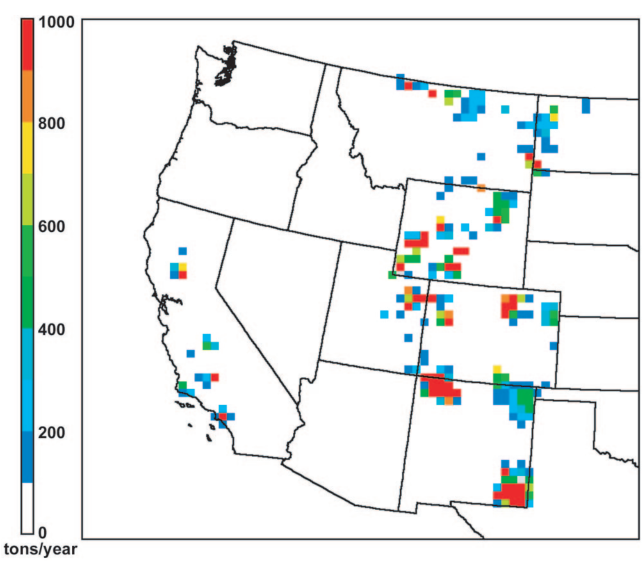

Figure 2. Annual 2002 WRAP NO_x emissions (t/yr) from oil and gas exploration and production activities in the western United States.

hourly measurements of ground-level O_3 at 22 sites from the Clean Air Status and Trends Network (CASTNET)[14] monitoring network. These sites fall within the western region of the United States and are indicated by circles in Figure 1. An evaluation of CAMx's skill in predicting O_3 is done in accordance with the EPA's suggested performance guidelines for O_3 modeling.[15,16] Observation/prediction pairs are excluded from the analysis when the observed concentration is below a certain cutoff level. The EPA has suggested a cutoff value of 60 ppb; however, most of the sites considered here are located in remote, pristine areas, and thus the cutoff value is set at 20 ppb because natural O_3 levels range typically between 10 and 25 ppb.[17] Table 1 shows the annual model performance statistics for 1-hr O_3 in the western region of the United States during 2002. In general, CAMx is able to consistently predict the general annual trends for O_3 concentrations, with a mean normalized bias of −1.6% and a mean absolute normalized error of 22.7%, falling well within the EPA's guidelines for acceptable model performance. Figure 3 shows estimated monthly normalized error and bias bar plots. Throughout the year, the model also performs within EPA goals; for instance, the largest errors are less than 25% during the summer (August). The model seems to show some seasonality in the errors and biases; its performance is better for the winter and fall and slightly worse for the spring and summer. The model has a tendency to underpredict O_3 concentrations during the summer and fall, with the largest biases in August (−15%), whereas it overpredicts O_3 during the winter and spring. Table 1 also shows the

Table 1. Annual model performance statistics for 1-hr O_3 calculated with 22 CASTNET sites in the contiguous WRAP region of the western United States.

Statistic	EPA Goal	Mesa Verde National Park	Gunnison National Park	Canyonlands National Park	Fitzpatrick	CASTNET Sites (Western United States)
Mean observation		46	50	48	48	47
Mean estimation		46	52	43	46	44
Standard deviation observations		10	9	10	8	13
Standard deviation estimates		13	10	11	9	12
Mean bias error		−0.02	2.6	−5	−1.5	−3
Mean normalized bias error (%)	$< \pm 15\%$	0.9	7.3	−8.4	−1.7	−1.6
Mean absolute gross error		8	7	9.6	7.2	10
Mean absolute normalized gross error (%)	$<35\%$	16.9	15.7	19.8	14.9	22.7
Mean fractional error (%)		16.9	14.6	22	15.2	23
Mean fractional bias (%)		−1.4	5.3	−11.9	−3.5	−5.8

Notes: All values in ppb except where indicated.

annual performance statistics for sites located near places for which the impacts from oil and gas emissions will be discussed in the following sections. It is important to notice that for these specific sites the predicted hourly O_3 concentrations also fall within EPA guidelines for acceptable model performance. In general, the performance in most of these sites is better than in the western United States as a whole, with normalized errors ranging from 14.9% (Fitzgerald) to 19.8% (Canyonlands National Park). Many of these sites are located in very complex terrain, so given the coarse resolution of the model, its performance is reasonable and even comparable to that of other studies.[18–20] Figure 4 shows 8-hr moving averages of predictions and observations for the CASTNET sites presented in Table 1. The figure illustrates that the model does not seem to accurately capture the complex diurnal variations in the observations. However, it shows that throughout the year the model follows the general trends revealed by the observations, particularly on a monthly average basis. In the case of Canyonlands, the model variation is larger than the other sites and the model has a pronounced tendency to underpredict observations during the summer and fall.

Oil and Gas Impacts

As indicated above, this study relies on two separate CAMx simulations to estimate the potential impacts of oil and gas emissions in the western United States. A more regional perspective of O_3 formation is illustrated in Figure 5. Figure 5a shows the highest 8-hr O_3 concentration at each model grid cell that occurred during the 2002 base-case simulation. As expected, there are high concentrations (exceeding 110 ppb) downwind of major urban areas such as Los Angeles, San Francisco, Salt Lake City, and Denver. The figure also demonstrates that for a large region of the southwestern United States that includes remote regions of Nevada, Wyoming, Utah, Arizona, New Mexico, and Colorado, the new 8-hr primary NAAQS-related threshold for ground-level O_3 (75 ppb) is exceeded at least once during 2002 for many Class I areas. Generally, these maxima occur during hot, sunny days with light winds, when the meteorology is most favorable for O_3 production. These periods also typically correspond to peak VOC emissions from biogenic and anthropogenic sources. The impact of NO_x and VOC emissions from oil and gas development on O_3 in the western United States is shown in Figure 5b. Note that the values for each grid cell in Figure 5b correspond to the dates for which O_3

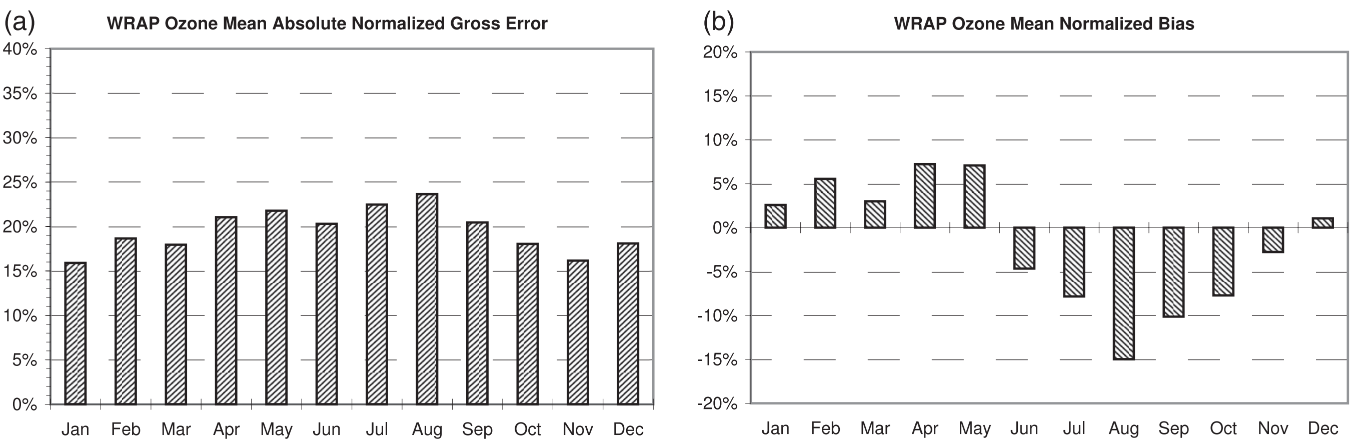

Figure 3. Monthly model performance (a) mean absolute normalized gross error and (b) mean normalized bias bar plots for 1-hr O_3 calculated with 22 CASTNET sites in the WRAP region.

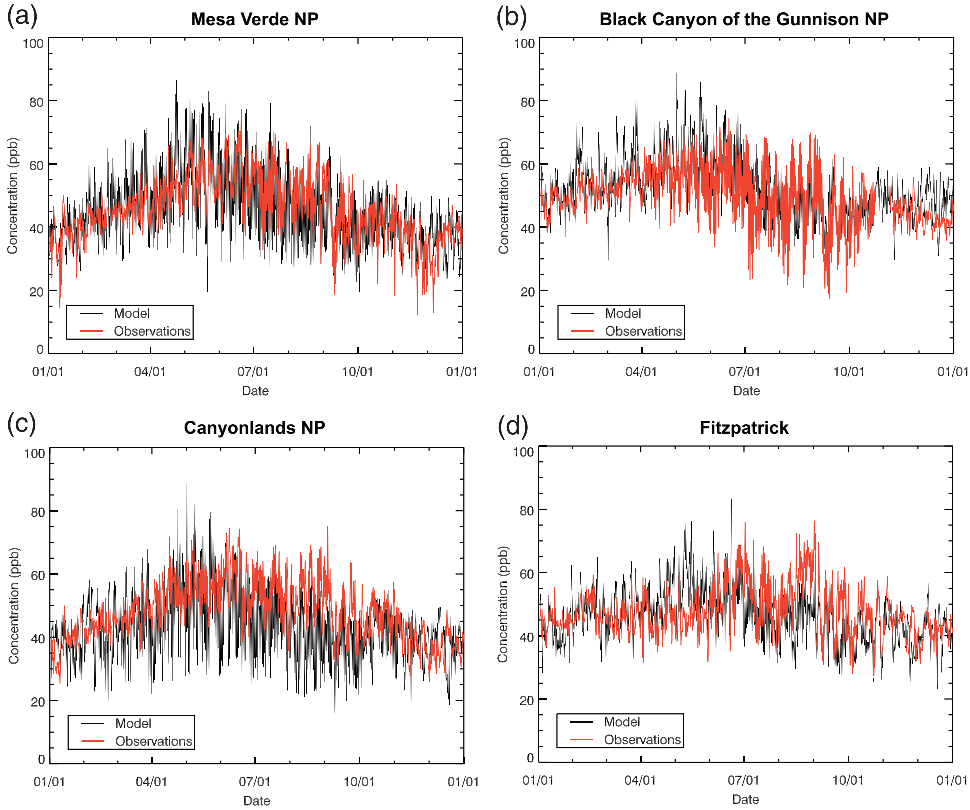

Figure 4. Time series comparison between model (black line) and observed (red line) 8-hr average O_3 (base case) for the CASTNET sites included in Table 1: (a) Mesa Verde National Park, (b) Black Canyon of the Gunnison National Park, (c) Canyonlands National Park, and (d) the Fitzpatrick Class I area included in Table 1.

maxima occur (Figure 5a), but in this case, the O_3 concentration is solely due to emissions from oil and gas development. Although the peak O_3 maxima throughout the west are typically quite small, there is a strong signature of 1–2 ppb of O_3 throughout New Mexico, Colorado, and Wyoming, with a pattern that approximates the

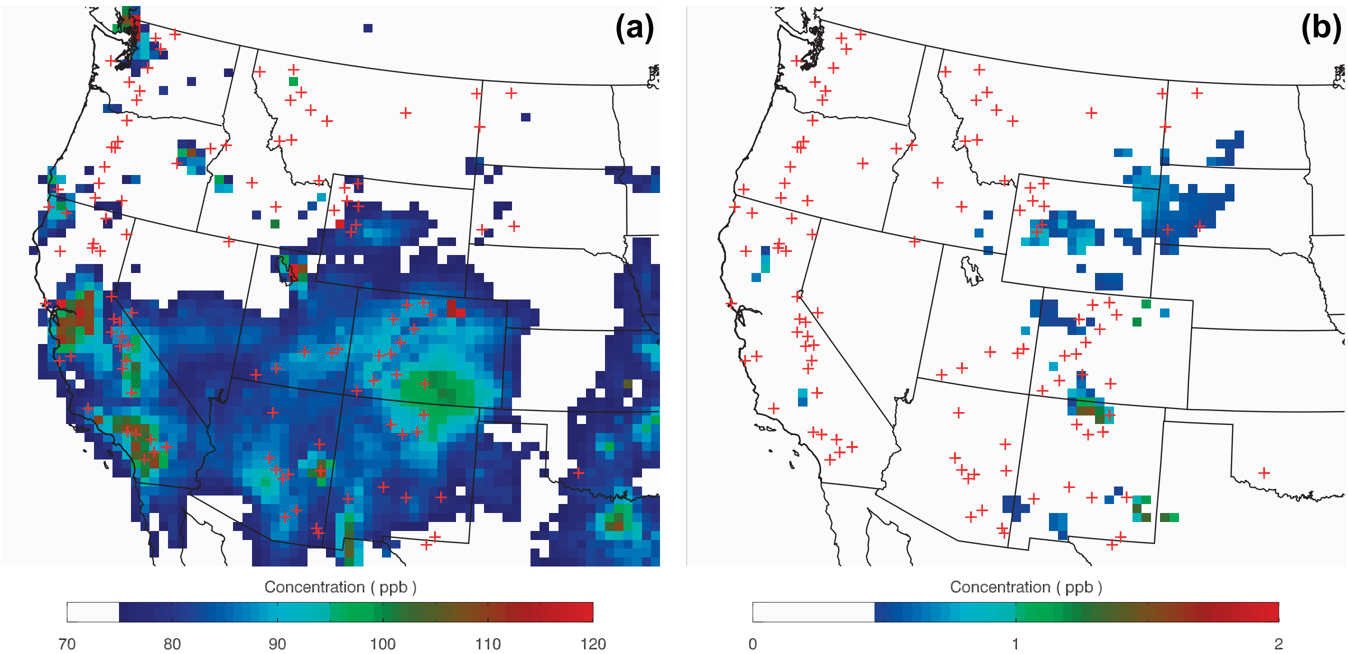

Figure 5. Peak predicted annual O_3 maxima (ppb, 8-hr average) in the western United States from (a) the 2002 base-case simulation and (b) the enhancement from VOC and NO_x emissions from oil and gas development that correspond to the dates and times of O_3 maxima. The locations of all Class I areas in the region are indicated with red crosses.

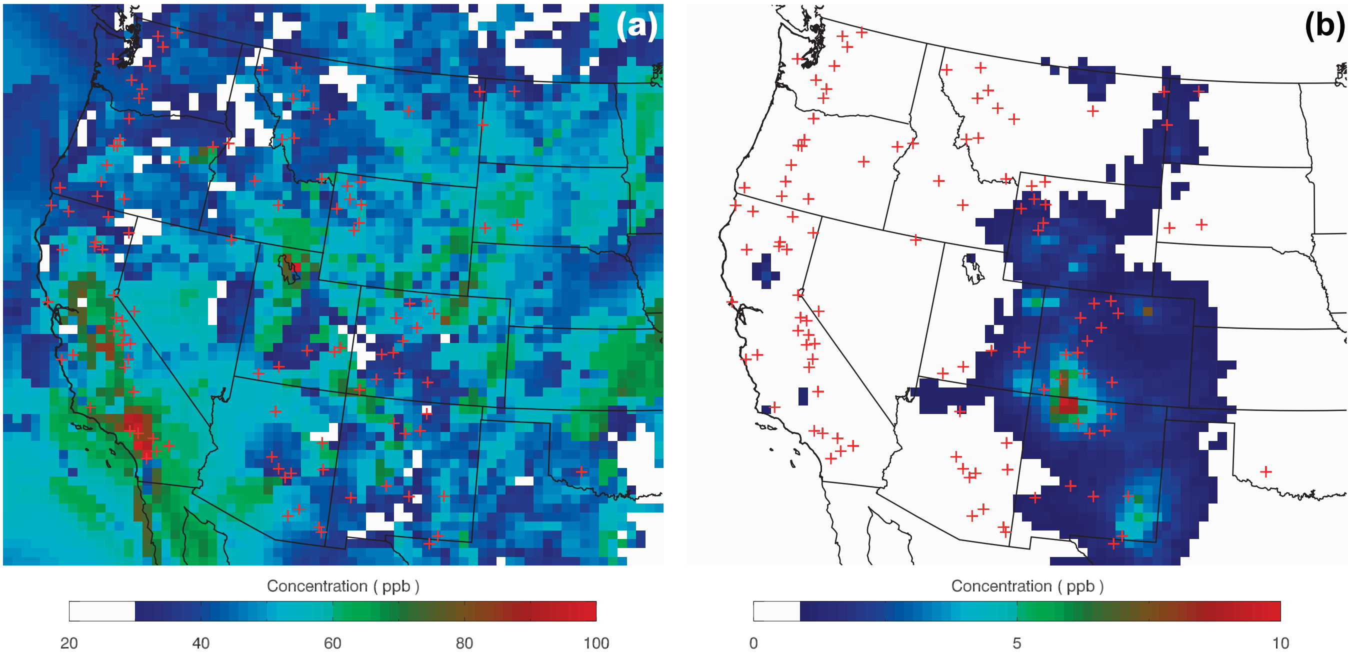

Figure 6. Peak predicted annual O_3 (ppb, 8-hr average) enhancement from VOC and NO_x emissions from (b) oil and gas development in the western United States and (a) corresponding O_3 concentrations from the 2002 base-case simulation. The locations of all Class I areas in the region are indicated with red crosses.

emissions shown in Figure 2. However, the maximum possible impacts of oil and gas emissions do not necessarily coincide in time with the maximum possible O_3 concentrations, as illustrated in Figure 6. The maxima 8-hr O_3 enhancement from oil and gas alone shown in Figure 6b demonstrates that significant O_3 concentrations (maximum of 9.6 ppb) could affect southwestern Colorado and northwestern New Mexico. Class I areas in this region that are likely to be impacted by increased O_3 include Mesa Verde National Park and Weminuche Wilderness Area in Colorado and San Pedro Parks Wilderness Area, Bandelier Wilderness Area, Pecos Wilderness Area, and Wheeler Peak Wilderness Area in New Mexico. O_3 concentrations for the base-case simulation during this period (Figure 6a) range from 40 to 70 ppb; thus in some places (e.g., Mesa Verde National Park and Weminuche) oil and gas have the potential to put these places out of compliance with the new EPA O_3 standard. Figure 6b shows that there are three regions where oil and gas have the potential for maximum impacts on Class I areas: southwestern Colorado and northern New Mexico, the southeast corner of New Mexico, and western Wyoming. Table 2 shows the date when the maximum impacts due to oil and gas emissions are achieved and their corresponding base-case concentrations for some of the Class I area sites. In general, these results show that most of the impacts occur during the summer and early fall. However, from this table alone it is not possible to know, for each site, the percentage of time when high impacts are observed in spring and early summer compared with summer and

Table 2. Maximum O_3 impacts due to oil and gas, date the maxima occur, and base-case concentration in some Class I area sites located in the western United States.

Class I Area	Latitude (°)	Longitude (°)	Base-Case Concentration (ppb)	Maximum Impact Oil and Gas (ppb)	Date Maximum Impact Occurs
Weminuche	37.65	−107.80	40	7	August 5
San Pedro Parks	36.11	−106.81	35	5	September 8
Carlsbad Caverns	32.14	−104.48	49	4	August 27
Wheeler Peak	36.57	−105.42	37	3	August 24
Pecos	35.93	−105.64	40	3	September 13
Bandelier	35.78	−106.26	61	3	June 30
Mesa Verde	37.20	−108.48	64	3	July 13
Saltcreek	33.61	−104.37	49	3	July 29
Great Sand Dunes	37.72	−105.51	33	2	September 8
La Garita	37.96	−106.81	38	2	August 6
Bridger	42.97	−109.75	52	2	April 4
Fitzpatrick	43.27	−109.57	52	2	April 4
Grand Teton	43.68	−110.73	50	1	April 24
Washakie	43.95	−109.59	44	1	September 10

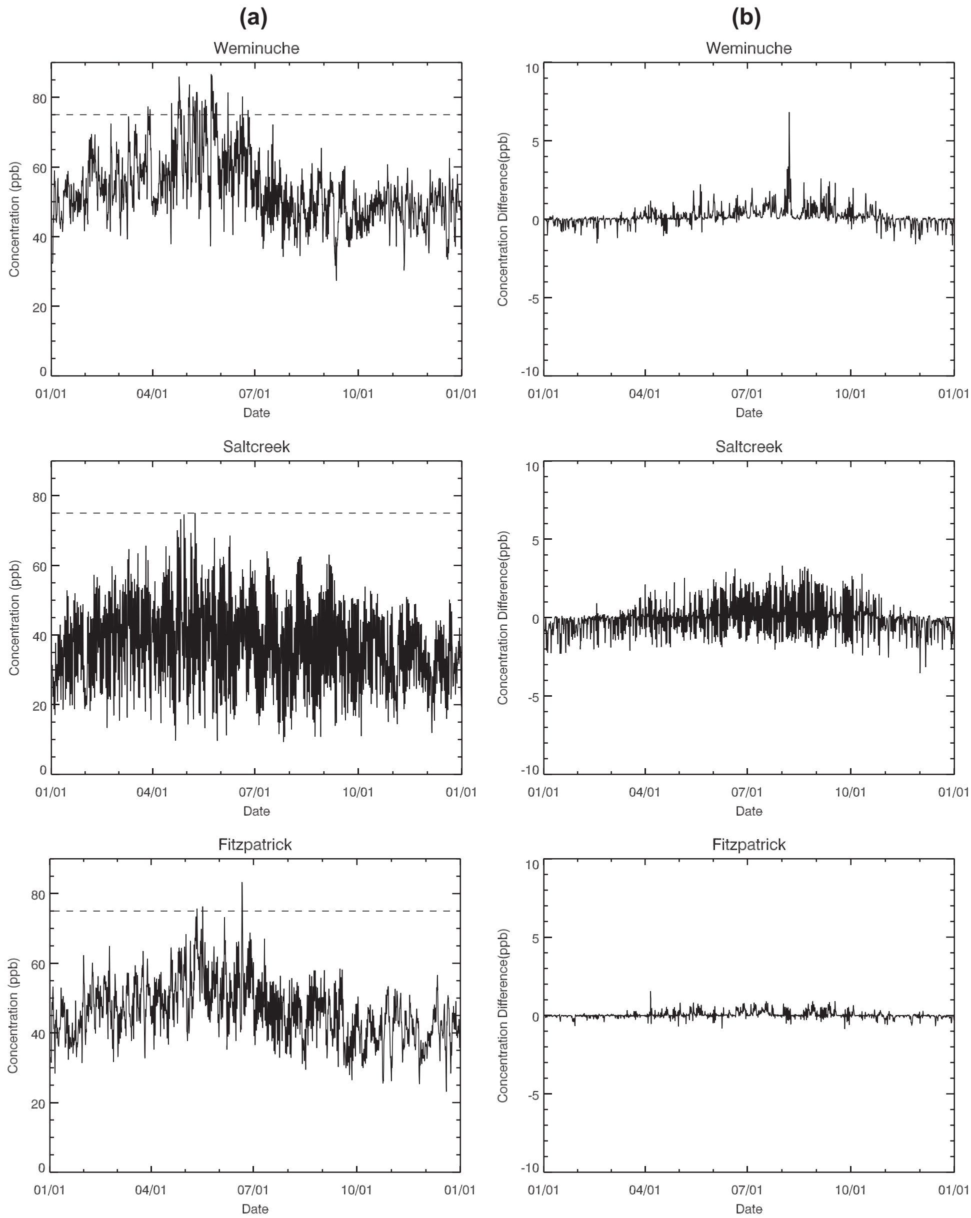

Figure 7. Time series of (a) simulated base-case O_3 (ppb, 8-hr average) for sites representative of one of the three main regions identified as having larger impacts from oil and gas emissions (Weminuche, Saltcreek, and Fitzpatrick Class I areas). (b) The change in O_3 concentration (ppb, 8-hr average) at each site solely due to VOC and NO_x emissions from oil and gas development.

early fall. Figure 7 is a much better indicator of this tendency. Figure 7 shows 8-hr moving average time series for the base case and the oil and gas impacts for a few selected sites from Table 2, including Weminuche, where the largest impacts are observed. The other sites represent one of the other two main regions identified as having larger impacts from oil and gas emissions. The general trend of modeled O_3 (Figure 7a) is low concentrations during the colder winter months, when limited photochemistry will occur, and higher concentrations during the warmer late spring and summer months, when meteorological conditions are more favorable to O_3 production. Additionally, enhanced biogenic VOC emissions that occur during the spring and summer will further influence O_3 formation in the region. The dashed lines in Figure 7a show the new EPA standards for O_3. It is evident from the figure that there are various instances in which O_3 concentrations are higher than the new NAAQS in many of these Class I areas, particularly during the late spring and early summer. Figure 7b shows the resulting changes in predicted O_3 concentrations that are attributed solely to emissions from oil and gas development. This estimate was calculated by evaluating two CAMx simulations: the base-case simulation, in which all emission categories are accounted, and a "no oil and gas" simulation, which is similar to the base case except that oil and gas emissions are removed. The difference between these two simulations represents the contribution of oil and gas emissions on regional O_3. Notable in Figure 7b is the fact that oil and gas emissions can actually decrease O_3 concentrations at various sites through the process of "NO_x scavenging," in which available O_3 is consumed by reacting with nitric oxide (NO). This effect is most prevalent in the winter, when O_3 concentrations are lower. However, in the summer, the situation is reversed, and warm, stagnant conditions yield an increase in O_3 from oil and gas emissions. Although these impacts appear relatively small (e.g., an increase of a few ppb in the summer), it should be remembered that this period corresponds with seasonally high O_3 concentrations.

CONCLUSIONS

A regional air quality model has been applied to the western United States to investigate the impacts of emissions from oil and gas development on O_3 concentrations. Incremental O_3 increases (8-hr average) ranging from less than 1 to 7 ppb were predicted at several western Class I areas, and a peak incremental O_3 concentration of 10 ppb was simulated in the Four Corners region. This study, although not exhaustive, does indicate a clear potential for oil and gas development to negatively affect regional O_3 concentrations in the western United States, including several treasured national parks and wilderness areas in the Four Corners region. It is likely that accelerated energy development in this part of the country will worsen the existing problem. The formation of O_3 pollution examined here represents a complex phenomenon involving nonlinear physical and chemical processes, uncertain emission inventories, and fine-scale transport in mountainous terrain. These simulations will be refined when updated emission inventories are available from WRAP. Regional air quality modeling requires significant resources but remains the only feasible option for developing emission control strategies that have the potential to reduce O_3 concentrations and protect air quality.

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